Community Choice Aggregation
Technical Feasibility Study

Prepared for:
The Cities of Chula Vista, La Mesa, and Santee

FINAL DRAFT

July 16, 2019

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DRAFT

EES Consulting, Inc.

July 16, 2019

Mr. Gary Halbert
City of Chula Vista
276 Fourth Avenue
Chula Vista, CA 91910

SUBJECT: Draft CCA Technical Feasibility Study

Dear Mr. Halbert:

Please find attached the Final Draft Community Choice Aggregation Technical Feasibility Study (Study) for the cities of Chula Vista, La Mesa, and Santee (Partners).

It has been a pleasure working for these Partners and we very much appreciate all the effort this working team has spent on the Study.

Very truly yours,

Gary Saleba
President/CEO

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Glossary

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).

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).

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

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

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 (DA) and CCA entities.

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

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

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

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

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

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

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

Congestion 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.

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

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

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

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

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

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

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

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

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

Firming: Firm capacity is the amount of energy available for production or transmission which 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 (South Path 15) which corresponds closely to the price location which the Partners will pay to supply its load.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Non-Renewable Power: Electricity generated from non-renewable sources or 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.

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

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

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, commonly referred to as "buckets."

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

Resource Adequacy (RA): The requirement that a Load-Serving Entity own or procure sufficient generating capacity to meet its peak load plus a contingency amount (15% 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 resource to meet that demand.

Shaping: Function that facilitate and support 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. As of the date of completion of this Study, SVCE had not yet launched service.

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

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

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

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

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).

WREGIS: The Western Renewable Energy Generation Information System (WREGIS) is an independent, renewable energy tracking system for the region covered by WECC. WREGIS tracks renewable energy generation from units that register in the system by using verifiable data and creating renewable energy certificates (REC) for this generation.

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

Executive Summary

Introduction

To meet clean energy and sustainability objectives, the cities of Chula Vista, La Mesa, and Santee approved funding for a technical feasibility study (Study) evaluating Community Choice Aggregation (CCA). Under the CCA 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) continues to provide distribution and billing service.

California Assembly Bill 117 allows local governments to form CCAs that offer an alternative electric power option to constituents currently served by IOUs. CCAs face the same requirements for renewable energy purchases as the incumbent IOUs and 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.

There are currently 19 operational CCAs in the State, representing 109 different cities and counties and nearly 20% of the state's energy load. Cities with CCA programs cite benefits of local control, customized energy programs, customer choice, higher renewable energy to support climate action plan goals, and competitive rates.

Study Goals

The goal of the Study is to determine whether a CCA program(s) could be established to meet the greenhouse gas (GHG) emissions reduction goals of the Partner cities while keeping electricity rates comparable to or lower than those of the incumbent utility. To do this, the Study will:

- Evaluate the financial feasibility of a potential CCA for the cities of Chula Vista, La Mesa, and Santee (Partners). Financial feasibility for both a larger Partner CCA and individual CCAs for each city were also evaluated.
- Assess whether a CCA program can help the cities achieve climate action plan goals, including 100% renewable electricity by 2035.
- Evaluate governance options for CCA, including:
  - <u>Enterprise</u> – Each city operates its own CCA
  - <u>Partner CCA</u> – A 3-city CCA program with Chula Vista, La Mesa, and Santee
  - <u>Enterprise JPA</u> – Cities each have their own CCA but join with other jurisdictions to form a JPA of CCAs. Administration costs are shared but power supply procurement is unique to each CCA member.

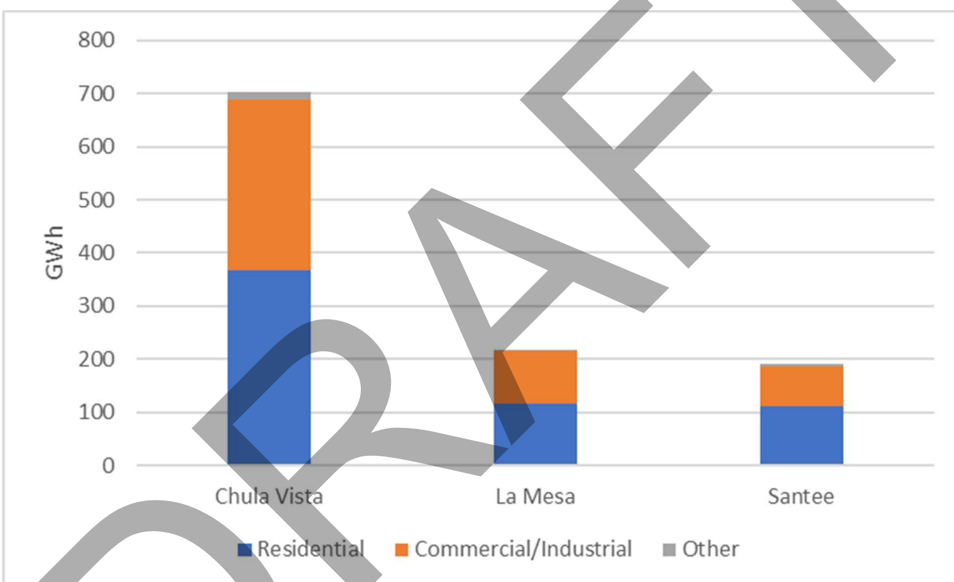
- Regional CCA – Join the City of San Diego-led efforts to form a SDG&E regional CCA through JPA agreements between each jurisdiction
- Other JPA Option – Partner with operational CCA, Solana Energy Alliance

- Evaluate risks and benefits of a CCA

Study Assumptions and Scenarios

Load data from the Partners was provided by SDG&E. Exhibit ES-1 shows the amount of energy consumed in each of the Partner cities in 2018. Residential and commercial customers make up the majority of energy use across all cities. The Other category includes street lighting and agriculture.[1]

Exhibit ES-1
2018 Load by City



At this time, SDG&E's resource mix is 44%[2] GHG-free due to power supply from renewable resources. SB100, adopted in 2018, accelerates the state-mandated Renewable Portfolio Standard (RPS) obligations as follows:

- 44% renewable by 2024;
- 52% renewable by 2027;
- 60% renewable by 2030; and
- 100% GHG free by 2045

[1] The Commercial category includes all commercial customers plus industrial customers. Agriculture is primarily irrigation pumping.

[2] https://ww2.energy.ca.gov/pcl/labels/2017_labels/SDG_and_E_2017_PCL.pdf

While a high-level analysis of other governance options is evaluated in the Study, the Study calculations assume the Partners will proceed with the Partner CCA operating model as this approach will offer greater economies of scale and financial efficiencies when compared to individual CCAs. The Study also assumes that the Partner CCA would purchase power supply that meets SB100 and SB350 requirements for renewable energy, long-term contracts, and complies with all other related CPUC regulations. The Study evaluated power supply for a potential Partner CCA program, operating costs, and compared those expenses to forecasted SDG&E rates. All rate discounts or bill savings referenced throughout the Study are the savings off the bundled SDG&E rates which includes energy supply, transmission, distribution, and other charges.

To provide information about the cost difference between renewable resource portfolios, this Study analyzes the 4 scenarios detailed in Exhibit ES-2.

Exhibit ES-2
Partner CCA Resource Portfolios Evaluated

	% Renewable[1] at Launch (2021)	% Renewable in 2030	Meets 100% Renewable by 2035
Scenario 1: SDG&E Equivalent Renewable Portfolio	46%	60%	No
Scenario 2: 50% Renewable at Launch, with 100% by 2035 Portfolio	50%	86%	Yes
Scenario 3: 75% Renewable at Launch, with 100% by 2030 Portfolio	75%	100%	Yes
Scenario 4: 100% Renewables Portfolio at Launch	100%	100%	Yes

[1]Renewable includes only RPS eligible resources. All eligible renewable resources are greenhouse gas free in this study.

Key Findings

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

- CCA customer bills are predicted to be at least 2% lower than forecast SDG&E total bills. Put another way, a hypothetical customer with a $100 SDG&E electric bill could expect a $98 bill under the CCA. These calculations include conservative modeling parameters and assume participation rates for residential customers of 95% and non-residential customers participation rates of 85%. Recently-launched CCAs throughout the state have experienced participation rates near 98%.

- Electricity cost savings are estimated to average about $7.1 million per year for residents and businesses located within the three cities.

- CCA start-up and working capital costs (estimated at $12 million, and assumed to be financed) could be fully recovered within the first five years of CCA operations while still achieving a 2% rate discount compared to SDG&E's forecast rates.

- The Study analyzed CCA rate results under scenarios with high and low participation rates, high and low market power costs, and high and low stranded costs. The findings identify key risks with regard to stranded cost recovery (via SDG&E) and power supply. The Study's section on Risks and Sensitivity Analysis describes the magnitude of those risks and measures for mitigating risks.

- The CCA will have an average, annual $8.5 million surplus revenue stream that can be used for customer-related programs such as:
  - Funding for customer energy efficiency programs.
  - Local renewable energy resource programs, such as renewable energy net-metering.
  - Customer rate savings beyond the 2% target.

- The rate savings to customers under the Partner's CCA would drive additional local economic development benefits, such as 86 new jobs and a total of $10.3 million in annual economic output.

- If the CCA program purchased power supply that required 100% renewable energy use by 2035, the CCA program would help the Partners meet renewable energy Climate Action Plan goals. Under this scenario, the CCA could still offer a 2% bill discount off forecast SDG&E bills in 2035.

- While all governance models are viable and offer some savings, a high-level analysis for joining the San Diego CCA illustrate the economies of scale, ease of implementation, and other considerations for partnering with the City of San Diego's CCA efforts.

Key Operating Figures for a Partner CCA as modeled against SDG&E's projected power portfolio are shown in Exhibit ES-3 below. The analysis assumes SDG&E will meet future RPS requirements; however, SDG&E might choose a more renewable power content. Without additional information on SDG&E's plans, the RPS power content assumption is the next best estimate.

Exhibit ES-3 Partner CCA Key Operating Figures				
Power Supply Portfolio Scenario:	**Scenario 1: SDG&E Equivalent Renewable**	**Scenario 2: 50% Renewable at Launch 100% Renewable by 2035**	**Scenario 3: 75% Renewable at Launch 100% Renewable by 2030**	**Scenario 4: 100% Renewable**
2022 Operating Budget, $ million	$74.3	$75.9	$80.4	$86.9
2022 Revenues, $ million	$79.5	$79.5	$79.5	$82.7
2022 Load Served, GWh	1,031	1,031	1,031	1,031
Average Operating Budget, $ million	$81.1	$84.8	$89.0	$92.3
Average Revenues, $ million	$91.5	$91.5	$91.5	$95.0
Average Net Revenues, $ million	$10.5	$6.7	$2.5	$2.7
Average Load Served, GWh	1,035	1,035	1,035	1,035
Startup Loan (Including Pre-Startup Costs and Working Capital), $ million	$10	$12	$12	$21
Startup Loan Term, years	5	5	5	5
Average Rate Discount, %	2%	2%	2%	1%
Economic Impacts: San Diego County	86 Jobs/year	86 Jobs/year	86 Jobs/year	44 Jobs/year
	$10.3 million in output/year	$10.3 million in output/year	$10.3 million in output/year	$5.2 million in output/year
Greenhouse Gas Reductions, tons CO2/year	0	55,261	127,832	173,106

Governance

Should the Partners choose to implement a CCA, the cities will need to decide on an appropriate governance structure and fund some of the related upfront costs of implementing the CCA program. The Study evaluated five governance options, which include:

- Enterprise – Each city operates its own CCA
- Partner CCA – A 3-city CCA program with Chula Vista, La Mesa, and Santee
- Enterprise JPA – Cities each have their own CCA but join with other jurisdictions or form a JPA of CCAs. Administration costs are shared but power supply procurement is unique to each CCA member.
- Regional CCA – Join the City of San Diego-led efforts to form a SDG&E regional CCA through JPA agreements between each jurisdiction
- Other JPA Option – Partner with operational CCA, Solana Energy Alliance (SEA)

A summary of the findings is provided in Exhibit ES-4 and a description of each is outlined below.

Exhibit ES-4
Summary of Estimated Costs to Establish CCA by Governance

	Enterprise	Partner CCA	Regional CCA	JPA with SEA	Enterprise JPA
Pre-Launch Costs	$600,000-800,000 (each)	$600,000-800,000	$0	Not Determined	$600,000-800,000
Start-Up and Working Capital (Financed)	Chula Vista: $5 million La Mesa: $4 million Santee: $3 million	$10-$12 million	$0	Some fee may be required	Chula Vista: $5 million La Mesa: $4 million Santee: $3 million
Estimated Bundled Rate Discount	Chula Vista: 2% La Mesa: 1% Santee: 1%	2%	At least 2%	Undetermined	2%
Probable Launch Date	2022	2022	2021	2022	2022
Power Supply Cost Allocation	Power supply obtained individually	Power supply obtained at the same time	Shared power costs	Power supply obtained incrementally	Power supply obtained individually

Enterprise – As an enterprise, a city-only CCA retains the greatest amount of local control for program organization and power supply. Discretionary revenues above what is needed to run the CCA program stay within each jurisdiction. Power supply choice and rate discounts are unique to each CCA; however, the enterprise fund would not benefit from sharing administration costs. Duplicate efforts would be made to implement each city CCA and the resulting rate discounts offered might be lower compared to a joint powers authority (JPA) option. Also due to the cost duplication in the enterprise option, the city CCAs may not be able to offer power supply with a greater share of RPS-qualifying resources compared with a JPA option. An enterprise option is well suited for jurisdictions who do not have partners with similar goals and culture. The City of Solana Beach set up an enterprise CCA but are now looking for partners to join them (discussed below in Other JPA Options). This willingness to partner suggests value in JPA governance structures.

Partner CCA – A Partner CCA is explored in this Study to demonstrate the financial feasibility of a CCA program. Under this option each city council would pass an ordinance to form a CCA and join a negotiated JPA. The JPA operates as its own entity and typically is governed by a board consisting of one elected official from each partner city. The pre-launch costs (estimated in ES-4) would be shared among the JPA members. Under a Partner JPA, the CCA would have a larger customer base, and could possibly offer higher rate discounts and/or additional flexibility in program choice or power supply portfolio. A high level of local control is maintained; however, the Partners might expect to be more involved in day-to-day operations of the CCA compared with joining a larger, Regional JPA (discussed below).

Enterprise JPA – Partnering with any of the other cities or the county could also take the form of an Enterprise JPA where each member is its own CCA and is responsible for its own power supply. In this model administration costs are shared. This might be a good option for smaller jurisdictions to obtain economies of scale for administration cost sharing, but each member retains flexibility and local control in power supply including rate programs and discounts. The Enterprise JPA model is made up of individual CCAs; therefore, contracts for power supply are entered into by each city and may not afford the same protections of general fund liability as the JPA model. This governance option has not been used in SDG&E service territory yet. An example of an Enterprise JPA is CalChoice operating in Southern California Edison's service area.

Regional CCA – The City of San Diego is requesting interested jurisdictions to join together to operate a regional CCA program under a JPA. The City of San Diego has been conducting work group meetings to discuss JPA governance terms and framework with interested jurisdictions. The City has further stated that it will provide the start-up costs and working capital needed for the program, which could be a significant benefit to the Partners. A Regional CCA is expected to provide economies of scale for administration costs resulting in an additional estimated 0.8% in rate savings. These administration cost savings could provide additional rate savings or programs depending on how the Regional CCA sets its internal goals. These savings could be offset if the Regional CCA introduces a power supply that is greener than what the Partners desire. Overall, a Regional CCA would likely be more cost-effective compared with a Partners Only JPA.

While participation in the Regional CCA would have additional economies of scale benefits, there would be a trade-off in the level of local control. Existing CCA JPA agreements do not generally have language guaranteeing new program funding for each JPA member and there is a possibility that the new program benefits of a Regional CCA would not be equally shared across all members. Finally, a Regional CCA program has the potential to grow to 18 or more members compared with a Partner JPA that could limit the number of partners in its agreement. While 18 members is not as large as some operating CCAs, there is some uncertainty in the amount of local control that would be retained for the Partners. Also, with large JPAs, quorums are more difficult to achieve and the decision-making often shifts to committees.

If the Partners wish to join the Regional CCA, the respective city councils likely need to vote by September 2019 to initiate the first round of JPA negotiations for a launch date as early as 2021. This option is attractive in terms of timing and the benefit of not having to come up with capital for pre-launch activities.

Other JPA Options – Other CCA technical feasibility studies in SDG&E service area include Encinitas, Oceanside, Del Mar, Carlsbad, and San Diego County. The Partners could join with any of these jurisdictions if they do not ultimately join the Regional CCA. This option would be further off in the future and would likely result in the earliest launch date of 2022.

Finally, the City of Solana Beach is currently operating the Solana Energy Alliance (SEA) and has responded to a recent Request for Information (RFI) indicating interest in partnering to form a JPA with other cities. In the case of SEA, a JPA would need to be negotiated including likely changes in the structure and consultant contracts SEA currently maintains. SEA's current contracts may be limiting; however, these limitations might also be offset by the experience SEA brings to the CCA launch process. A final consideration for a possible partnership with SEA is that the Partner's loads are over ten times greater than SEA's load. Due to the size difference, the current SEA contracts and structures may not be a good fit. Specifically, the Partner's load is large enough to support a full CCA staff. SEA loads are relatively small for a CCA, and so staff is limited to a director with all other functions being completed by consultants. A JPA with SEA could take the form of an Enterprise JPA model or a JPA CCA model. Recall that the Enterprise JPA model is a JPA between individual CCAs while a JPA CCA is a CCA formed through JPA. The distinction is important when designing agreements that protect general fund liability.

Risks

While the study shows that forming a CCA is financially feasible under a wide range of scenarios, doing so is not without risk. The feasibility of the CCA; that is maintaining customer rates competitive with SDG&E primarily depends on power supply costs (which make up over 90% of the overall CCA operating budget); and how those costs compare to SDG&E's power supply costs and ultimately their customer rates. Other factors impacting the financial viability of the CCA include: costs that 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 the risks imposed on the CCA by these factors, the Study includes a Sensitivity and Risk Analysis section which established a range of high and low scenarios for: prices for CCA-procured market power, SDG&E's customer rates, CCA financing costs, and the level of SDG&E's PCIA. As a result of the impact on CCA rates of these risk scenarios, the Sensitivity and Risk Analysis section also assumed a worst case CCA customer retention level and its impact on CCA rates.

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 may take to manage those risks. The risk mitigation actions consist of industry standard best operating practices and strategies employed by other operating CCAs including: conservative power procurement strategies employing market risk management policies, developing a cash reserve fund from annual net revenues, and engaging in regulatory and legislative issues through the Statewide CCA group – the California Community Choice Association (CalCCA).

Conclusions

The Study results suggest that CCA implementation is financially feasible for a Partner CCA or other JPA structure. The economies of scale realized within a Partner CCA are sufficient for stable operation under a wide range of financial assumptions and sensitivities. A Partner CCA can be established in 2019 with a launch date of 2021 if a JPA is put into place by October 2019 with an implementation plan filed at the California Public Utilities Commission (CPUC) in December 2019.

This schedule has a short time-frame, and if the decision is delayed by a month, the launch date would be shifted to 2022.

Additionally, the individual city analyses showed that each of the Partners could implement its own CCA program. Based on the study's conservative assumptions, the City of Chula Vista is large enough to offer a 2% bill discount while offering a power supply portfolio consistent with the power supply content in Scenario 2 (50% renewable at launch and 100% by 2035). La Mesa and Santee are smaller cities but could potentially offer bill discounts as well, but with a lower projected discount of 1% as there are fewer customers over which to spread fixed administration costs. Both La Mesa and Santee are larger than the currently operating SEA which has provided a 3% total bill discount compared with SDG&E. The savings SEA has offered are greater than what is estimated in this study which might be attributed to the exit fee vintage as well as the conservative forecasts in this study which estimate higher power supply costs going forward. Savings offered by SEA may also change in the future.

The Partner's CAP goals for renewable energy are well aligned with the City of San Diego goals. If the Partners wish to be part of the Regional CCA, the CCA would launch in 2021 and the Partners would have the benefit of not having to put money in up front for pre-launch activities.

Suggested next steps for the Partners include: complete an internal review of this Study, conduct public outreach activities to share the results of the Study with constituents and other stakeholders and receive their input, adopt the Study results through City Council actions and determine whether to move forward with CCA implementation. Each Partner should continue to evaluate governance options and assess which are best aligned with City goals.

Introduction

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, 19 CCAs comprising multiple counties and cities are operating with more scheduled to commence operations in 2020 and 2021. To better understand the benefits and risks associated with CCA programs, the cities of Chula Vista, La Mesa, and Santee (Partners) selected EES Consulting to prepare a report that assesses the feasibility of CCA operations as a mechanism to offer cost competitive rates to customers and to meet city Climate Action Plan goals for renewable energy utilization and greenhouse gas (GHG) reductions. In this report, EES examines the technical and financial viability of a CCA program to serve Partner city constituents.

Exploring a CCA program is an important part of evaluating the Partner's clean energy future. A CCA program would give the Partners local control over power supply and revenue to fund clean energy-related programs. The Study models power supply and operating expenses against the alternative service from SDG&E and finds that a CCA can provide lower electric rates while meeting or exceeding State mandates for renewable power utilization. The Sensitivity and Risk Analysis confirms these findings under a range of factors impacting financial viability for a Partner-operated CCA.

While the primary analysis provides the feasibility results for the case where the Partners operate their own CCA, other options are available such as joining the Regional CCA effort led by the City of San Diego or teaming with other jurisdictions. These other options could result in additional cost savings but might also impact local decision-making authority. These trade-offs are introduced in the Governance Section of the Study.

The Study assumes that a CCA created among the Partner cities would directly support the cities' Climate Action Plans (CAPs), and would generally aspire to meet the following objectives:

- Decrease GHG emissions from electricity generation
- Increase the renewable energy in the power mix to exceed the baseline power mix offered by SDG&E, including the 100% Clean Energy goals set by the Partner's CAPs
- Provide competitive rates
- Provide local control over rate setting
- Provide customer choice to residents and businesses
- Reinvestment of residual revenue in local renewable power initiatives
- Promote and incentivize community-focused CCA programs which also support the Partners' CAP objectives

While the Partners have not yet officially adopted these CCA goals, they serve as the foundation for this Study. Once the Partners' CCA program goals are refined, adopted, and prioritized, modifications to this Study may be appropriate.

Study Methodology

This Study evaluates the estimated costs and resulting rates of operating a Partner CCA and compares these rates to a SDG&E rate forecast for the years 2021 through 2030. This pro forma financial analysis models the following cost components:

- Power Supply Costs:
  - Wholesale purchases
  - Renewable purchases
  - Procurement of resource adequacy (RA) capacity (System, Local and Flexible capacity products)
  - Other power supply and charges
- Non-Power Supply Costs:
  - Start-up costs
  - CCA staffing and administration costs
  - Consulting support
  - SDG&E and regulatory charges
  - Financing costs
- Pass-Through Charges from SDG&E:
  - Transmission and distribution charges
  - Power Charge Indifference Adjustment (PCIA)
  - Rule 20a - undergrounding

The information above is used to determine the projected retail rates for the CCA. The CCA rates are then compared to the SDG&E projected rates for the Partners' CCA service area. After these rate comparisons are made, the attendant economic development and GHG comparisons are made. Operational and governance options are discussed, as well as a sensitivity analysis of the key variables contained in the Study.

Study Organization

This Study is organized into the following main sections:

- Load Requirements
- Power Supply Strategy and Costs
- Partners' CCA Cost of Service
- Product, Service and Rate Comparisons
- Environmental/Economic Considerations
- Sensitivity Analysis
- CCA Governance
- Conclusions and Recommendations

Load Requirements

One indicator of the viability of a CCA for the Partners 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.

Historical Consumption

SDG&E provided hourly historical data on energy use (kWh) for customers receiving power supply services from SDG&E (bundled customers) in each of the three cities for the 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.[3] 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 ESP.[4] Once operating, the CCA may decide to provide service options to DA customers with expired contracts, but our approach offers the most conservative analysis of feasibility and omits them from the Study.

EES aggregated this data by rate class (residential, commercial, agricultural) in each month for bundled customers (full service SDG&E customers, excluding DA customers). In total, bundled residents and businesses within the three cities purchased 1,108 GWh of electricity in 2018 from SDG&E.

Exhibit 1 summarizes energy consumption and number of accounts for bundled customers in 2018.

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

[4] 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.

Exhibit 1
Load and Accounts in 2018 (Three Cities)

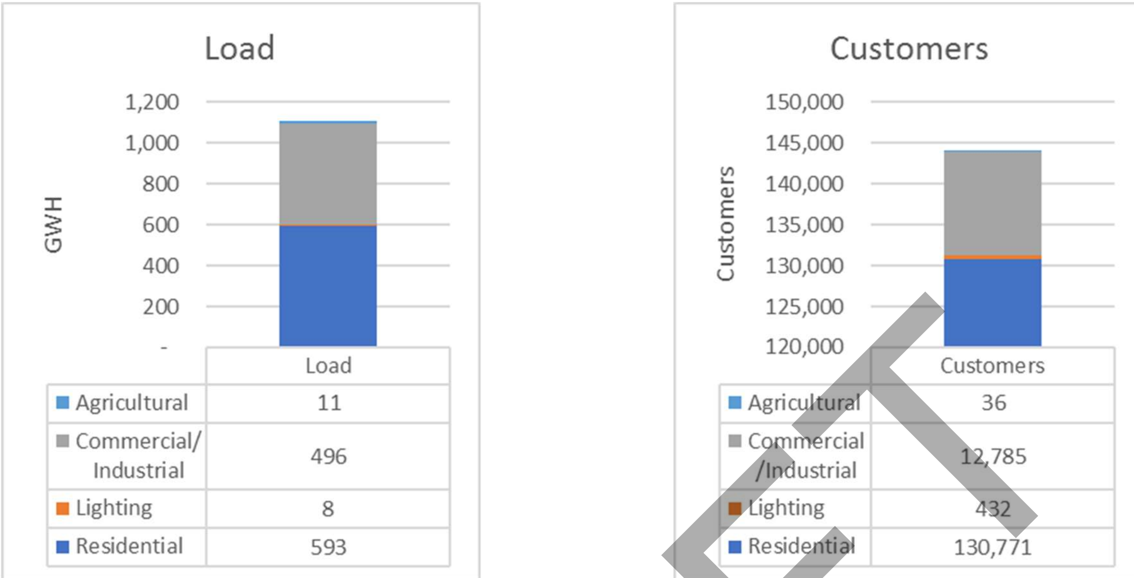
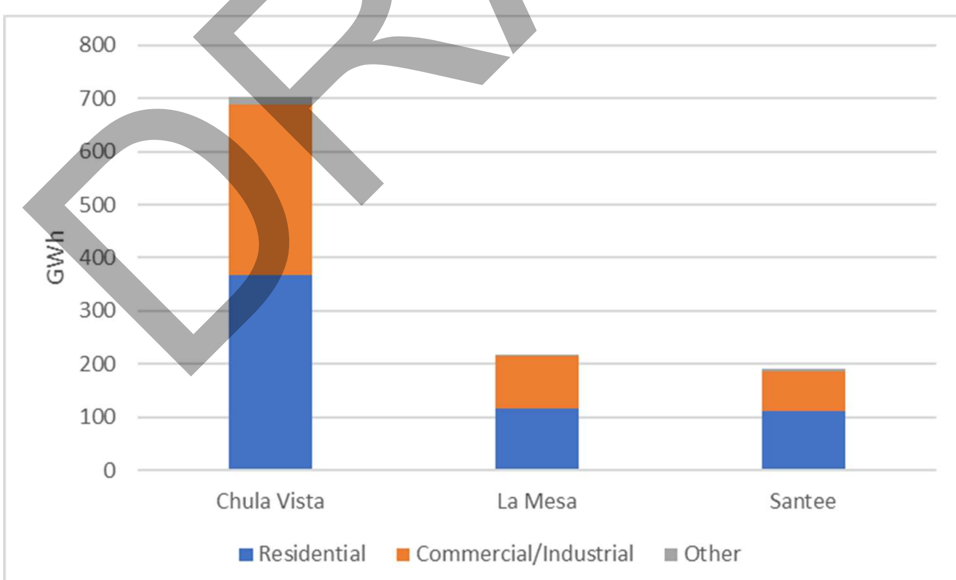


Exhibit 2 shows the aggregate amount of energy consumed in each of the Partner cities in 2018. Chula Vista has the highest consumption while residential and commercial[5] and industrial customers make up the majority of energy use across all cities.

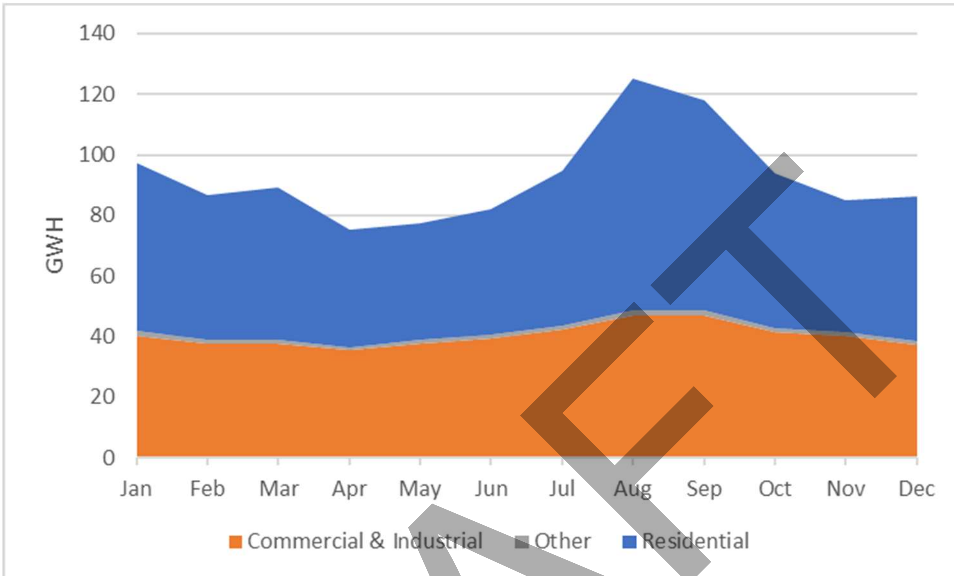
Exhibit 2
2018 Load by City



[5] A small commercial customer would typically be a convenient store or smaller office building, while a medium/large commercial customer might be a grocery store.

Monthly historic load from 2018 is shown in Exhibit 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.

Exhibit 3
2018 Monthly Aggregated Partner Load



CCA Participation and Opt-Out Rates

Before customers are served by a CCA, they receive two notices with their monthly energy bills 60 days and 30 days before the CCA's launch, and another two notices 30 days 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 IOU. All customers that do not follow the opt-out process specified in the customer notices prior to launch would be automatically enrolled into the CCA.[6]

As such, the Partners' 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 Partners' CCA bills processed by SDG&E would show separate charges for power supply procured by the CCA, all other charges related to delivery of the electricity by SDG&E and other utility charges that would continue to be assessed.

[6] 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 assumes an overall customer participation rate of 85% for the Commercial and Industrial accounts. For residential accounts, it is assumed that approximately 95% of customers would remain with the Partners' CCA. For commercial and industrial accounts, the participation rate is 85% which adjusts historic participation rates for the new cap on direct access.[7] 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. Operating CCAs in California have experienced overall participation rates ranging from 83% (Marin Clean Energy) to 98% (Peninsula Clean Energy). On average, 90% of all potential customers have stayed with their CCA.[8]

Conceptual CCA Launch

The California Public Utilities Commission (CPUC) issued Resolution 4723, which requires that new CCAs file their Implementation Plan by January 1, resulting in the earliest possible Partner CCA launch date of January 1 the subsequent year. Under this requirement, the Partners' earliest possible launch date is early 2021 if an Implementation Plan is filed by January 1, 2020. This Study assumes that service would be offered to all customers by April 2021 as outlined in Exhibit 4. A launch date in April is assumed based on analysis of cash flow requirements for start-up CCAs. The timing of revenue and SDG&E seasonal rates as well as power supply purchases and the seasonal nature of energy costs mean that a spring launch is preferred so that working capital requirements can be minimized. Additionally, SDG&E summer rates begin in June; in order to avoid customer confusion, CCA service should begin prior to the rate change which typically increases customer bills. Best practices for CCA launch indicate that the first CCA bill should be based on the lower winter rates.

[7] 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

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

Exhibit 4 CCA Customers, Loads, and Revenues					
Assumed Start	**Eligibility**	**Customer Accounts**	**Total Load (GWh)**	**Peak Demand (MW)**	**CCA Operating Revenues**
21-Apr	All Customers	138,327	768	256	$53 million
First Full Year of Operation: 2022	All Customers	138,958	1,032	257	$79 million

This launch strategy, would enable the Partners' CCA to provide service to all customers as soon as possible. The number of customers and projected total load is similar to the number of customers enrolled by other CCAs launching in a single phase,[9] therefore a phased rollout of the Partner CCA Program is not necessary.

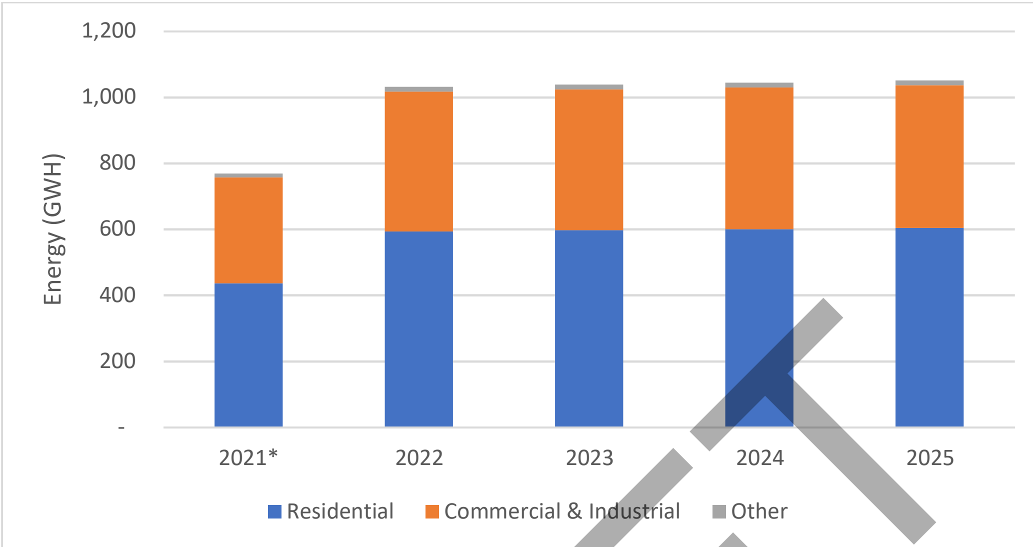
Forecast Consumption and Customers

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 the Partners' CCA over the next five years is shown in Exhibit 5. The CCA forecast of GWh sales in Exhibit 6 reflects the single-phase roll-out and customer enrollment schedule discussed previously. Annual wholesale energy requirements are also shown below in Exhibit 6 ("Total Load" column).

[9] For example, Silicon Valley Clean Energy enrolled 180,000 residential customers and Monterey Bay Clean Energy enrolled 235,000 residential customers at one time.

[10] Growth rate applies to total SDG&E service area. http://www.energy.ca.gov/2017_energypolicy/documents/

Exhibit 5
Projected Load by Sector (Three Cities)[1]



*2021 loads are lower due to partial year beginning in April.

Exhibit 6 CCA Projected Annual Energy Requirements (GWh)			
Year	**Total Retail Sales**	**Losses[11]**	**Total Wholesale Load**
2021	769	35	804
2022	1,032	47	1,079
2023	1,038	48	1,086
2024	1,045	48	1,093
2025	1,051	48	1,100
2026	1,058	49	1,106
2027	1,064	49	1,113
2028	1,071	49	1,120
2029	1,078	50	1,127
2030	1,084	50	1,134

[11]Transmission and Distribution power losses were estimated at 4.6% based on the California Energy Commission's 2019 Integrated Energy Policy Report Docket Number 19-IEPF-03 Form 1.2. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03

Power Supply Strategy and Costs

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

Long-term resource planning involves load forecasting and supply planning on a 10- to 20-year time horizon. Prior to launch, the Partners' CCA planners would develop integrated resource plans that meet the Partners' CCA Program 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 Partners' 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.

Resource Strategy

This Study assumes that the Partner CCA would be interested in minimizing overall community energy bills, achieving GHG emissions reductions, stimulating local economic development to achieve CAP goals, and meeting or exceeding the State's renewable energy requirements. The CCA can likely achieve these goals within 5 years 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 sufficient resources each hour to serve all of the CCA customer loads. The CCA policymakers would guide the power supply acquisition philosophy to achieve the CCA's policy objectives.

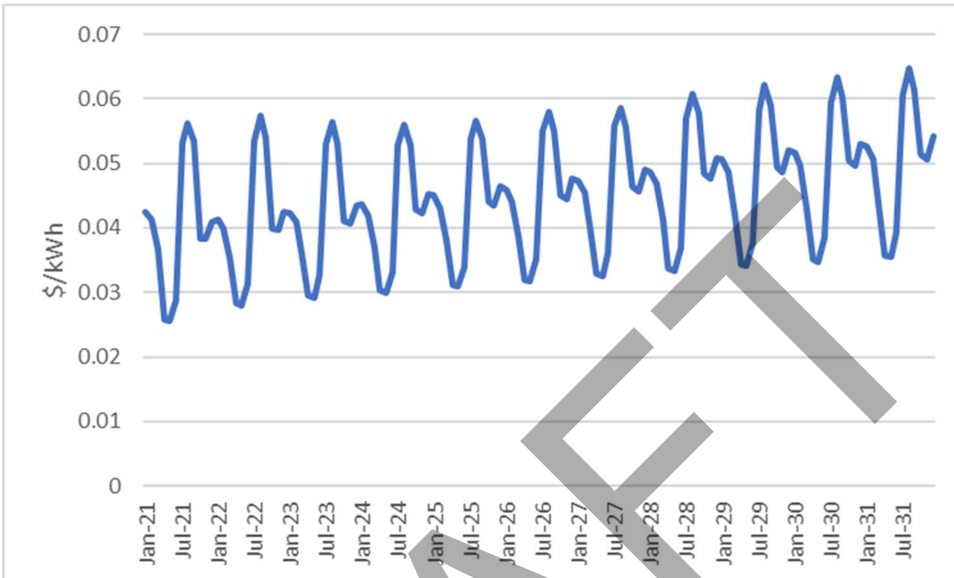
Projected Power Supply Costs

This Study presents the costs of renewable and non-renewable generating resources as well as power purchase agreements based on current and forecast wholesale market conditions, recently transacted power supply contracts, and a review of the applicable regulatory requirements. In summary, the 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 (expected) assumption for each of these cost categories as well as establishing a high and low range for each to be used for the sensitivity analysis later in the report.

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. Exhibit 7 shows forecast monthly southern California wholesale electric market prices. The levelized value of market purchase prices over the 10-year Study period is \$0.0411/kWh (2019\$).[12] Exhibit 7 shows the clear seasonal variability in prices each year, as well as the overall upward trend in prices.

Exhibit 7
Forecast 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.

Renewable Energy

The wholesale market prices shown above in Exhibit 7 are for non-renewable power (i.e., this product does not come with any renewable attributes). The cost of renewable resources varies greatly. Wind and solar levelized project costs vary from \$0.028 to \$0.060/kWh. Geothermal project costs can vary from \$0.070 to \$0.100/kWh. While geothermal projects have higher cost, they also have higher capacity factors than wind and solar projects and, as such, can bring additional value to the CCA as baseload resources. Geothermal resources also bring value from a resource adequacy perspective. The availability of geothermal, off-shore wind and ocean power in the marketplace is fairly minimal, so these resources were not included in this assessment of renewable energy market prices. Similarly, eligible renewable hydropower projects were not included in the renewable portfolio pricing as these projects are minimally

[12] Levelized prices over the study period consider projected prices discounted at a 4% rate. Levelizing is a form of averaging that considers the time value of the study period.

available. Once established, a CCA would conduct an integrated resource plan and issue requests for proposals for the resulting resources. These resources may include geothermal and eligible hydro projects depending on the resource plan results.

This Study assumes a renewable energy market price of $0.050/kWh for a blend of short-term and long-term wind and solar resource contracts, based on a survey of renewable resources currently in operation and new projects coming on-line. It is assumed that long-term renewable energy contract prices will be stable, at around $0.035/kWh, for the 20-year Study period to balance the influence of two trends. First, renewable energy prices are being driven down by the rapidly declining cost of solar and wind projects. This trend has persisted over the past several years and is expected to continue over the Study's forecast period. However, this trend is expected to be balanced out by the impact of increasing statewide demand for renewables as a result of California's renewable portfolio standards (RPS) laws and changes in Federal tax laws. These assumptions regarding renewable energy prices have been reflected in current market trends in southern California.

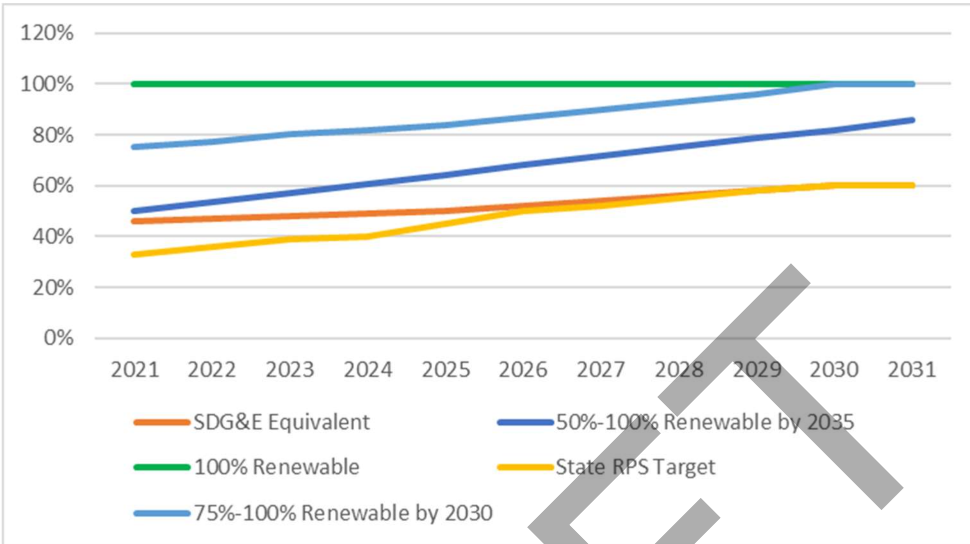
Per SB 100 and SB 350, RPS compliance requirements are 33% in 2020 and growing again to 60% in 2030. But, at a minimum, renewable energy procurement that matches SDG&E's plan is recommended. To provide information about the cost difference between renewable resource portfolios, this Study analyzes the following 4 portfolio scenarios:

1) **Scenario 1 - SDG&E-Equivalent Renewable:** Achieve between 46% and 59% renewables in 2021 through 2029, based on SDG&E planned renewable energy procurements. Achieve 60% renewables beginning in 2030.
2) **Scenario 2 - 50% Renewable at Launch, with 100% by 2035:** 50% of retail loads are served with RPS-qualifying renewable resources beginning in 2021, growing to 90% by 2030 and 100% in 2035 and after.
3) **Scenario 3 - 75% Renewable at Launch, with 100% by 2030:** 75% of retail loads are served with RPS-qualifying renewable resources beginning in 2021, growing to 80% by 2025 and 100% in 2030 and after.
4) **Scenario 4 - 100% Renewables Portfolio at Launch**: 100% of retail loads are served with RPS-qualifying renewable resources in all years.

The resource portfolios will be discussed in greater detail in the "Resource Portfolios" section below. It should be noted that the CCA policymakers (Partner JPA Board) may opt for other resource portfolios but those selected above should give the Partners a sound basis for evaluating other portfolio options.

The renewable energy targets of the four portfolios included in the power cost model are shown below in Exhibit 8. For comparison, the state RPS requirement is also presented in Exhibit 8. All power supply portfolios meet the RPS requirement outlined in SB 100 and SB 350. The SDG&E Portfolio is based on both current and forecast power content assuming SDG&E would sell excess RPS-qualifying resources in the event of significant load loss that would result should more cities within its service territory form CCAs.

Exhibit 8
Renewable Energy Purchase Scenarios Compared to the RPS Requirement[13]



Renewable Energy Credits (RECs)

In addition to direct purchases of renewable power, renewable energy credits (RECs) are an alternative for meeting RPS requirements. RECs are measured in MWh (energy = 1 MWh= 1 REC). These signify the renewable attributes of RPS-qualifying resource output. RECs undergo certification through WREGIS, a tracking system that determines for which Western states the RECs are qualified. RECS are transacted through WREGIS and retired as they are used to meet state RPS requirements.

Use of RECs are highly restricted and are not always the best alternative. California load serving entities (LSE)[14] must purchase bundled energy and/or RECs that meet certain eligibility requirements across three Portfolio Content Categories (PCC) or buckets. Each of the buckets represents a different type of renewable product that can be used to meet up to a specific percent of the total procurement obligation during a compliance period. The permitted percentage shares of each bucket type changes over time. The three buckets and the type of energy included in each bucket can be summarized as follows:

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

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

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

- **Bucket 2**: Renewable resources that cannot be delivered into a CBA without some substitution from non-renewable resources[15]. This process of substitution is referred to as "firming and shaping" the energy. The firmed and shaped energy is bundled with RECs.

- **Bucket 3**: Unbundled RECs, which are sold separately from the electric energy.[16]

Under the current guidelines,[17] the amount of RECs that can be procured through Buckets 2 and 3 is limited and decreases over time. SBX1 2 (April 2011) established a 33% RPS requirement for 2020 with certain procurement targets prior to 2020. SB350 (October 2015) increased the RPS requirement to 50% by 2030. Finally, in 2018, the RPS for 2030 was increased to 60% (SB100). The share of renewable power that can be sourced from Bucket 2 or 3 energy after 2020 is expected to be the same as the 2020 required share of total RPS procurement.[18] All power supply portfolios are modeled to meet the relevant state mandates. All load serving entities face the same mandates and resource choices.

Purchasing unbundled RECs from existing renewable resources does not increase the amount of renewable projects in the State. In addition, the REC market is not as liquid as it once was. For these reasons, this Study does not rely on unbundled REC purchases to meet renewable energy purchase requirements under the RPS.

However, in practice, small quantities of unbundled RECs may be used to balance the CCA's annual renewable energy purchase targets with the output from renewable resources. Due to the variable size and shape of the renewable energy purchases, the annual modeled renewable energy purchases do not typically match up perfectly with annual renewable energy purchase targets. In some years there are small REC surpluses, and, in others, there are small REC deficits. These surpluses and deficits can be balanced out using small unbundled REC purchases and sales. This methodology was used in order to simplify the modeling. In reality, small REC surpluses and deficits would most likely be handled by banking RECs between years. Unbundled REC prices are assumed to increase from $19.50/REC in 2020 to $24.86 in 2030 (2.5% annual escalation).

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[15] 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.

[16] 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.

[17] California Public Utility Code §399.16

[18] 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.

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 it is produced and, particularly with respect to renewables, can be intermittent, deliveries need to be firmed using ancillary services to meet the CCA's load requirements. Ancillary services and products need to be purchased from the CAISO based on the CCA's total loads requirement. Based on a survey of transmission congestion and ancillary service costs currently paid by CAISO participants, the ancillary service costs are estimated to be approximately $.003/kWh, escalating by 20% annually through 2026 and then at escalating by 5% annually for the rest of the study period. Ancillary service costs are expected to increase significantly as California works toward the RPS requirements over the next 10 years. The case where power supply costs are significantly higher due to ancillary cost escalation is explored in the risk assessment.

Resource Adequacy

In addition to purchasing power, the CCA would also need to demonstrate it has sufficient physical power supply capacity to meet its projected peak demand plus a 15% planning reserve margin. This requirement is in accordance with RA regulations administered by the CPUC, CAISO and the CEC. In addition, the CCA must meet the local and flexible resource adequacy requirements set by the CPUC, CAISO and CEC every year. The CPUC's resource adequacy standards applicable to a CCA require several procurement targets. CCAs must secure the following three types of capacity and make it available to the CAISO:

- System capacity is capacity from a resource that is qualified for use in meeting system peak demand and planning reserve margin requirements;
- Local capacity from a resource that is located within a Local Capacity Area and that is capable of contributing to the capacity requirement for that particular area; and
- 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 CPUC undertakes annual policy changes to the RA program, so these requirements may change by the time program launch occurs. Different types of resources have different capacity values for RA compliance purposes, and those values can change by month. Moreover, recent rule changes have reduced the RA values for wind and solar resources as more of these technologies are added to the system. As such, other types of renewables, including geothermal and biomass, could have an overall better value in the portfolio compared to relying on RA solely from gas-fired resources.

Power Management/Schedule Coordinator

Given the likely complexity of the 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 with 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 the 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.

The Partners' 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 the majority of 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 in the $0.0001 to $0.00025/kWh range for large operating CCAs. This Study very conservatively assumes a cost of $0.0005/kWh, escalating at 2.5% annually, in all portfolios as a starting cost. Over time, as the CCA is operating, it is expected that the scheduling costs will decline to the $0.0002/kWh range.

Resource Portfolios

Projected power supply costs were developed for four representative resource portfolios. Portfolios are defined by two variables:

(1) the share of renewable energy in the power mix (per the "Renewable Energy" discussion above), and
(2) the share of resources that are GHG-free in the power mix.

Renewable resources refer to resources that qualify under State and Federal RPS, such as solar and wind power. GHG-free power refers to energy sourced from any non-GHG emitting resource, including both the RPS-compliant sources mentioned above as well as nuclear power and large hydroelectric power. For this Study, no nuclear resources were included in the resource portfolio analysis.

SDG&E's resource portfolio in 2017 included 44% renewable energy resources, 39% natural gas resources as well as 17% unspecified (market) purchases. In 2017, SDG&E's resource portfolio was 44% GHG-free. As the amount of load served by renewable resources increases each year, so too would the amount of load served by GHG-free resources.

In each of the portfolio scenarios the share of GHG-free energy is equal to the share of eligible renewable power content. When a 100% renewable portfolio is assessed, market transactions for energy are required to balance load. In these cases where non-renewable energy is purchased at the market, the CCA pays a premium for market Power Purchase Agreements (PPAs) sourced to GHG-free resources. A calendar year 2020[19] GHG-free premium of $0.004/kWh was assumed based on a survey of other CCA GHG-free energy purchases. The GHG-free premium is assumed to escalate annually by 5%. Given the assumed escalation rate, the premium paid for GHG-free power increases from $0.004/kWh in 2020 to $0.01/kWh in 2030.

Resource Options

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

[19] Forecasts may have different base years, in the analysis all costs are escalated to begin in 2021.

Exhibit 9 shows the 20-year levelized resource costs used in this Study. It compares the costs of wholesale market power prices, a PPA tied to the wholesale market power prices, and the four portfolios evaluated in the Study.

Exhibit 9
20-Year Base Case Levelized Resource Costs
(2018 $/kWh)

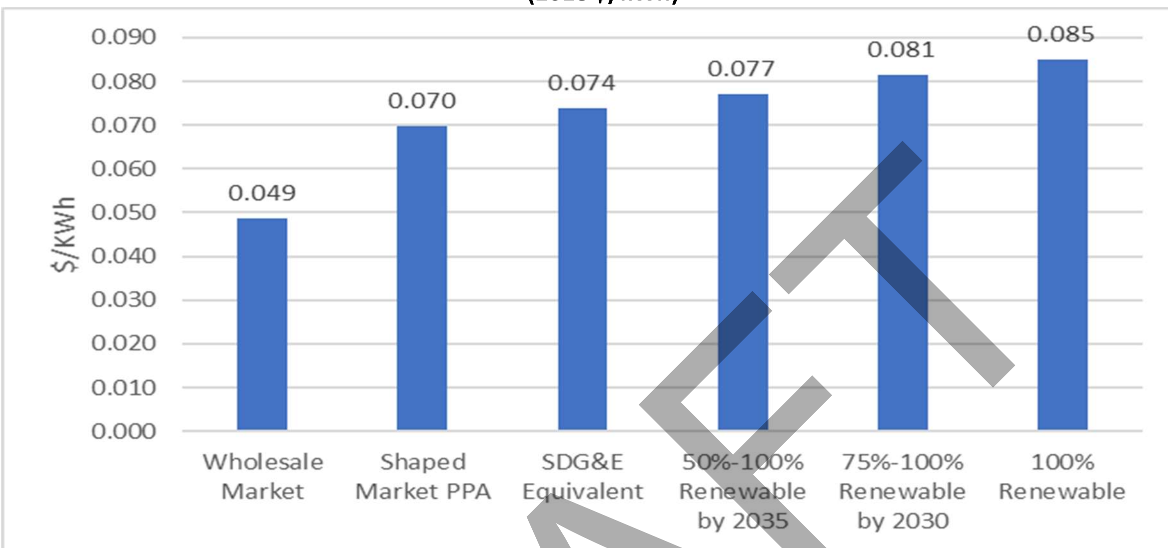


Exhibit 9 above shows a 20-year levelized price of near $0.074/kWh under the SDG&E Equivalent Renewable, about $0.077/kWh for Scenario 2 - 50% to 100% Renewable by 2035 Portfolio, near $0.081/kWh for Scenario 3 - 75% to 100% by 2030 Portfolio, and a price of near $0.085/kWh under Scenario 4 - 100% Renewable Portfolio. The higher price in Scenario 4 - 100% Renewable Portfolio is in recognition of the fact that the CCA may have to sign contracts for higher priced renewables in order to find a sufficient supply of renewables to meet the higher targets. The levelized resource costs shown above are for power only and do not include any ancillary services, scheduling or other costs.

Exhibit 9 also shows both spot wholesale market cost at $0.049 per kWh and market PPA cost at $0.07 per kWh. Market PPA costs are greater than spot wholesale market costs in recognition of the cost of the PPA supplier absorbing the market fuel price risk associated with providing a long-term PPA contract price.

The capacity factor for market PPA purchases is assumed to be 100% (flat monthly blocks of power). Capacity factor is equal to average monthly generation divided by maximum hourly generation in a given month. A 100% capacity factor implies that the same amount of power was purchased or generated each hour. The average monthly capacity factor for renewable resources and local renewables is assumed to be 33% based on the capacity factors of existing renewable resources operating in California.[20]

[20] Wind resource capacity factors for new projects range from 28-40%, Solar capacity factors average 50% annually.

On a $/watt basis, the cost of smaller scale solar projects is greater than the cost of large-scale solar projects. It is expected that the cost of smaller local renewable resources is $0.065/kWh based on information related to recent projects. The advantage of local renewable projects is lower transmission costs, less transmission loss, and less stress on the congested transmission grid.

The renewable energy requirements in the State's RPS are based on retail energy sales. Retail energy refers to the amount of energy sold to customers as opposed to the amount of energy purchased from generation sources (wholesale energy). Wholesale energy purchases must always exceed retail energy sales to account for transmission and distribution system losses. To be consistent, it was assumed that the renewable energy targets included in the portfolios apply to retail energy sales.

Renewable PPA Pricing

Short-Term Renewable Energy Contract Price

Short-term contracts have a term of one to three 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). The Study's assumes that RECs are priced at $19.50/REC for bucket 1 RECs and $7.75/REC for bucket 2 RECs (1 REC = 1 MWh). Bucket 1 were assumed to escalate at 2.4 percent annually and bucket 2 REC prices were assumed to escalate at 5.75 percent annually. The forecast also assumes that 75 percent of RECs acquired under short-term renewable contracts were bucket 1 RECs. Given these assumptions, the short-term renewable contract price escalated from $56/MWh in 2021 to $65/MWh by 2030. This pricing is used for short-term renewable energy contracts in all cases in this study.

Long-Term Renewable Energy Contract Price

The Study includes a long-term renewable PPA fixed contract price of $35/MWh (all years) based on recent transactions. The $35/MWh assumption is conservative as other CCAs are currently signing PPAs with flat contract prices in the range of $28-$32/MWh for solar and wind respectively.

The power supply costs are based on 65% of the RPS requirement purchased via the lower-cost long-term contracts beginning in 2021 to meet SB 350 requirements. As the CCA continues to operate, it is assumed that the share of the lower-cost contracts would increase over time to 75% by 2030.

Scenario 1: SDG&E-Equivalent Renewable Portfolio

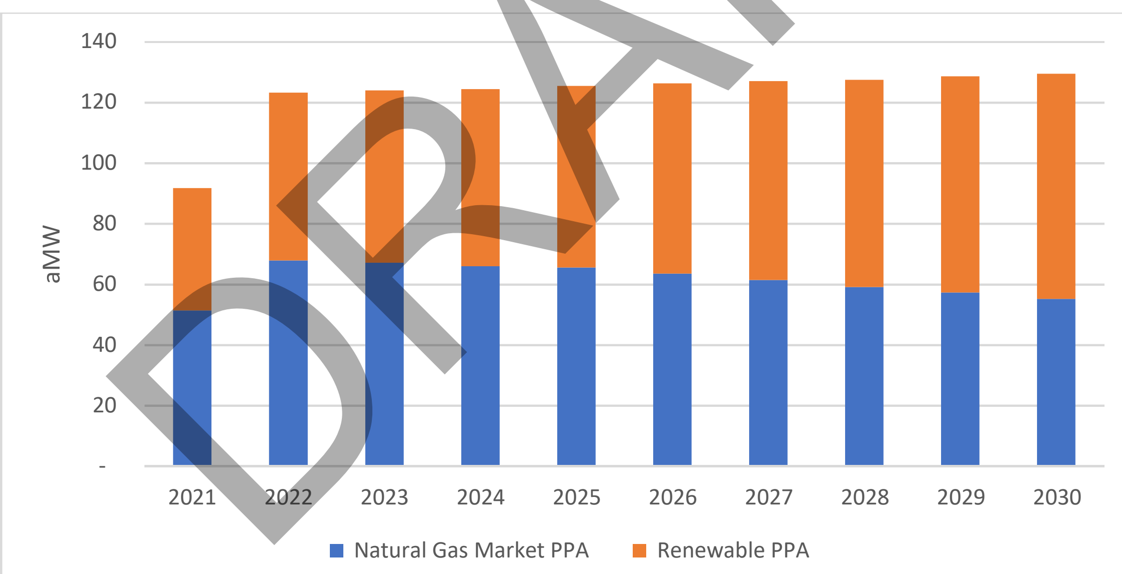
In this portfolio, the renewable energy purchases match the expected SDG&E renewable share based on recent information.[21]

For energy requirements in excess of the CCA's renewable energy requirement or goal, market purchases are made. For this Study's purposes, market purchases are assumed to be sourced from non-renewable generating facilities which are most likely natural gas resources. In reality the market purchases might be from several resources including renewable energy.

The Renewable PPA energy is the sum of all short-term and long term PPA purchases. In addition, this category may also include market purchases plus the GHG-free premium (large hydropower) plus Bucket 2 RECs. This last type of purchase is reserved for energy balancing only as it is assumed most of the renewable energy requirement or goals are met through specific renewable contracts.

In Exhibit 10, the orange bars show renewable energy purchases (46% to 60%). Renewable energy purchases in 2021 through 2023 are greater than the RPS minimum requirement of 33%. Note that loads during the first year of operation are lower due to an April start date. The first full year of CCA service is 2022.

Exhibit 10
Scenario 1: SDG&E-Equivalent Renewables Portfolio (aMW)



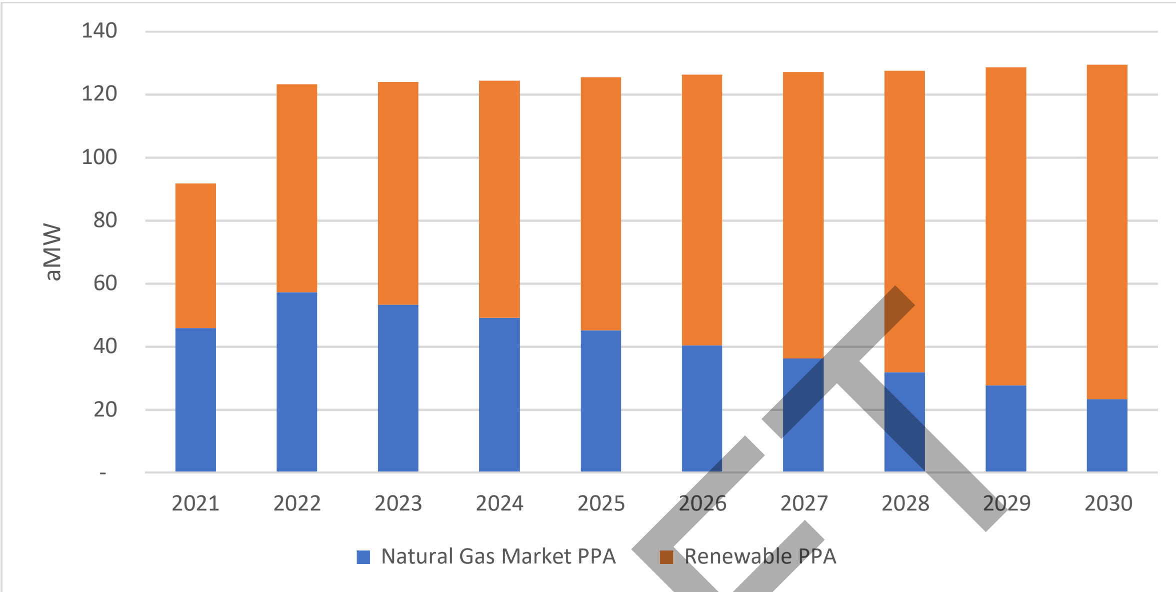
*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

Scenario 2: 50% Renewable at Launch to 100% Renewable by 2035 Portfolio

In this portfolio, a minimum of 50% of retail load is served by renewable resources beginning in 2021 growing to 86% through 2030 and 100% by 2035. Exhibit 11 illustrates this portfolio.

[21] http://www.energy.ca.gov/pcl/labels/2017_index.html

Exhibit 11
Scenario 2: 50% Renewable at Launch to 100% Renewable by 2035 Portfolio (aMW)

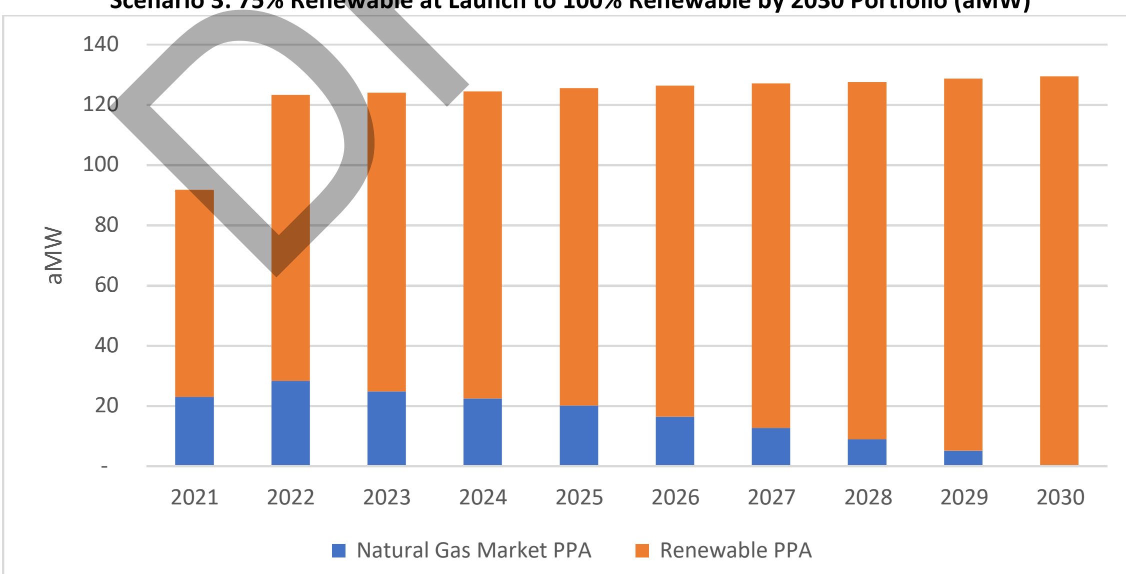


*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

Scenario 3: 75% Renewable at Launch to 100% Renewable by 2030 Portfolio

In this portfolio, a minimum of 75% of retail load is served by renewable resources beginning in 2021 growing to 84% through 2025 and 100% by 2030. Exhibit 12 illustrates this portfolio.

Exhibit 12
Scenario 3: 75% Renewable at Launch to 100% Renewable by 2030 Portfolio (aMW)

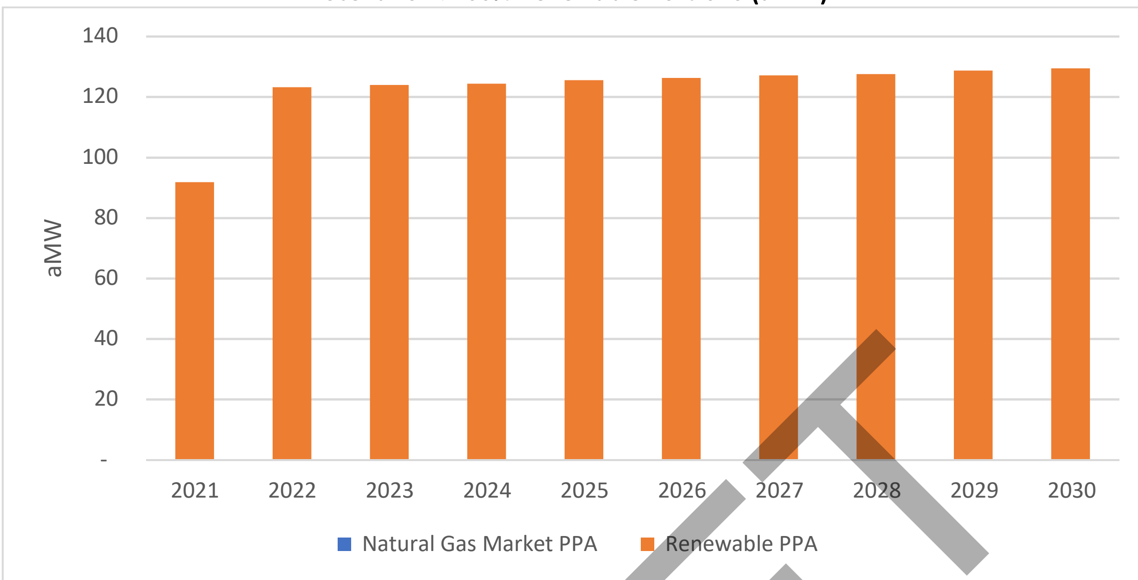


*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

Scenario 4: 100% Renewable Portfolio

In this portfolio, 100% of retail load is served by renewable resources in all years. As shown below in Exhibit 13 renewable energy purchases are the majority of the portfolio where market PPAs and GHG-Free Market PPAs are used only for load following.

Exhibit 13
Scenario 4: 100% Renewable Portfolio (aMW)

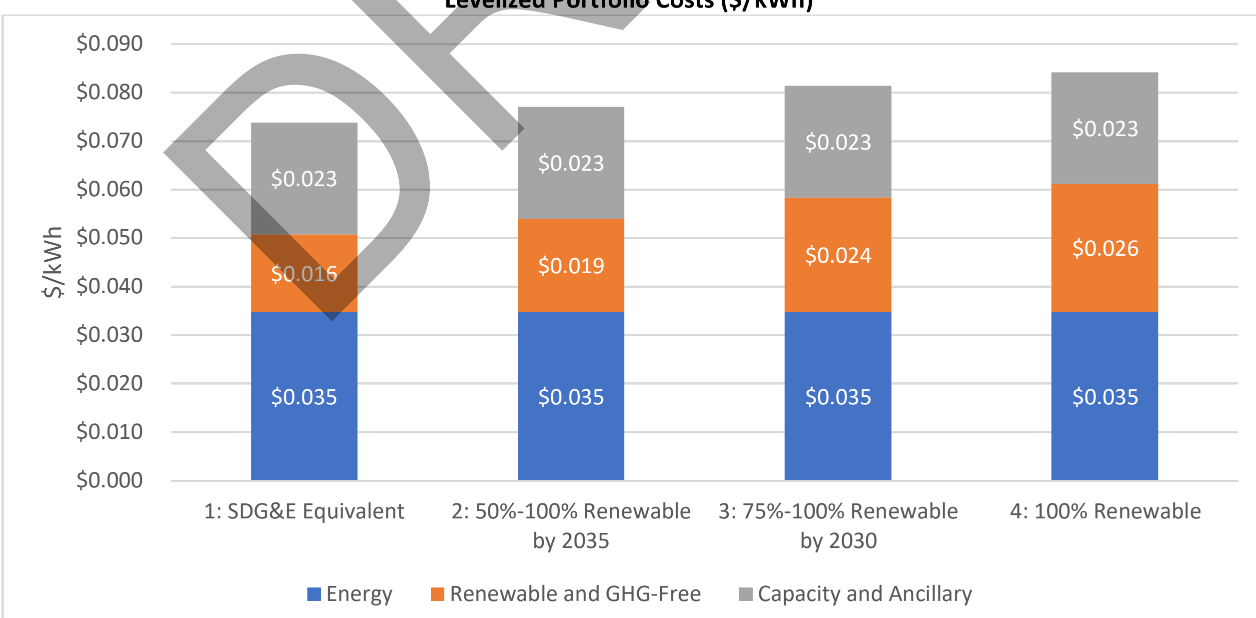


*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

20-Year Levelized Portfolio Costs

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

Exhibit 14
Levelized Portfolio Costs ($/kWh)



As shown above, power costs under the four portfolios considered are fairly similar except for the 100% renewable portfolio. There is not a large variance in power costs between these portfolios because the majority of power is supplied by market PPAs and renewable energy purchases, which are very close in cost.

Resource Strategy

The Partners' electric portfolio may be managed by a third-party vendor, at least during the initial implementation period. Through a power services agreement, the Partners can obtain full service requirements electricity for its customers, including providing for all electric, ancillary services and the scheduling arrangements necessary to provide delivered electricity.

After operations have begun, the Partners could decide to sign long-term PPAs, which could minimize the CCAs exposure to market prices and provide the CCA with the ability to increase the renewable percentage over time. Additionally, it is recommended that the Partners 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.[22] The decision requires that contracts be in place by 2020 and projects be installed by 2024. The feasibility study assumes storage projects would be funded from New Programs funds. Due to the start-up nature of the Partner's CCA program it is assumed that storage projects will be contracted with by the end of 2021.[23] Additionally, the Partner CCA would need to procure 65% of the RPS requirement via long-term contracts of 10 or more years.

[22] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K912/78912194.PDF

[23] Based on incremental storage project costs ranging from $10 to $80/kWh, the cost to meet this requirement is estimated in the range of $25,000 to $400,000 per year for the Partners together.

May 2017, NextEra Energy entered into a 20-year PPA with Tucson Electric Power to finance a 100 MW solar array paired with a 30 MW/120 MWh energy storage system—the agreed-upon price was $45/MWh. In December 2017, Xcel Energy's Colorado utility subsidiary announced the results of a recent solicitation where the median bid price for solar-plus-storage projects was $36/MWh and the median bid price for wind-plus-storage projects was $21/MWh. https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

Cost of Service

This section of the Study describes the financial pro forma analysis and cost of service for a CCA for the Partners. 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.

Cost of Service for Partners CCA Operations

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

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

Once the costs of CCA operations have been determined, the total costs can be compared to SDG&E's projected rates. A detail of the various non-power supply costs is included in Appendix C.

Power Supply Costs

A key element of the cost of service analysis is the assumption that electricity would be procured under a power purchase agreement (PPA) for both renewable and non-renewable power for an initial period. Power supply would likely be obtained by the CCA's procurement consultant prior to commencing operations. The products and services required from the third-party procurement consultant are energy, capacity (System, Local and Flexible RA products), renewable energy, GHG-free energy, load forecasting, CAISO charges (grid management and congestion), and scheduling coordination.

The calculated 20 year levelized cost of electric power supply, including the cost of the scheduling coordinator and all regulatory power requirements, is estimated between $0.075 and $0.082 per kWh as discussed in the previous chapter. This price represents the price needed to meet the load requirements of the CCA customers while meeting required regulations (SB 350 and SB 100) and objectives of the CCA. The variation in price is a function of the desired level of renewable resources.

Three power supply scenarios are modeled for this Study have been discussed in previous sections. As a reminder the scenarios are:

(1) SDG&E Renewable Equivalent
(2) 50% Renewable at Launch and 100% Renewable by 2035
(3) 75% Renewable at Launch and 100% Renewable by 2030
(4) 100% Renewable

Non-Power Supply Costs

While power supply costs would make up the vast majority of costs associated with operating a Partners CCA (roughly 90-95% depending on the portfolio scenario), there are additional cost components that must be considered in the pro forma financial analysis. These additional non-power supply costs are summarized in Exhibit 15 and then described below.

Exhibit 15 2021 Non-Power Supply Costs and Reserves $millions	
Staffing	$ 1.61
General & Administrative Expenses	$ 0.22
Consulting Services	$ 1.17
Billing & Data Management	$ 1.56
SDG&E Fees	$ 0.63
Uncollectible	$ 0.11
Financial Reserves	$10.90
Debt Service	$ 2.10
Total	$18.30

Estimated Staffing Costs

Staffing is a key component of operating a CCA. This Study assumes the Partners will proceed with the JPA operating model. All staffing costs for the Partner CCA are shown in Exhibit 16.

The Partners' CCA would have discretion to distribute operational and administrative tasks between internal staff and external consultants in any combination. For this Study, a full staffing scenario is modeled in the analysis. A minimum staff scenario would rely on a few dedicated staff members and the use of technical consultants for support. If the CCA finds that there are cost savings for a minimal staff organization, the results of the feasibility would improve. The staffing assumptions are provided below.

Full Staff Scenario

Exhibit 16 provides the estimated staffing budgets for a full staff CCA scenario for the start-up period (Pre-launch in 2020 through full operating in 2021). Staffing budgets include direct salaries and benefits. Prior to program launch, it is assumed that an operating team would be employed per the example of other CCAs in California thus far to implement the launch of a CCA program. This operating team typically includes an Executive Director, a Director of Administration and Finance, a Communication Outreach Manager and a Director of Power Resources. The remaining functions would be filled as quickly as possible.

Exhibit 16
CCA Staffing Plan

CCA Staff Positions	2021 Launch*	2022
Executive Director	1	1
Director of Marketing and Public Affairs	1	1
Account Service Manager	1	1
Account Representative	1	1
Communication Outreach Manager	1	1
Communication Specialist	1	1
Director of Power Resources	1	1
Power Resource Analyst	1	1
Power Supply Compliance Specialist	1	1
Administrative Assistant	1	1
Total Number of Employees	**10**	**10**
Total Staffing Costs	$1,613,000	$1,892,000

*Represents only partial operating year (April through December).

Based on this staffing plan, the Partners' CCA would initially employ four staff members. Once the CCA launches, it is anticipated that staffing would increase to approximately 10 employees within the first year of operation. It should be noted that if the Partners choose to join the Regional CCA, there would likely be some economies of scale savings for overhead such as staffing. A large CCA program such as the City of San Diego or Clean Power Alliance typically has at least 20 full time employees.[24] Even with a greater number of dedicated staff, the administration costs on a $/kWh basis are expected to further decrease the CCA rates from a 2% discount to a 3% discount off the forecast SDG&E rates.

[24] City of San Diego Business Plan

General and Administrative Costs

Overhead needed to support the organization includes computers and other equipment, office furnishings, office space, utilities and miscellaneous expenses. These expenses are estimated at $28,000 during program pre-start-up. Office space and utilities are ongoing monthly expenses that would begin to accrue before revenues from program operations commence, and are; therefore, included in start-up costs that would be financed.

It is estimated that the per employee start-up cost is approximately $10,000. This expense covers computer and furniture needs. An additional annual expense of $55,080 for office space, and approximately $10,000 per year in office supplies and utilities costs is expected. Miscellaneous start-up costs of $62,000 are estimated for 2021 to address the general cost of mailing notifications, meetings, communication and other start-up activities. In addition, it is assumed that computers would need to be replaced every 5 years. All administrative costs for start-up are shown in Exhibit 17. These costs are based on other start-up CCA operations. These costs are a very small portion of total operating costs that even a doubling of these costs from the below assumptions would not change the Study findings.

Exhibit 17

Estimated Overhead Cost by Year (Full-Staff Scenario)

	2021	2022
Infrastructure Costs		
Computers	$51,000	$0
Furnishings	$51,000	$0
Office Space	$55,080	$74,909
Utilities/Other Office Supplies	$0	$0
Miscellaneous Expenses	$62,883	$85,521
Total Infrastructure Costs	**$219,963**	**$160,430**

The above costs are based on a full staff scenario. If the CCA determines in its business plan that hiring consultants rather than staff would be more cost-effective administrative costs would be reduced improving the feasibility of the CCA.

Outside Consultant Costs

Consultant costs would include outside assistance for legal and regulatory work, communication and marketing, data management, financial consulting, technical consulting and implementation support.

CCA data management providers supply customer management system software, and oversee customer enrollment, customer service, as well as the payment processing, accounts receivable and verification services. The cost of data management is charged on a per customer basis and has been estimated based on existing contracts for similar sized CCAs. For this Study, the cost for data management is estimated at $1.25 per customer per month.

In addition, estimated funding for other consulting support (such as HR, legal, customer service, etc.) is provided. These costs have been estimated based on the experience of start-up consulting costs at other CCAs. Exhibit 18 shows the estimated consultant costs except for data management during the first 2 years. Consultant fees are provided on a monthly and annual basis in Appendix C.

Exhibit 18
Estimated Consultant Costs by Year
April 2021 Launch

	2021	2022
Legal/Regulatory*	$76,500	$104,040
Communication	153,000	208,080
Financial Consulting**	191,250	260,100
Scheduling Consultant	466,500	634,440
Data Management	1,556,196	2,168,572
Other Consulting/City Functions	283,050	541,008
Total Consultant Costs	**$2,726,496**	**$3,916,240**

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

The estimate for each of the services is based on costs experienced by other CCAs. Consultant costs are increased by inflation every year.

SDG&E Fees

SDG&E would provide billing and metering services to the CCA based on Schedule CCA: Transportation of Electric Power to CCA Customers. The estimated costs payable to SDG&E for services related to the Partners' 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.

Customers who choose to receive service from the CCA would be automatically enrolled in the program and have 60 days from the date of enrollment to opt-out of the program. A total of four opt-out notices would be sent to each customer. The first notice would be mailed to customers approximately 60 days prior to the date of automatic enrollment. A second notice would be sent approximately 30 days later. Following automatic enrollment, two additional opt-out notices would be provided within the 60-day period following customer enrollment.

Based on SDG&E's current rate schedules, and CCA participation assumptions, SDG&E billing charges would be approximately $376,000 annually and initial setup costs and noticing would be on the order of $360,000 for 2021, as shown in Exhibit 19.

Exhibit 19 Utility Transaction Fees		
	2021	2022
SDG&E Billing Fee	$268,520	$374,185
Setup costs	$358,787	$0

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 funds, approximately 0.2% of revenues are estimated as uncollectible.[25] This cost is therefore included in the CCA operating costs, or expense budget.

Financial Reserves

The Partners' CCA is assumed to receive capital financing during its start-up through full operation. After a successful launch, the CCA must build up a reserve fund that is available to address contingencies, cost uncertainties, rate stabilization or other risk factors faced by the CCA. Therefore, this Study assumes that the 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 three months of expenses. This level of reserves represents the *minimum* 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 finance a rate stabilization fund, new local renewable resources, economic development projects and/or lower rates. Exhibit 20 provides the estimate of the reserves available for local programs or rate stabilization.

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

Exhibit 20 Estimated Reserves: Scenario 2: 50% Renewable at Launch to 100% Renewable by 2035 Assuming 2% Rate Discount Off SDG&E Rates			
	Cumulative Surplus*	Operating Reserves (4 months O&M)	Programs or Rate Reduction
2021	$924,519	$17,231,458	$0
2022	$6,176,982	$24,410,008	$0
2023	$11,156,864	$25,047,569	$0
2024	$15,214,904	$26,115,800	$0
2025	$25,276,403	$26,839,687	$4,162,439
2026	$37,836,060	$26,908,797	$12,559,657
2027	$51,439,869	$27,680,778	$13,603,809
2028	$65,892,839	$28,446,049	$14,452,970
2029	$81,153,618	$29,253,637	$15,260,779
2030	$97,810,994	$30,099,670	$16,657,376
2031	$115,142,951	$31,113,964	$17,331,957

* Includes cash from financing

The new program funding remains stable over the study period. The financial reserves are documented in Appendix B.

Financing Costs

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

Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that 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 July 2020. In general, the components of the cash flow analysis can be summarized into two distinct categories:

1. Cost of the CCA operations, and
2. Revenues from CCA operations.

The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with the CCA and specifically account for the transition or "phase-in" of the CCA customers.

The cash flow analysis also provides estimates for revenues generated from the Partner CCA operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes all customers are enrolled at the same time, based on the assumed participation rates, and assumes that the CCA offers rates that provide a discount compared to projected SDG&E rates corresponding to a total bill discount of 2% for each customer class.

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.

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. Some customer payments are received well after the due date. Therefore, the 30-day net lag in payment is 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 CPUC Bond of minimum $180,000[26] and a potential SDG&E program reserve. While the CCA may be able to utilize a line of credit, for this Study it is assumed that this working capital requirement is included in the financing associated with start-up funding. The Study finds that the CCA will need as much as $12 Million in working capital.

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] At initial launch MCE served electrical load roughly equivalent to 80-90% of the Partner CCA's estimated load.[29] Similarly, Sonoma Clean Power (SCP) acquired $6.2 million in pre-launch capital,[30] and now maintains working capital reserves of $25 million[31] while serving 25% more than the Partner CCA's estimated load.[32] The working capital needs after launch assumed in this Study are reflective of the experience of successfully operating CCAs on a $/GWh basis.

[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

[29] https://www.mcecleanenergy.org/wp-content/uploads/2016/01/Marin-Clean-Energy-2015-Integrated-Resource-Plan_FINAL-BOARD-APPROVED.pdf

[30] https://sonomacleanpower.org/wp-content/uploads/2015/01/2014-SCPA-Audited-Financials.pdf

[31] https://sonomacleanpower.org/wp-content/uploads/2015/01/2016-05-SCP-Compiled-Financial-Statements.pdf

[32] https://sonomacleanpower.org/wp-content/uploads/2015/01/2015-SCP-Implementation-Plan.pdf

Total Financing Requirements

The start-up of the Partners' CCA would require a significant 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.

Staffing, consultant and other program initiation costs have been discussed previously. In addition, the Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to 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, which are $1.12/customer for 2018. 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.

For the Partners' CCA, the total financing requirement, including working capital, is $12 million.

Current CCA Funding Landscape

The CCA market is rapidly expanding with increasingly proven success. To date, there are twenty operational CCAs in California and existing CCAs have demonstrated the ability to generate positive operating results. The early sources of 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 looking for financing. As such, the Partners 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 and those in development have relied on a sponsoring entity to provide support for obtaining needed funds. This support has come in varied forms, which are summarized in Exhibit 21.

Exhibit 21 Forms of Support			
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 has also 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 Clean Energy	2018	N/A	Vendor Funding
East Bay Clean Energy	2018	$50 million	Revolving Line of Credit from Barclays.

[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:

Direct Loan from Cities – Any of the Partner cities could loan funds from its General Fund for all or a portion of the pre-launch through launch needs. Start-up funding provided by the cities would be secured by the CCA revenues once launched. The cities would likely assess a risk-appropriate rate for such a loan. This rate is estimated to be 4.0% to 6.0% per annum.

Collateral Arrangement from Cities – As an alternative to a direct loan from the cities, the cities 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 cities obligations would be secured by CCA revenues collected once the CCA achieves viability.

Loan from a Financial Institution without Support – Silicon Valley Clean Energy Authority (SVCEA) was able to use this option to fund ongoing working capital. After 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 options used by emerging CCAs. This arrangement 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 held by the CCA.

Vendor Funding – The CCA could negotiate with its power suppliers 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. This method was used by Solana Energy Alliance.

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

CCA Financing Plan

While there are many options available to the CCA for financing, the initial start-up funding is expected to be provided via short-term financing via 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 capital requirements for the Partners’ CCA through launch are approximately $0.6 million. 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 $10 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 Appendix D.

Rate Comparison

This section provides a comparison of rates between SDG&E and the Partners' 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.

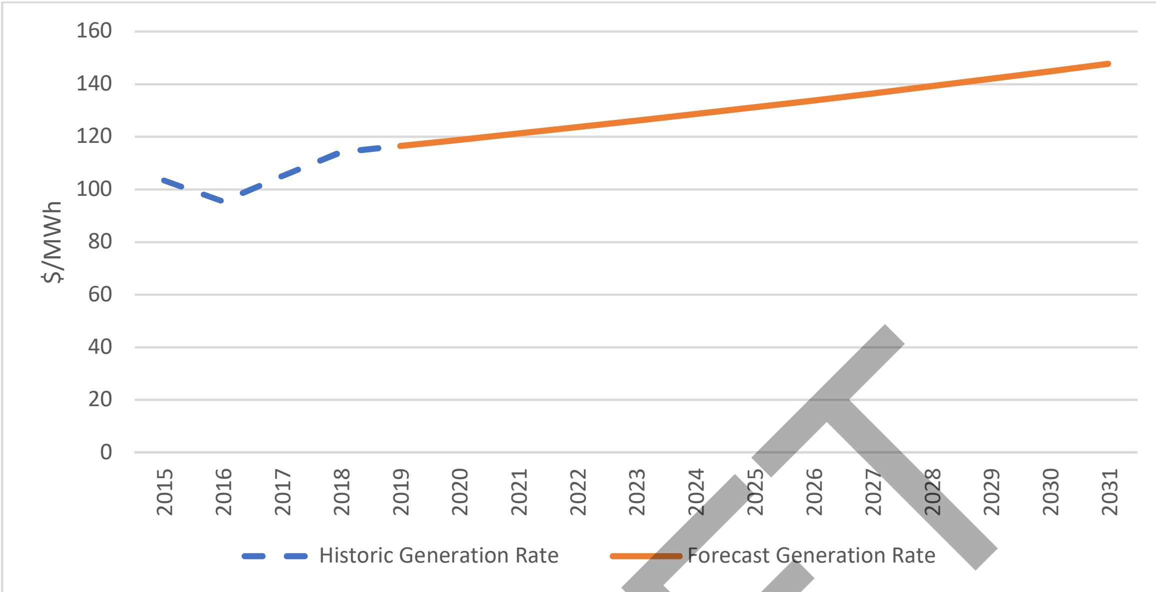
Rates Paid by SDG&E Bundled Customers

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 the Partners' 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, which include time-of-use rates. 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 based on the renewable and non-renewable market price forecast, and the state's regulatory requirement for RPS, energy storage, and resource adequacy objectives. It is projected that SDG&E-owned resource and renewable cost escalation will be 2% over the 10-year analysis period. SDG&E does not provide detailed cost information or power supply price forecasts for the utility. Based on SDG&E's 2017 resource mix and RPS requirements, 50% to 60% of SDG&E's resources come from market purchases and natural gas resources for which costs grow based on market price changes. Market costs are expected to increase at a rate of 1% to 3% annually. The remainder of SDG&E's resources are from high priced long-term renewable contracts. While the cost of market purchases and natural gas are expected to increase, the cost of the renewable portfolio is expected to decrease over time as SDG&E's current contracts expire and new lower cost renewable contracts are obtained. The Study uses a conservative 2% growth rate for SDG&E generation costs beginning in 2021. This growth rate is conservative compared with the growth rate utilized in the City of San Diego Feasibility Study (roughly 2.5%). The SDG&E generation rate forecast can be seen in Exhibit 22.

Exhibit 22
SDG&E Average Generation Rate, $/MWh



Rates Paid by CCA Customers

The Study assumes that the Partner CCA's 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 also referred to as the Cost Responsibility Surcharge (CRS). The CRS is comprised of the following components: 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 charges payable to SDG&E by the Partners' CCA customers only is the PCIA.

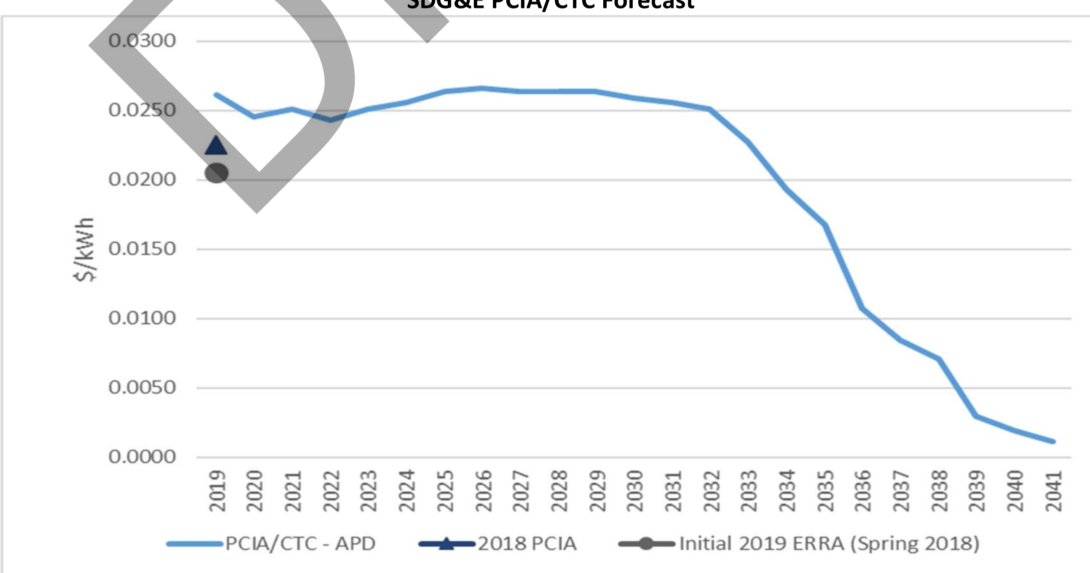
Power Charge Indifference Adjustment

The PCIA is an exit fee that is added to CCA rates to cover an IOU's stranded costs associated with energy purchases made to anticipated, but unrealized, demand because of customers leaving bundled service to receive service from a CCA.

On October 11, 2018 the CPUC voted unanimously to revise the PCIA methodology adopting the Alternative Proposed Decision (APD) methodology. This new methodology allows for more utility-owned resources to be included in the calculation and gets rid of the limits on cost recovery previously embedded in the old PCIA methodology. In addition, the new methodology allows for reductions in the stranded cost due to the value of renewable energy and resource adequacy provided by the resources. The APD methodology is not completely final as a Phase 2 is underway. Phase 2 will define the methodologies for defining additional components of the APD methodology such as resource adequacy value in IOU portfolios, value of renewable energy, true-up, and prepayment. Phase 2 decisions will be finalized late 2019 early 2020. The forecast below incorporates the latest decision, market conditions, and forecast stranded costs for departing SDG&E customers as seen in Exhibit 23.

As the chart shows, the PCIA drops significantly in the later years as SDG&E's existing power supply contracts and resources expire. If the Partners were to delay launching a CCA program for a year or two, the delay will not likely impact the duration of the higher PCIA values. Since SDG&E purchases power through long-term contracts, it would continue to purchase power for the Partners loads until formal notice of intent is given by the Partners. Therefore, SDG&E may purchase power via 10-year or longer contracts between now and when the Partners give notice. Therefore, delaying CCA implementation is not likely to benefit the CCA program with regard to PCIA rates.

Exhibit 23
SDG&E PCIA/CTC Forecast

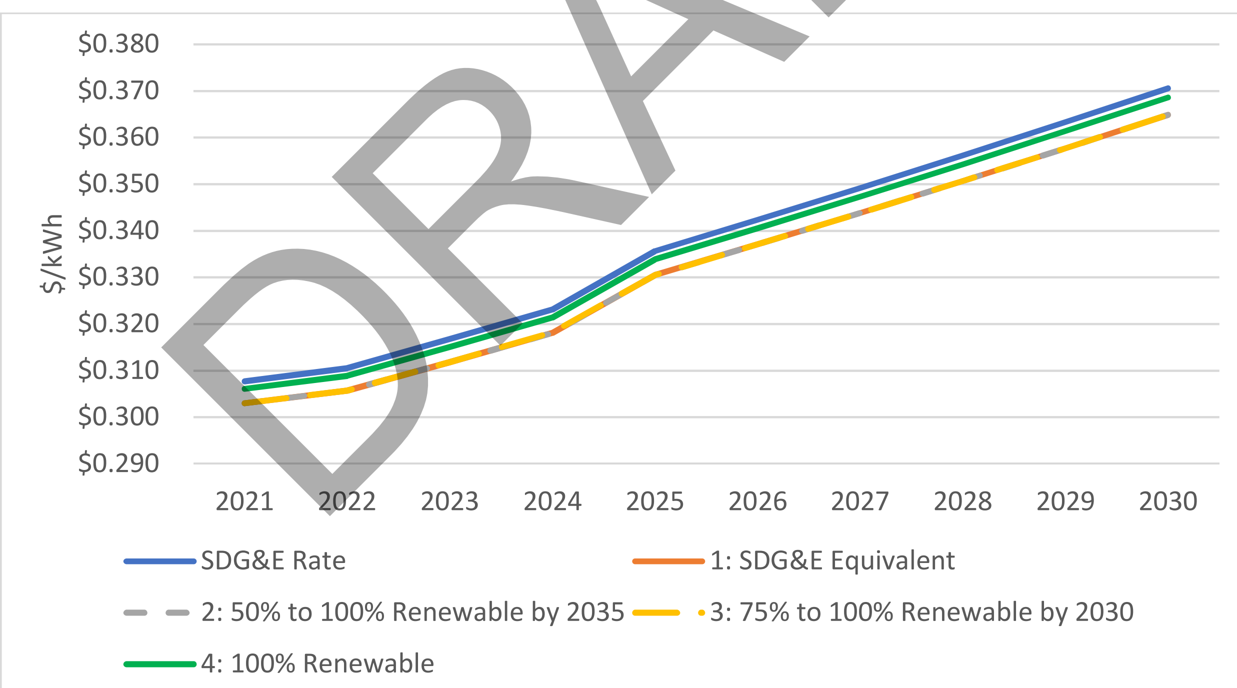


Retail Rate Comparison

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 3-4 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.

The rate forecasts are illustrated below in Exhibit 24. A rate discount of 2% is targeted for the SDG&E-Equivalent Renewable Portfolio, 50% to 100% Renewable by 2035, and the 75% to 100% Renewable by 2030; therefore, those rates are equivalent in Exhibit 27. The 100% Renewable Portfolio rates are calibrated to a 1% discount of SDG&E rates while collecting the reserves needed for CCA operation. Exhibit 28 shows that the CCA could potentially offer 100% renewable energy at rate slightly lower to SDG&E.

Exhibit 24
Average Total Retail Rate Comparison – With Savings Targets



Based on estimated CCA discounts, Exhibit 25 provides a comparison of the indicative bundled rates for CCA products based on the projected 2021 SDG&E rates. These indicative rates are calculated as a percentage off SDG&E's bundled rates. The CCA rates calculated in this Study are for comparison purposes only. Under formal operations, the CCA policymakers would determine the actual rates offered to its customers.

Exhibit 25
Rate Comparisons, Total Bill $/kWh

Rate Class	2021 SDG&E *	1: SDG&E Equivalent Renewable	2: 50% to 100% Renewable by 2035	3: 75% to 100% Renewable by 2030	4: 100% Renewable
Residential	0.3576	0.3504	0.3504	0.3504	0.3540
Commercial & Industrial	0.2491	0.2442	0.2442	0.2442	0.2467
Lighting	0.1804	0.1768	0.1768	0.1768	0.1786
Agricultural	0.1240	0.1215	0.1215	0.1215	0.1228
Total	**0.3077**	**0.3016**	**0.3016**	**0.3016**	**0.3046**
Bill Savings		**2.00%**	**2.00%**	**2.00%**	**1.00%**

*SDG&E bundled average rate projections based on SDG&E's 2019 Rates. Includes current time-of-use rate structure.

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

Environmental and Economic Impacts

This section provides an overview of the potential environmental and indirect economic impacts to the San Diego area from the implementation of a CCA in the three Cities. In addition, potential future programs that could be offered by the CCA are outlined.

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

At this time, SDG&E's resource mix is 44%[33] GHG-free due to power supply from renewable resources. The passing of SB100 accelerates the Renewable Portfolio Standard (RPS) obligations for retail sellers (investor-owned utilities (IOUs), CCAs, energy service providers (ESPs), and Public Owned Utilities (POUs)) as follows:

a) from 40% to 44% by 2024;
b) from 45%t to 52% by 2027; and
c) From 50% to 60% by 2030.

The bill also establishes state policy that RPS-eligible and zero-carbon (Clean Energy) resources supply 100% of all retail sales of electricity to California end-use customers no later than December 31, 2045. SDG&E is therefore expected to be 60% renewable and GHG free by 2030 and 100% GHG-free by 2045.

As outlined in the Resource Portfolio section above, the CCA portfolio scenarios assumed that the CCA's renewable resources determine the GHG-free content in the portfolio. In the Scenario 1 - SDG&E-Equivalent, it is assumed that the Partners' CCA resource portfolio is 46% GHG-free in 2021 and grows to 60% GHG free by 2030. In Scenario 2 - 50% to 100% Renewable By 2035 it is assumed that the CCA's resource portfolio is 50% GHG-free in 2021 and that the GHG-free resources increase each year after 2021, in 2030 GHG-free resources are 86% and continue to grow to 100% by 2035. In Scenario 3 - 75% to 100% Renewable By 2030 it is assumed that the CCA's resource portfolio is 75% GHG-free in 2021 and grows to 100% GHG-free by 2030. Finally, in Scenario 4 - 100% Renewable, 100% of the portfolio is GHG free in all years.

The remaining energy would generate amounts of GHG emissions as outlined in Exhibit 26. For comparison with SDG&E's projected portfolio, the 10-year average for GHG-free power is used (53%). The 10-year average recognizes the higher GHG-free power content in SDG&E's projected portfolio in later years. Average annual emissions from the four portfolios for 2021-2030 are presented below. In each case, it was assumed that the full CCA load (1,035 GWH) was in each portfolio. In other words, if, for example, the CCA decides to offer both 100% Renewable and SDG&E Equivalent Renewable products and some proportion of customers fall into each product bucket, the emissions would fall somewhere between 0 and 212,000 metric tons of CO_2e/year.

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[33] http://www.energy.ca.gov/pcl/labels/2017_index.html

Exhibit 26 Comparison of Average Annual GHG Emissions from Electricity by Resource Portfolio (2021-2030)					
	1: SDG&E Equivalent Renewable Portfolio	2: 50% to 100% Renewable by 2035	3: 75% to 100% Renewable by 2030	4: 100% Renewable	SDG&E
Avg./GHG Share	53%	68%	88%	100%	53%
Avg. Emissions (Metric Tons CO2)	173,106	117,845	45,274	0	173,106
Difference SDG&E Portfolio (Metric Tons CO2)	0	55,261	127,832	173,106	0
Savings expressed as Number of Cars Off the Road[1]	0	12,000	28,000	37,000	0

[1] Passenger cars, based on 4.6 metric tons of CO2 per year assuming 22 mpg and 11,500 miles per year.

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 Partner cities. Increased renewable energy use can be accomplished by supporting customers wishing to own small renewable generation (net energy metering), purchasing from small local for-profit renewable generators (feed-in tariffs), purchasing renewable resources directly, or supporting electric vehicle use. The Chula Vista and La Mesa CAPs identify other program goals in the areas of: building energy efficiency, energy efficient construction, clean energy transportation enhancement, electrification of buildings. CCA is a viable mechanism for developing and implementing these types of programs using funding from a variety of sources including CCA operating revenues, CPUC, and the California Energy Commission.

Each of these programs also yields economic development benefits by stimulating spending locally and saving local customers money. 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.

Economic Development Rate Incentive

There are several programs that CCAs can offer to stimulate indirect 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 to provide 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 the business to target the business sectors of interest to their service area. If, for example, 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, thus an incentive could be paid to the new industrial customer.

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. NEM programs allow energy customers who generate some or all of their own power to sell excess generation to the grid and benefit from a credit for those sales when they become a NEM consumer.

SDG&E currently offers a NEM program in which customers receive an annual "true-up" statement at the end of every 12-month billing cycle. This allows customers to balance credit earned in summer months (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.[34] All of these CCA-managed NEM programs offer greater incentives for customers in their service area to invest in more and larger Distributed Energy Resources (DER). 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. The Partner cities 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.

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 Partners' CCA could incentivize customers in their service area to develop local renewable resources.

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

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.[35] This model of CCA-owned resources provides CCAs with a guaranteed renewable power source as well as local economic stimulus.

Electric Vehicle (EV) Programs and Charging Stations

Encouraging electric vehicle use can both increase LSE total load and simultaneously 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 which combines the loads 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.[36] 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 the IOU.[37]

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.[38] Sonoma Clean Power (SCP) also provided qualified customers with incentives to purchase EVs in 2016 and continued the program in 2017.[39] The Partners' CCA could invest in similar projects to promote electric vehicle use within its service area.

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)[40] program. The CARE program is mandatory for IOUs per California Public Utilities Code 739.1. The program is set up for electric corporations that have 100,000 or more customer accounts to provide 30-35% discount on electric utility bills on households that are at or below 200% of the federal poverty

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

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

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

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

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

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

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 customers through SDG&E regardless of power supply provider (CCA or SDG&E).

In addition, the Family Electric Rate Assistance (FERA) Program can provide a monthly discount on electric bills. This program is designed for income-qualified households of three or more persons. Finally, the California Department of Community Services and Development (CSD) oversees a federal program, Low-income Home Energy Assistance Program (LIHEAP), which offers help for heating or cooling homes and help for weatherproofing homes.

At present, most California CCAs simply match their incumbent IOU's low-income programs, as in the case of MCE and SCP. The Partners' CCA would provide the same support to low-income customers as does SDG&E.

Economic Impacts in the Community

The analyses contained in this Study of forming a three-city CCA has focused only on the direct economic effects of this formation. However, in addition to direct effects, indirect microeconomic effects are also expected.

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

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

Environmental and Health Impacts – With the creation of a CCA, other non-commerce indirect effects 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 the economic development models used in this Study, the reduction of these GHG emissions are captured in indirect effects projected by the models to the extent that carbon prices are accounted for in the input-output matrix.[41]

Input-Output Modeling (IO Modeling) – County-wide electric rate savings and growth in manufacturing jobs and other energy intensive industries are expected to spur economic development impacts. Exhibit 27 below shows the effect $7.1 million in rate savings could have on the County economy as estimated in the San Diego County IMPLAN model.[42] The $7.2 million rate savings represents the minimum annual bill savings projected to occur once the CCA has achieved full operation if all of the Partner cities are included (SDG&E-Equivalent Renewable portfolio or 100% 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.

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

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[41] 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)

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

estimate the impact on the economy from reduced bills. Estimated household income distribution is based on the income percentiles from the statistical atlas for San Diego County.[43] 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 are likely underestimated.

Major agricultural activities in the County include nursery products, avocados, lemons, limes, tomatoes, and herbs. Major commercial and industrial industries include government, healthcare, retail, manufacturing, construction, professional and scientific services, finance, accommodation and food services, and wholesale trade.

Exhibit 27 details the net macroeconomic impacts anticipated from the 2% savings in the rate after forming the CCA. The total output for one year of rate savings is estimated at $10.3 million. Finally, the rate savings are estimated to produce an additional 86 full time jobs.

Exhibit 27
$7.1 Million Rate Savings Effects on the San Diego County Economy[1]

Impact Type	Employment	Labor Income	Total Value Added	Output
Direct Effect	40	$1,951,000	$1,979,000	$3,639,000
Indirect Effect	8	$506,000	$820,000	$1,373,000
Induced Effect	37	$1,793,000	$3,271,000	$5,295,000
Total Effect	86	$4,250,000	$6,069,000	$10,307,000

1. Full impacts to San Diego county are estimated, it can be expected that a large share of these impacts would be realized within the 3 jurisdictions.

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. This in turn would give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand. In addition, reduced inputs to production for non-residential electric customers would allow companies to invest in other areas to promote growth such as hiring new employees, offering additional training, and purchasing upgraded equipment.

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

Sensitivity and Risk Analysis

The economic analysis provides a base case scenario for forming a Partner CCA JPA. This 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.

The following analysis is an overview of risks and their relative severity, followed by 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 56 percent of the total costs, SDG&E non-by-passable (PCIA/CTC) charges account for 35 percent, and operating costs account for 8% of total CCA revenue requirement. The figure below (Exhibit 28) illustrates this breakdown of CCA costs. Exhibit 29 provide discussion of each risk factor.

Exhibit 28
Rate Comparison Scenario 2: 50% Renewable at Launch and 100% Renewable by 2035

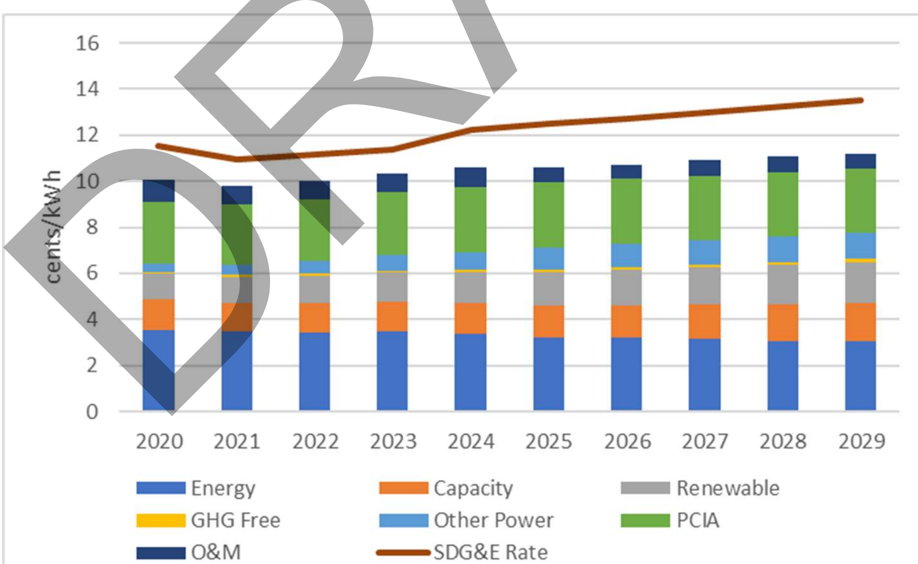


Exhibit 29
Comparison of Risks, Mitigation Strategies, and Risk Severity

	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 – May become more difficult to offer savings in the short-term if PCIA changes significantly.
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 -the CCA and SDG&E face the same market conditions
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	Low – CCA would have capability to increase renewable energy purchases to match or exceed SDG&E if the	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
					result of other CCA departures.	event occurs. In addition, CCA would promote other benefits of its service to customers.	
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 – to date, there has not been an instance of a CCA not obtaining the needed financing for launch.
7	Loads and customer participation	Unprecedented opt-out rate reduces competitiveness	• Excess power contracts • Poor margins	• Increase marketing • Reduce overhead • Expand to new customer markets • Consider merging with existing CCA	Low – as CCAs have become more common in California, and CCA marketing firms more experienced, opt-out rates have gone lower.	Low –CCA would have numerous viable options in the event they suffer unexpectedly low participation.	Low – The size of the Partners CCA is large enough that even low participation would not significantly

	Risk	Description	Problem	Mitigation Strategy	Likelihood of Problem	Severity of Problem	Potential to "Suspend" CCA
							impact the program.

SDG&E Rates and Surcharges

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

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 resource mix and renewable resource growth rates. 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 was modeled in the high and low case by incorporating higher and lower generation growth rates. This results in SDG&E's power supply average annual growth rate in the high case of +2% and in the low case of -2%.

PCIA

When legislation was introduced to allow the formation of CCAs, it was recognized that the IOUs currently serving the potential CCA customers may face stranded generation costs. The PCIA methodology was established by the CPUC as a means for IOUs to recover those stranded costs. The PCIA faces several issues, however, including the source and transparency of data used for the calculation and the fact that the PCIA level is 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 Partners' 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 of the 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. Therefore, over time the PCIA would vary, but it is expected that it would decline as market prices increase and grandfathered contracts expire.

Forecasting the PCIA is difficult since key inputs are heavily redacted from the rate filings and regulatory changes can significantly impact the PCIA. The uncertainty associated with forecast PCIA rates is modeled considering historic PCIA increases as well as the adopted methodology used for the PCIA calculation (October 11, 2018). In addition to the base case, a low and high PCIA forecast are modeled. The low scenario is 10% lower than the forecasted assumption. In the high scenario, the PCIA increases by the full cap of $0.005/kWh in the first 2 years then de-escalates at an average of 5% per year.

Franchise Fees

IOUs pay franchise fees to municipalities as compensation for the right to run pipes, wires, and product through municipal land. These costs are passed on to customers in the form of a rate-adder to both distribution and generation costs. These collections are pooled by the utility and then distributed among the counties and municipalities in which they operate.

Franchise fees are defined through a franchise agreement made between a municipality and a utility addressing both the distribution and generation components of the fee. Franchise fees are typically in the range of 1-2% of gross revenue. On June 18, 1993, California Senate Bill 278 added the Surcharge Act (sections 6350-6354) to the Public Utilities Code. This Act requires that municipalities continue to receive generation remittance from DA and CCA customers. Therefore, implementation of a CCA program will not reduce expected franchise fee revenue due to the Partners.

Regulatory Risks

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 or additions, and gas prices all can impact SDG&E's rates in the future. Regulatory issues continue to arise that may impact the competitiveness of the Partners' 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 can also impact the Partners' CCA. For example, new legislation that recently affected CCAs is SB 350. The CCA-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCAs must be aware, however, of this legislation's long-term contracting requirement associated with renewable energy procurement. Specifically, CCAs are required to contract 65% of renewable resources for 10 years or more by 2021. It may be difficult for a new CCA to obtain long-term contracts initially; however, RPS compliance periods are three years. The compliance period may help to provide new entities a chance to make the required procurements.

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.

Finally, SDG&E has asked lawmakers to introduce legislation (AB56, Garcia) that would eventually result in the IOU leaving the power supply business. SDG&E is faced with losing half of its customers as the City of San Diego is poised to launch its CCA program. SDG&E is asking that the legislature pass a bill that would create a way for the utility to sell long-term power contracts to a "state-level electrical procurement entity." This entity could then re-sell the contracts to other buyers. Any difference in price would then become a non-bypassable charge to former SDG&E bundled customers. The non-bypassable charge would likely be similar to the PCIA/CTC and the PCIA/CTC would no longer be in effect. This bill was recently amended to clarify that the state agency would procure only backstop power, or power that was specifically bought at the request of a load serving entity.

While the current proposed legislation has been amended to a backstop role, the Resource adequacy proceedings could result in regulatory changes for RA procurement. If this legislation or regulation becomes law/rule, a new exit fee mechanism could result in lower charges to CCA customers. A state-level procurement entity would be a public agency, and be subject to a lower cost of capital. These lower charges would benefit CCA customers. The downside of a central procurement agency would be the loss of local control in power supply choices. It is not clear how much loss of control would be realized since the central procurement agency might purchase power supply as a provider of last resort, or the agency might purchase all power supply requirements.

Power Supply Costs

Ramping services are predominantly provided by natural gas-fired generating resources. These resources are capable of ramping generation levels up and down quickly to assure that resources are equal to load requirements. Therefore, wholesale market prices are driven largely by natural gas prices. In addition, the CCA's power supply mix has been modeled according to different levels of renewable energy. Renewable energy costs are forecast for the base case; however, several factors could influence future renewable energy costs including locational factors for new facilities, transmission costs, technology advancements, changes in state and federal renewable energy incentives, or changes in California or neighboring state RPS.

Since resource costs are based on forecast wholesale market and renewable market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculations to fluctuations in projected prices. Exhibit 30 below shows a summary of low, mid-range, and high resource costs.

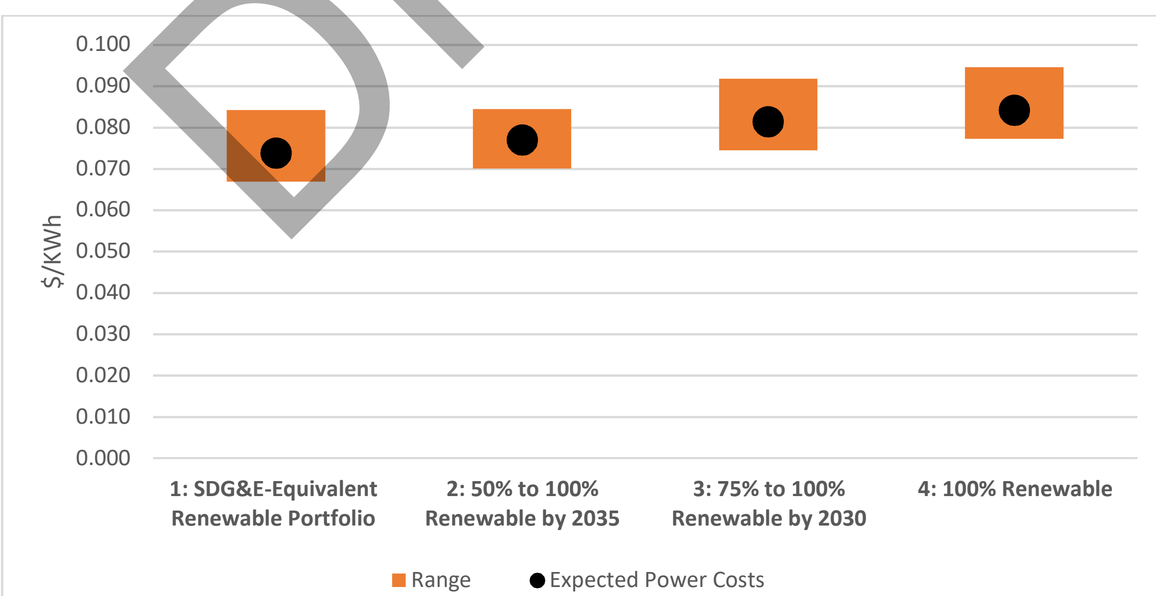
Exhibit 30
Power Supply Cost Sensitivity
$/kWh

Case	1: SDG&E-Equivalent Renewable Portfolio	2: 50% to 100% Renewable by 2035	3: 75% to 100% Renewable by 2030	4: 100% Renewable
Low Case	0.0669	0.0701	0.0745	0.0773
Base Case	0.0738	0.0770	0.0814	0.0842
High Case	0.0842	0.0845	0.0918	0.0946

As discussed in the "Power Supply Strategy and Costs" section of this Study, the Mid-range renewable energy costs are conservative in that they are greater than the cost of long-term renewable PPAs currently being executed in the region. The Low Case renewable energy costs are based on an assumption that the costs of renewable generating projects will, as expected, continue to decline and the CCA would, over time, layer in PPAs sourced to the lower cost renewable resources that will be developed over the next five to ten years. The High Case renewable energy costs are based on an assumption that the CCA is not able to secure PPAs sourced to relatively new and lower cost renewable resources but, rather, signs PPAs sourced to older renewable resources with higher costs. The renewable costs in this case reflect the costs of renewable resources that were developed three to five years or more ago.

The 20-year levelized costs of each portfolio has been calculated using the range of resource costs shown above. The base case costs are depicted by the black dots in Exhibit 31, while the range projected between the High Case and the Low Case are depicted by the orange bar.

Exhibit 31
Sensitivity of Portfolio 20-year Levelized Costs $/kWh



The 100% Renewable portfolio (Scenario 4), which relies on the most renewable energy purchases to serve retail load, has the highest projected costs that range from a low of $0.077/kWh to a high of $0.095/kWh. There is a low likelihood that renewable project costs would increase to the point that 20-year levelized costs of renewable purchases is near $0.0100/kWh. It is far more likely that decreases in solar equipment costs on a $/watt basis will continue.

While renewable energy costs continue to decline, the potential for market PPA prices to increase could be material. Wholesale market prices are dependent on many factors, the most notable of which is natural gas price. Natural gas prices are at historic lows, and because natural gas-fired resources are often the marginal resource in the market, wholesale market prices have followed. Natural gas prices are subject to a variety of local, national and international forces that could have a large impact on the current marketplace. For example, increased regulation in the natural gas industry with respect to the deployment of fracking technology could cause decreases in natural gas supplies and commensurate increases in natural gas prices. Additionally, increased costs associated with carbon taxes and/or carbon cap and trade programs could also cause upward pressure on wholesale market prices.

Finally, congestion at Southern California Citygate due to Aliso Canyon curtailments, and delayed pipeline work, have resulted in day ahead price spikes since October 2017. The impacts of Aliso Canyon are not limited to Southern California as the marginal resources in the South impact the marginal resources in the North. This new normal in natural gas price level and volatility will impact the wholesale market for electricity in the same manner. These impacts are accounted for in the market price forecast and tested in the sensitivity analysis.

SDG&E RPS Portfolio

There are several factors that may impact the share of renewable energy in SDG&E's portfolio over the next decade. Customers departing SDG&E for CCA service throughout SDG&E territory would have the effect of shrinking SDG&E's load, thereby increasing the share of renewables made up by SDG&E's current RPS contracts. Finally, SDG&E could further strive to compete with CCAs in terms of the environmental impact of its power portfolio. In combination, these forces could drive up the share of renewable energy in SDG&E's power mix to match or exceed the CCA's planned power mix. To mitigate this risk, the CCA would have the option to acquire more renewable energy in response to changes in SDG&E's portfolio.

Availability of Renewable and GHG-Free Resources

Often one of the goals of a CCA is to offer power products that are cleaner than those provided by the IOU. All of the portfolios developed for this Study are modeled at 60% to 100% GHG-free. As such, they include more renewable resources and exceed the share of GHG-free resources in SDG&E's power supply portfolio, which is in the 40% to 50% range.

SDG&E does offer additional renewable choice to customers. EcoChoice allows the customer to sign up for "50% to 100% renewable power" as shown in Exhibit 32.[44] This program is currently closed to commercial customers. EcoChoice has a minimum 1-year enrollment term and charges an exit fee if the customer decides to cancel participation. EcoChoice currently results in a discount off SDG&E's standard rate, because new renewable resources are cheaper than the existing resources committed to by SDG&E. However, the EcoChoice customer will have to pay the PCIA as would CCA customers.

Exhibit 32
EcoChoice Rates (Updated 01/01/2019)

Rate Component	Residential ($/kWh)	Small Commercial ($/kWh)	M/L Commercial and Industrial ($/kWh)	Agriculture ($/kWh)	Street Lighting ($/kWh)
Renewable Power Rate & Program Costs & Transmission	0.07195	0.07195	0.07195	0.07195	0.07195
SDG&E's Average Commodity Cost Adjustment	-0.1087	-0.10725	-0.11047	-0.09108	-0.07913
EcoChoice Differential	**-0.03675**	**-0.0353**	**-0.03852**	**-0.01913**	**-0.00718**
2019 PCIA	0.03305	0.02979	0.02082	0.02511	0.02189
Total Cost	**-0.0037**	**-0.00551**	**-0.0177**	**0.00598**	**0.01471**

For residential customers, the discount per kWh for participating in EcoChoice is $0.03675 per kWh. However, after applying the PCIA, this discount is reduced to $0.0037 per kWh. The results for SDG&E's EcoChoice program over time are anticipated to be similar to the estimated cost for the 100% renewable product from the CCA because any PCIA changes will impact both the CCA and the EcoChoice programs. While the current estimate for the 100% renewable by 2035 program indicates that the cost will be 2% below SDG&E standard generation rate for all customers, the 100% renewable program is at a small discount to the SDG&E rate. Changes in the PCIA will impact the EcoChoice program and likely result in EcoChoice rates that are above SDG&E rates for ***all*** rate classes.

SDG&E's EcoShare program allows the customer to contract directly with a renewable project developer and purchase the rights to a portion of the output from a new local renewable generating facility. Customers participating in EcoShare will receive a credit on their SDG&E bill reflecting the amount of renewable energy purchased through the developer. In addition, the customer pays the PCIA and other program costs, such as the administrative costs.

The primary risk associated with a high renewable resource strategy is lack of sufficient renewable resources at prices that would keep the CCA competitive with SDG&E. The current market has sufficient renewable resources available. Utilities that submit requests for renewable

[44] https://www.sdge.com/sites/default/files/2019%20EcoChoice%20Price%2C%20Terms%2C%20and%20Conditions%20Summary.pdf

power supply receive bids that far exceed the requested amounts at prices that are very competitive to non-renewable market resources. As RPS requirements and the share of renewable resources in CCA portfolios are increasing, competition for renewable resources could increase. However, it is important to note that the CCA movement does not change the total load. Rather, the renewable resource timeline may just have accelerated until targets have been reached. Increased competition would result in increased prices once supply cannot meet the demand, resulting in increased development of renewable resources. In addition, the CCAs would have the opportunity to aid in the development of renewable resources by fostering local resource development.

Financial Risks

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

The Partner cities 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, thus minimizing the fixed costs of operating the CCA.

The Partners' 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 the Partners' CCA.

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 85% 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 the CCA Partners. 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 low case assumes a -0.14% growth in energy and customers after 2019, while the high scenario assumes a 1.32% growth in energy and customers.

The experience of existing CCAs suggest that only a small number of customers opt-out. For example, Peninsula Clean Energy has an opt-out rate of 2%, while Clean Power Alliance has a current opt-out rate of 0.7%. Once a CCA is operating, the number of customers switching back to the incumbent IOU have 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.

Sensitivity Results

Exhibit 33 provides the results of the sensitivity analysis for Scenario 2: 50% Renewable at Launch and 100% renewable by 2035, which is the most likely portfolio for the CCA to pursue initially given its goals.

Exhibit 33
Scenario 2 Portfolio – Bundled Rates ($/kWh)
10-Year Levelized Average System Rate

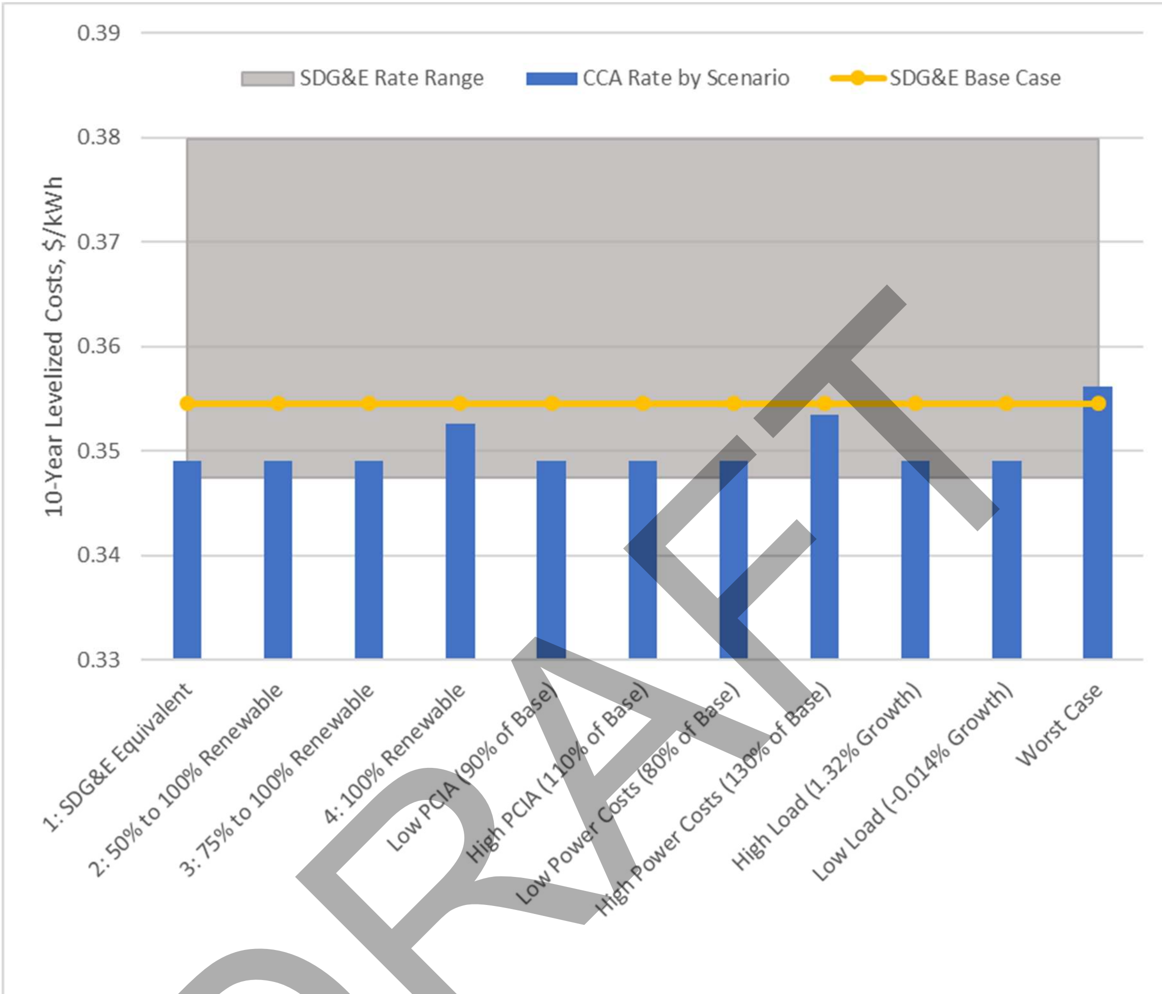


Exhibit 33 provides a comparison of the average system rate under several scenarios. This sensitivity shows that it is a significant risk to the CCA if the CCAs power costs increase based on the high-power cost scenario without any offsetting PCIA benefits. The CCA's rates could also be higher than SDG&E's under a "Worst Case" scenario. This scenario could arise when the CCA does not achieve sufficient customer participation, CCA power supply costs are high, and SDG&E charges a high PCIA.

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

While the CCA 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 allocated 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 (15% 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 the Partners' 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 consider implementing a rate stabilization fund so that short-term events that result in lower SDG&E rates compared with the CCA rates can be mitigated with reserves rather than by rate increases. Reserves would help the CCA remain competitive and would provide rate stabilization for customers.

CCA Governance Options

The Study evaluates a Partners CCA JPA throughout the document and Appendix F provides the results of the individual city analyses where each city forms an enterprise fund and operates a CCA individually. This section of the Study further discusses governance options that may be available to the Partners either individually or together. These include:

1. Enterprise – Each city operating its own CCA
2. Partner CCA – A 3-city CCA program with Chula Vista, Santee, and La Mesa
3. Hybrid CCA – The Partners establish a JPA to share administration costs but each city obtains its own power supply
4. Regional CCA– Join the City of San Diego-led efforts to form a Regional CCA
5. Partnering with an existing CCA program (Solana Energy Alliance)

Rate impacts, timing of launch, staffing organization, and local control aspects of these options are also explored.

Enterprise

An enterprise CCA is a CCA program that is run by a City department much like cities that operate water or wastewater utilities.

- *Financial Viability*: This is likely viable for each city. EES has analyzed this option and has financial pro-forma results in Appendix F
- *Governance*: An enterprise model usually results in less complicated governance.
- *Local Control*: Decision-making is more locally focused.
- *Other Attributes*: Solana Beach, Pico Rivera, San Jacinto, and King City are examples of smaller city CCAs that are operating independently; although Pico Rivera and San Jacinto participate in the California Choice Energy Authority to share non-power costs with other individual city CCAs. Individual city CCAs are likely feasible but net revenue margins will be smaller without sharing non-power supply costs with others. Operating a city CCA requires special care to protect the city's general fund from CCA obligations. Individual city CCAs may apply to the CPUC for energy efficiency funding but the amount will be less than a CCA JPA with a larger retail load.
- *Risks/Considerations*: An enterprise fund offers the most local control in the program organization. There may be some increased risk or special considerations in power supply contracts that will need to be evaluated to protect the city general fund. An enterprise fund generally retains all risk if funds are not commingled with the general fund or other special purpose funds. The enterprise, though does contract in the name of the city, and is not its own legal entity as is a JPA. Should liabilities exceed revenues, or should the CCA default on an obligation, counter-parties would likely seek redress from the city itself. Also, the enterprise is subject to Prop 26 rate setting and all enterprise fund expenditure and

accounting rules that would otherwise be borne by a JPA. Another drawback is that an enterprise may not avoid the constitutional limit on indebtedness.[45]

Exhibit 34 details the estimated start-up costs for enterprise funds.

Exhibit 34 Costs to Establish Enterprise CCA	
Pre-Launch Costs	$600,000-800,000 (each)
Start-Up and Working Capital (Financed)	Chula Vista: $5 million La Mesa: $4 million Santee: $3 million
Estimated Bundled Rate Discount	Chula Vista: 2% La Mesa: 1% Santee: 1%
Probable Launch Date	2022
Power Supply Cost Allocation	Power supply obtained individually

Partner CCA

The Partner CCA entails the Partner Cities developing a JPA among the three of them. In this option, the Partners would be able to draft language in the JPA that meets the specific needs of the cities involved. A Partner CCA would have more control over what new members are added, if any, and local control would remain with the three cities. The JPA board would most likely consist of on elected official from each city.

- *Financial Viability*: This Study shows that a 3-member JPA is financially viable.
- *Governance*: Under a JPA, likely each city would be a voting board member. Having a limited number of board members keeps governance nimble and local/regional control focused.
- *Local Control*: Since the Partners have similar climate action goals, and collaborated on this Study for similar purposes, decisions around the CCA's operations should be less complicated. Decisions about wholesale power portfolio, rate designs, local distributed generation, and customer clean energy programs should be easier to make.
- *Other Attributes*: A JPA of this size is ideal for allowing other San Diego County cities that create their own CCAs to join. Consideration of consistent goals, local programs and operations design should be considered for new CCA cities. Operational savings on non-power supply costs (administration, legal, regulatory, and other services) would likely occur. A JPA provides clear financial protection of cities' general funds from CCA obligations. A JPA could apply to the CPUC for energy efficiency program funds on behalf of the cities.
- *Risks/Considerations*: The JPA structure is prevalent governance model for CCAs. CCA JPAs have grown in membership as new jurisdictions choose to pursue CCA. The trade-off in JPA size and local control should be carefully considered. Established JPA agreements provide the best practices for protecting city general funds.

[45] Statements provided by Santee's city attorney.

Exhibit 35 details estimated start-up costs for a Partners JPA.

Exhibit 35 Costs to Establish Partner CCA	
Pre-Launch Costs	$600,000-800,000
Start-Up and Working Capital (Financed)	SDG&E Equivalent RPS: $8 million 100% Renewable by 2030: $10 million
Estimated Bundled Rate Discount	2%
Probable Launch Date	2022
Power Supply Cost Allocation	Power supply obtained at the same time

Enterprise JPA

An Enterprise JPA is a JPA where only some of the program costs are shared. For CCAs this is typically the program administration costs. Under this option each City would form its own CCA and the CCA's would join together in a JPA for program management. Each city is responsible for obtaining power supply and setting rates, and each city retains any excess funds for new programs or local project development.

- *Financial Viability*: This Study shows that a 3-member JPA is financially viable.
- *Governance*: Under a JPA, likely each city would be a voting board member. Having a limited number of board members keeps governance nimble and local/regional control focused.
- *Local Control*: Since the Partners have similar climate action goals, and collaborated on this Study for similar purposes, decisions around the CCA's operations should be less complicated. Decisions about wholesale power portfolio, rate designs, local distributed generation, and customer clean energy programs would be maintained by each city.
- *Other Attributes*: An Enterprise JPA is attractive to many jurisdictions because each city maintains local control over power supply and rates meanwhile sharing overhead costs and benefiting from economies of scale. This option is particularly attractive when several jurisdictions have even slightly different power supply goals, but want to benefit from not duplicating administrative efforts.
- *Risks/Considerations*: An Enterprise JPA option allows jurisdictions with different goals to benefit from economies of scale. However, because the cities would each have their own CCA, this governance option raises some of the same concerns as the enterprise option regarding contracting and rates.

Exhibit 36 details estimated start-up costs for an Enterprise JPA.

Exhibit 36 Costs to Establish Enterprise JPA CCA	
Pre-Launch Costs	$600,000-800,000
Start-Up and Working Capital (Financed)	SDG&E Equivalent RPS: $8 million 100% Renewable by 2030: $10 million
Estimated Bundled Rate Discount	2%
Probable Launch Date	2022
Power Supply Cost Allocation	Power supply obtained at the same time

Regional CCA JPA

The City of San Diego is planning to form a JPA and is inviting other jurisdictions to join in the process.

- *Financial Viability*: A large JPA, with the potential of up to 18 members, is financially viable and there will be some marginal economies of scale when compared with a Partner JPA.
- *Governance*: Decision making is often delegated to committees. Risk sharing is greatly reduced as the size of the JPA jumps considerably and the upfront start up cash can be carried by the larger Cities. In limited situations, the Partners' votes may be impacted by weighted voting agreements.
- *Local Control*: CCAs that join the Regional CCA will need to negotiate for voting representation. Likely each member city will have one vote with additional voting based on relative size of JPA members for limited situations. Weighted voting can take many different forms including two-tier voting and special considerations for veto votes. Additional discussion with the City of San Diego would be needed to determine how the voting structure will be determined. The JPA is not finalized, so there is time for the Partners to influence member roles, benefit distribution, and other agreements. The City of San Diego is also in the process of re-negotiating its franchise agreement with SDG&E, which expires in 2020. It is not clear what effect that process will have on the City's proposed JPA, if any
- *Other Attributes*: There would be low or no start-up costs for joining the City of San Diego. Economies of scale rate savings are shown in Exhibit 37. Additional rate savings for joining a large CCA are estimated at between 0.8% off SDG&E bundled rates.
- *Risks/Considerations*: As mentioned above, the potential size of this specific JPA could dilute local control.

Exhibit 37 Economies of Scale for Staffing and Consultants			
	San Diego	Partners	San Diego + Partners
Staffing, FTE	20	10	20
Administration Costs	$7,000,000	$3,165,000	$7,000,000
Retail Load, MWh	6,388,879	1,057,261	7,446,140
Admin Costs, $/kWh	$0.00110	$0.00299	$0.00094
Power Supply and Other Costs, $/kWh	$0.06440	$0.06440	$0.06440
Total Rate, $/kWh	$0.06550	$0.06739	$0.06534
Economies of Scale Savings			-3.0%
Bundled Rate, $/kWh	$0.258	$0.260	$0.258
Bill Savings			-0.8%

Exhibit 38 shows the estimated start-up costs for joining the City of San Diego in a Regional CCA.

Exhibit 38 Costs to Join Regional CCA	
Pre-Launch Costs	$0
Start-Up and Working Capital (Financed)	$0
Power Supply Cost Allocation	Partners share equally in power supply costs
Estimated Bundled Rate Discount	At least 2%
Launch Date	2021

CCA JPA with Solana Energy Alliance or other Existing JPA

The Cities could conceivably join the already operating Solana Beach CCA (SEA). SEA has been actively pursuing partnerships with other jurisdictions. SEA is a fraction of the size of the Partners in terms of load, and this may create complications in negotiating the roles of each of the cities, sharing of revenues and costs, and other decision-making issues.

- *Financial Viability*: This option would be financially viable and would allow SEA to enjoy economies of scale savings for their program.
- *Governance*: Likely each member would have one vote, as this is the most common arrangement in existing CCA JPA models.
- *Local Control*: As the largest members of the resulting JPA, the Partners would retain significant decision-making power. SEA is currently organized to operate with an executive director plus consultants to manage most of the operation. It is not clear if SEA contracts with these consultants is a limiting factor for Partner choice in hiring consultants or dedicated CCA staff. Adjustments to existing SEA contracts and power management would need to be made to incorporate new members.
- *Other Attributes*: Net revenue margins for the organization as a whole benefit from adding SEA. How these revenues are utilized to benefit members must be determined by the member cities, likely with differing local goals regarding CCA operations. A larger JPA of CCAs could apply for larger amounts energy efficiency funds but the design of the programs becomes more complicated.

- *Risks/Considerations*: SEA has been operating since 2018 and has experience in implementing and running a CCA program. The Partners could benefit from this experience, and joining SEA might be an option for a city who would like to join a JPA but does not wish to join the City or with other local entities.

Exhibit 39 estimates the timing but not the costs for establishing a JPA with SEA.

Exhibit 39
Costs to Establish JPA with SEA

Pre-Launch Costs	Not Determined
Start-Up and Working Capital (Financed)	Some fee may be required
Estimated Bundled Rate Discount	Undetermined
Probable Launch Date	2022
Power Supply Cost Allocation	Power supply obtained incrementally

Recommendation

Exhibit 40 summarizes the governance key cost information.

Exhibit 40
Estimated Costs to Establish CCA by Governance

	Enterprise	Partners CCA	Regional CCA	JPA with SEA	Enterprise JPA
Pre-Launch Costs	$600,000-800,000 (each)	$600,000-800,000	$0	Not Determined	$600,000-800,000
Start-Up and Working Capital (Financed)	Chula Vista: $5 million La Mesa: $4 million Santee: $3 million	$8-$10 million	$0	Some fee may be required	Chula Vista: $5 million La Mesa: $4 million Santee: $3 million
Estimated Bundled Rate Discount	Chula Vista: 2% La Mesa: 1% Santee: 1%	2%	At least 2%	Undetermined	2%
Probable Launch Date	2022	2022	2021	2022	2022
Power Supply Cost Allocation	Power supply obtained individually	Power supply obtained at the same time	Shared power costs	Power supply obtained incrementally	Power supply obtained individually

As the Partners move towards CCA adoption by their governing organizations, or after the cities approve creating a CCA, they should further investigate each of these options. EES recommends that the cities further discuss the options among themselves to more clearly understand all of the pros and cons. The cities should develop a more detailed assessment of the options of joining existing organizations or developing new, local/regional organizations. The assessment would consider political and cultural similarities, potential for rate reductions, implementation costs, local control, and individual city goals.

This Study evaluates the feasibility of operating a CCA under the JPA model with the three Partner cities (Partner CCA). The financial sensitivity analysis provided in Appendix F also provides feasibility results for each Partner city operating their own CCA. If the Partners join an existing JPA, the start-up activities are simpler as the organization is already operating and programs have been developed. However, the overall governance issues would have to be established prior to the cities joining the existing CCA.

CCA Organizational Options

If the 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 a Customer Service Manager, to oversee consultants that would perform all necessary 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 Partners would operate a CCA with limited staff supported by consultants experienced in power procurement, data management and utility operations. If the Partners decide to transition some administrative and operational responsibilities to internally staffed positions, the CCA could reach a full-time staff of approximately 10 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 billings would likely still be performed by an experienced third-party consultant.

Conclusions and Recommendations

Rate Conclusions

The first impact associated with forming the Partners' CCA would be lower electricity bills for CCA customers. CCA customers should see no obvious changes in electric service other than the lower price and potentially more renewable power procurement, depending on the CCA's goals. Customers 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's rate setting can establish a goal of providing rates that are equal to or lower than the equivalent rates offered by SDG&E even under Scenarios 2 and 3. The projected CCA and SDG&E rates are illustrated in Exhibit 41.

Exhibit 41
Rate Comparisons, Total Bill $/kWh

Rate Class	2021 SDG&E *	1: SDG&E Equivalent Renewable	2: 50% to 100% Renewable by 2035	3: 75% to 100% Renewable by 2030	4: 100% Renewable
Residential	0.3576	0.3504	0.3504	0.3504	0.3540
Commercial & Industrial	0.2491	0.2442	0.2442	0.2442	0.2467
Lighting	0.1804	0.1768	0.1768	0.1768	0.1786
Agricultural	0.1240	0.1215	0.1215	0.1215	0.1228
Total	**0.3077**	**0.3016**	**0.3016**	**0.3016**	**0.3046**
Bill Savings		**2.00%**	**2.00%**	**2.00%**	**1.00%**

*SDG&E bundled average rate projected based on SDG&E's 2019 Rates. Includes current time-of-use rate structure.

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.[46] This is an advantage to the CCA customers as they would then have local control of power supply costs through the CCA.

Renewable Energy Conclusions

A second outcome of forming a CCA would be an increase in the proportion of energy generated and supplied by renewable resources. The Study includes procurement of renewable energy sufficient to meet 50% or more of the CCA's electricity needs (initially). The majority of this renewable energy would be met by new renewable resources over time. By 2030, SDG&E must procure a minimum of 60% of its customers' annual electricity usage from renewable resources due to the State Renewable Portfolio Standard and the Energy Action Plan requirements of the

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

CPUC. The CCA can decide whether to follow the same renewable goals or to implement more aggressive targets.

Energy Efficiency Conclusions

A third outcome of forming a CCA would be a potential 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. The CCA customers would continue to pay the public goods charges to SDG&E which funds energy efficiency programs for all customers, regardless of supplier. The potential 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 for increased energy investment and savings with an attendant further reduction in emissions due to expanded energy efficiency programs.

Economic Development Conclusions

The fourth outcome of forming a CCA would be enhanced local economic development. The analyses contained in this Study has focused primarily on the direct effects of this formation. However, in addition to direct effects, indirect economic effects are also anticipated. The indirect effects of creating a CCA include the effects of increased local investments, increased disposable income due to bill savings, and improved environmental and health conditions.

Exhibit 42 shows the effects $7.1 million in electric bill savings could have in San Diego County. The $7.1million rate savings represents the estimated (maximum) bill savings per year achievable by the CCA once in full operation. It is estimated that the electric bill savings could create approximately 87 additional jobs in the County with over $4.2 million in labor income. It is also projected that the total value added could be approximately $6.1 million and output at $10.3 million.

Exhibit 42
$7.1 Million Rate Savings Effects on the San Diego County Economy[1]

Impact Type	Employment Jobs	Labor Income	Total Value Added	Output
Direct Effect	40	$1,950,000	$1,980,000	$3,640,000
Indirect Effect	8	$510,000	$820,000	$1,370,000
Induced Effect	37	$1,790,000	$3,270,000	$5,300,000
Total Effect	86	$4,250,000	$6,070,000	$10,310,000

[1]Full impacts to San Diego County are estimated, it can be expected that a large share of these impacts would be realized within the 3 jurisdictions.

These savings are based on the economic assumption 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. This in turn would give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand.

Greenhouse Gas (GHG) Emissions Conclusions

A fifth outcome of forming a CCA may be reduced GHG emissions. The amount of renewable power in SDG&E's power supply portfolio is 43% and will rise to 60% by 2030. Based on power supply strategy described previously, the estimated GHG emission reductions are forecast to range from zero to 173,106 tons CO_2e per year by 2030 assuming a 60% RPS target is achieved. The baseline for comparison is the SDG&E's portfolio resource mix versus the potential CCA resource mixes. Exhibit 43 details these reductions.

Exhibit 43
Comparison of Average Annual GHG Emissions from Electricity by Resource Portfolio (2021-2030)

	1: SDG&E Equivalent Renewable Portfolio	2: 50% to 100% Renewable by 2035	3: 75% to 100% Renewable by 2030	4: 100% Renewable	SDG&E
Avg./GHG Share	53%	68%	88%	100%	53%
Avg. Emissions (Metric Tons CO2)	173,106	117,845	45,274	0	173,106
Difference SDG&E Portfolio (Metric Tons CO2)	0	55,261	127,832	173,106	0
Savings expressed as Number of Cars Off the Road[1]	0	12,000	28,000	37,000	0

[1] Passenger cars, based on 4.6 metric tons of CO2 per year assuming 22 mpg and 11,500 miles per year.

Findings and Conclusions

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

- The formation of a CCA is financially feasible and could yield considerable benefits for all participating residents and businesses.
- Financial benefits include electric bills that are 2% lower compared with projected SDG&E bundled rates and resulting bills.
- 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, those risks can be mitigated

- The CCA could be a means to achieve local control of energy supply, and for cities to meet their respective Climate Action Plan (CAP) goals.
- Local electric rate savings are expected to stimulate economic development.

The positive impacts on the Partner cities and their citizens of forming a CCA suggest that CCA implementation should be considered with the following next steps: consideration of Joint Powers Authority or other governance options, Business Plan development, and Implementation Plan development. No likely combination of sensitivities would change this recommendation based on the detailed analysis contained in the balance of this report.

Recommendations

Based on the Study results, and recent CCA experience, the following recommendations are made pursuant of CCA formation:

- The CCA should initially contract with a third party with the necessary experience (proven track record, longevity and financial capacity) to perform most of the CCA's portfolio power supply operation requirements. This would include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading.
- The Partners' 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 the majority of risks and be responsible for their management. The protocols that cover electricity procurement activities should be developed before operations begin.
- The CCA should be flexible in its approach to obtaining power supply resources necessary to meet load requirements.
- Additionally, it is recommended that the Partners 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.

Summary

This Study concludes that the formation of a CCA in the Partner cities is financially feasible and could yield considerable benefits for all participating residents and businesses. Partner CCA benefits could include 2% lower rates for electricity compared to SDG&E, although higher rate reductions are possible. The positive impacts on the Partner cities and their inhabitants of forming a CCA suggest that this effort should be considered.

Appendix A – Projected Schedule: Partner JPA

			2019							2020												2021				
	Task	Due Date	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Feasibility Report	Final Draft Report	6/28/2019																								
	Council Presentations																									
	Chula Vista	7/23/2019																								
	La Mesa	7/23/2019																								
	Santee	7/24/2019																								
	Public Meetings	8/31/2019																								
Ordinance	Approval of Ordinance and Resolution to Create CCA	8/31/2019																								
Organizational Setup	Form JPA	9/1/2019																								
	Hire Executive Director	1/1/2020																								
	Hire Staff	6/1/2020																								
CPUC Registration	Prepare Implementation Plan	1/1/2020																								
	File Implementation Plan with CPUC	1/1/2020																								
	CPUC completes review of IP	4/1/2020																								
	Register with CPUC and submit Bond	4/1/2020																								
	CPUC confirms registration	5/1/2020																								
Resource Adequacy	File Historic Load Data with CPUC/CEC	3/17/2020																								
	File Year-Ahead Load Forecast	4/20/2020																								
	Revised Year-Ahead RA Load Forecast	8/16/2020																								
	January Month-Ahead RA Load Forecast Due	10/15/2020																								
Power Procurement	RFP & Contract for Scheduling Coordinator/Portfolio Mng	7/1/2020																								
	Develop risk management and procurement plan	9/1/2020																								
	Power Purchase and Contracting	1/1/2021																								
Banking & Credit	RFP & Contract for Line of Credit	8/1/2020																								
	Finalize financial Plan and Rates	10/1/2020																								
	Transaction Testing with SDG&E	12/1/2020																								
Customer Noticing	RFP & Contract for Data Mgmt, Billing, Call Cntr, and Mrkt	8/1/2020																								
	Systems Testing with SDG&E	10/1/2020																								
	CCA Website Finalized	11/1/2020																								
	Call Center and CRM Operational	12/1/2020																								
	Pre-Enrollment Notice 1	1/1/2021																								
	Pre-Enrollment Notice 2	2/1/2021																								
	Customer Program Transitions Notice	3/1/2021																								
	Program Launch	4/1/2021																								
	Post-Enrollment Notice 1	4/8/2021																								
	Post-Enrollment Notice 2	5/10/2021																								

Appendix B – Pro Forma Analysis

Scenario 2: 50% Renewable at Launch 100% by 2035

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Revenues from Operations ($)											
Electric Sales Revenues	$53,443,758	$79,658,888	$81,328,895	$83,660,920	$91,882,645	$94,596,442	$97,995,498	$101,178,725	$104,449,490	$108,427,393	$112,194,654
Less Uncollected Accounts	$106,888	$159,318	$162,658	$167,322	$183,765	$189,193	$195,991	$202,357	$208,899	$216,855	$224,389
Total Revenues	$53,336,871	$79,499,570	$81,166,237	$83,493,599	$91,698,880	$94,407,249	$97,799,507	$100,976,368	$104,240,591	$108,210,538	$111,970,265
Cost of Operations ($)											
Cost of Energy	$45,149,887	$65,639,711	$67,701,323	$70,809,615	$72,765,270	$75,194,534	$77,391,738	$79,565,046	$81,761,500	$84,275,236	$87,195,028
Operating & Administrative											
Billing & Data Management	$1,556,196	$2,168,572	$2,225,657	$2,284,245	$2,344,376	$2,406,089	$2,469,427	$2,534,432	$2,601,148	$2,669,621	$2,739,896
SDG&E Fees	$627,307	$374,185	$384,035	$394,144	$404,520	$415,168	$426,097	$437,314	$448,826	$460,641	$472,766
Consulting Services	$1,170,300	$1,747,668	$1,517,319	$1,547,666	$1,578,619	$1,610,191	$1,642,395	$1,675,243	$1,708,748	$1,742,923	$1,777,781
Staffing	$1,612,863	$1,891,994	$1,929,834	$1,968,430	$2,007,799	$2,047,955	$2,088,914	$2,130,692	$2,173,306	$2,216,772	$2,261,108
General & Administrative expenses	$219,963	$160,430	$163,638	$166,911	$272,249	$173,654	$177,127	$180,670	$286,283	$187,969	$191,728
Debt Service	$2,075,836	$2,264,548	$2,264,548	$2,264,548	$2,264,548	$0	$0	$0	$0	$0	$0
Total O&A Costs	$7,262,464	$8,607,396	$8,485,031	$8,625,945	$8,872,111	$6,653,058	$6,803,961	$6,958,351	$7,218,312	$7,277,926	$7,443,280
Total Cost	$52,412,351	$74,247,107	$76,186,354	$79,435,559	$81,637,381	$81,847,592	$84,195,698	$86,523,398	$88,979,812	$91,553,162	$94,638,308
Net Income from Operations	$924,519	$5,252,463	$4,979,883	$4,058,039	$10,061,499	$12,559,657	$13,603,809	$14,452,970	$15,260,779	$16,657,376	$17,331,957
Cash from Operations and Financing											
Net Income	$924,519	$5,252,463	$4,979,883	$4,058,039	$10,061,499	$12,559,657	$13,603,809	$14,452,970	$15,260,779	$16,657,376	$17,331,957
Cash from Financing	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cash Available	$10,924,519	$5,252,463	$4,979,883	$4,058,039	$10,061,499	$12,559,657	$13,603,809	$14,452,970	$15,260,779	$16,657,376	$17,331,957
Net Income Allocation											
Working Capital Repayment (Remainder)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs/Additional Rate Savings	$0	$0	$0	$0	$4,162,439	$12,559,657	$13,603,809	$14,452,970	$15,260,779	$16,657,376	$17,331,957
Total Reserve Outlays	$0	$0	$0	$0	$4,162,439	$12,559,657	$13,603,809	$14,452,970	$15,260,779	$16,657,376	$17,331,957
Rate Stabilization Reserve Balance	**$10,924,519**	**$16,176,982**	**$21,156,864**	**$25,214,904**	**$31,113,964**	**$31,113,964**	**$31,113,964**	**$31,113,964**	**$31,113,964**	**$31,113,964**	**$31,113,964**
CCA Total Bill	$232,994,699	$315,514,644	$323,820,252	$332,344,496	$347,435,751	$356,581,650	$365,968,305	$375,602,055	$385,489,403	$395,637,026	$406,051,775
SDG&E Total Bill	$237,749,693	$321,953,719	$330,428,828	$339,127,037	$354,526,277	$363,858,826	$373,437,046	$383,267,403	$393,356,534	$403,711,251	$414,338,546
Difference	$4,754,994	$6,439,074	$6,608,577	$6,782,541	$7,090,526	$7,277,177	$7,468,741	$7,665,348	$7,867,131	$8,074,225	$8,286,771
Savings	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%

Appendix C – Staffing and Infrastructure Detail

Scenario 2: 50% Renewable at Launch 100% by 2035

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	20310
Infrastructure											
Computers	51,000	-	-	-	51,000	-	-	-	51,000	-	-
Furnishings	51,000	-	-	-	51,000	-	-	-	51,000	-	-
Office Space	55,080	74,909	76,407	77,935	79,494	81,084	82,705	84,359	86,047	87,768	89,523
Utilities and other Office supplies	-	-	-	-	-	-	-	-	-	-	-
Board travel	5,508	7,491	7,641	7,794	7,949	8,108	8,271	8,436	8,605	8,777	8,952
Memberships	57,375	78,030	79,591	81,182	82,806	84,462	86,151	87,874	89,632	91,425	93,253
Energy Coalition	-	-	-	-	-	-	-	-	-	-	-
Total Infrastructure Costs	219,963	160,430	163,638	166,911	272,249	173,654	177,127	180,670	286,283	187,969	191,728
Consulting											
Legal/Regulatory	76,500	104,040	106,121	108,243	110,408	112,616	114,869	117,166	119,509	121,899	124,337
Advertising/Communication	153,000	208,080	106,121	108,243	110,408	112,616	114,869	117,166	119,509	121,899	124,337
Human Resources firm	-	-	-	-	-	-	-	-	-	-	-
Technical Consultants	91,800	124,848	127,345	129,892	132,490	135,139	137,842	140,599	143,411	146,279	149,205
Data Management	1,556,196	2,168,572	2,225,657	2,284,245	2,344,376	2,406,089	2,469,427	2,534,432	2,601,148	2,669,621	2,739,896
Financial Consulting	191,250	260,100	265,302	270,608	276,020	281,541	287,171	292,915	298,773	304,749	310,844
Accounting Services	-	-	-	-	-	-	-	-	-	-	-
IT	76,500	104,040	106,121	108,243	110,408	112,616	114,869	117,166	119,509	121,899	124,337
Ongoing Customer Support	114,750	312,120	159,181	162,365	165,612	168,924	172,303	175,749	179,264	182,849	186,506
Total Consulting Costs (excl Data Mgmt)	703,800	1,113,228	870,191	887,594	905,346	923,453	941,922	960,761	979,976	999,575	1,019,567
Power Management											
Scheduling Coordinator	466,500	634,440	647,129	660,071	673,273	686,738	700,473	714,482	728,772	743,348	758,215
Staffing	1,612,863	1,891,994	1,929,834	1,968,430	2,007,799	2,047,955	2,088,914	2,130,692	2,173,306	2,216,772	2261107.8
IOU Fees											
SDG&E Billing Fees	268,520	374,185	384,035	394,144	404,520	415,168	426,097	437,314	448,826	460,641	472,766
Director of Marketing and Public Affairs	358,787	-	-	-	-	-	-	-	-	-	-
Total IOU Fees	627,307	374,185	384,035	394,144	404,520	415,168	426,097	437,314	448,826	460,641	472,766

Appendix D – CCA Cash Flow Analysis

Scenario 2: 50% Renewable at Launch 100% by 2035

	2021 Jan	2021 Feb	2021 Mar	2021 Apr	2021 May	2021 Jun	2021 Jul	2021 Aug	2021 Sep	2021 Oct	2021 Nov	2021 Dec
Cash Flow												
Revenues												
CCA Generation Revenues	$0	$0	$0	$0	$435,491	$3,930,498	$4,760,145	$7,354,368	$8,953,960	$10,549,508	$10,411,870	$8,383,031
Uncollected accounts	$0	$0	$0	$0	$871	$7,861	$9,520	$14,709	$17,908	$21,099	$20,824	$16,766
CCA Revenues based on Projected Rates	$0	$0	$0	$0	$434,620	$3,922,637	$4,750,625	$7,339,659	$8,936,052	$10,528,409	$10,391,047	$8,366,265
Expenses												
Power Supply												
Power Procurement	$0	$0	$0	$0	$3,250,785	$3,308,159	$3,967,601	$7,590,932	$9,525,752	$9,080,875	$5,141,123	$4,388,413
Total Power Supply	$0	$0	$0	$0	$3,250,785	$3,308,159	$3,967,601	$7,590,932	$9,525,752	$9,080,875	$5,141,123	$4,388,413
CCA Program Costs												
Data Management	$0	$0	$0	$173,608	$173,908	$174,208	$174,673	$174,148	$173,718	$173,156	$172,985	$172,652
Scheduling Coordinator	$0	$0	$0	$51,833	$51,833	$51,833	$51,833	$51,833	$51,833	$51,833	$51,833	$51,833
IOU Fees (including Billing & Notification)	$180,098	$0	$180,098	$29,956	$30,008	$30,059	$30,140	$30,049	$29,975	$29,878	$29,848	$29,791
Consultants	$0	$0	$0	$78,200	$78,200	$78,200	$78,200	$78,200	$78,200	$78,200	$78,200	$78,200
Staffing	$73,897	$73,897	$73,897	$154,575	$154,575	$154,575	$154,575	$154,575	$154,575	$154,575	$154,575	$154,575
General & Admin	$0	$0	$0	$115,107	$13,107	$13,107	$13,107	$13,107	$13,107	$13,107	$13,107	$13,107
Debt Payment	$0	$188,712	$188,712	$188,712	$188,712	$188,712	$188,712	$188,712	$188,712	$188,712	$188,712	$188,712
CPUC Bond	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E Bond	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses (excl PCIA)	$253,995	$262,609	$442,707	$791,991	$3,941,128	$3,998,854	$4,658,841	$8,281,556	$10,215,872	$9,770,337	$5,830,383	$5,077,282
Cash flow												
Beginning Balance	$0	$9,746,005	$9,483,396	$9,040,689	$8,248,697	$4,742,190	$4,665,972	$4,757,756	$3,815,860	$2,536,040	$3,294,112	$7,854,775
Additions												
Revenues	$0	$0	$0	$0	$434,620	$3,922,637	$4,750,625	$7,339,659	$8,936,052	$10,528,409	$10,391,047	$8,366,265
Financing	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reductions	$253,995	$262,609	$442,707	$791,991	$3,941,128	$3,998,854	$4,658,841	$8,281,556	$10,215,872	$9,770,337	$5,830,383	$5,077,282
Ending Balance	$9,746,005	$9,483,396	$9,040,689	$8,248,697	$4,742,190	$4,665,972	$4,757,756	$3,815,860	$2,536,040	$3,294,112	$7,854,775	$11,143,758

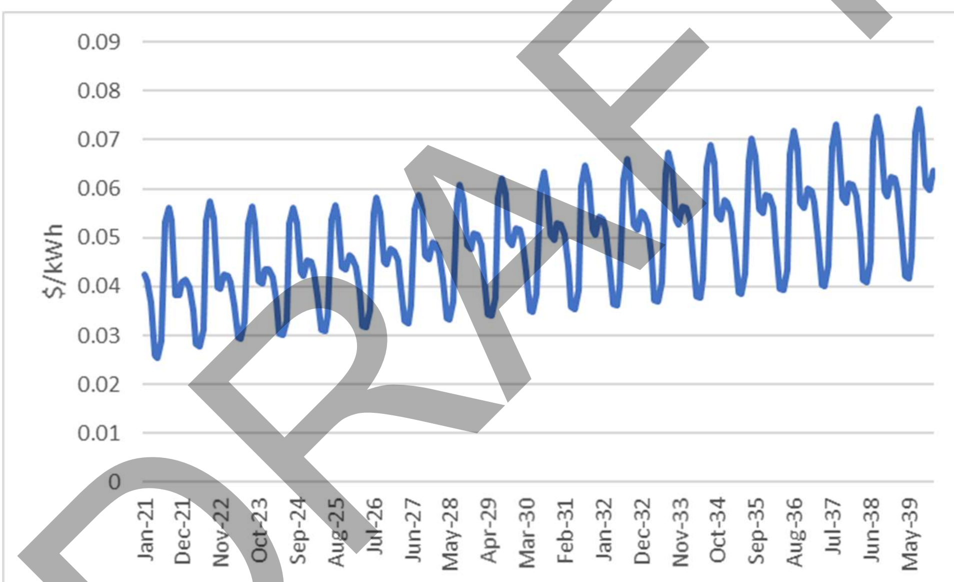
Appendix E – Power Supply Detail

Wholesale Market Prices

Market prices for SP15, which is the southern California energy market location, were taken from S&P Global. An adder of $1/MWh was included in the forecast PPA prices to account for potential price differences between SP15 and the pricing nodes at which the CCA would transact.

Exhibit E-1 below shows forecast monthly southern California wholesale electric market prices. The levelized value of market prices over the 20-year study period is $0.0407/kWh (2018$) assuming a 4% discount rate. Electric market prices peak in the winter and summer when there is large heating and cooling load.

Exhibit E-1
Forecast Southern California Wholesale Market Prices



Wholesale power prices have been used to calculate balancing market purchases and sales. When the CCA's loads are greater than its resource capabilities, the CCA's scheduling coordinator would schedule balancing purchases and the CCA would incur balancing market purchase costs. 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 pre-schedule basis.

Ancillary and Congestion Costs

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

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

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

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

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

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

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

Based on a survey of ancillary service costs currently paid by CAISO participants, the CCA's ancillary service costs are estimated to be near $0.003/kWh. The Study's base case assumes ancillary service costs are $0.003/kWh in 2020, escalating by 20% annually through 2026 and at 5% thereafter. Serving a greater percentage of load, 60% to 100% as is modeled in the Study, with renewables would likely result in increased grid congestion and higher ancillary service costs. These increased costs are evaluated in the sensitivity analysis.

Scheduling Coordinator Services

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

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

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

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

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

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

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

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

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

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

Appendix F – Separate City Results

Introduction

A jurisdiction participation case was developed to present the impacts of designing a CCA with only one of the three jurisdictions. The main section of the Study includes results for all three cities; however, a single jurisdiction can individually establish and operate a CCA. The benefit of a single city CCA is that the city can make all policy decisions on revenues, power mix, and programs. However, all risk and liability associated with the CCA fall solely on this single jurisdiction. In this structure, it is recommended that the Partners develop contractual language to minimize risk to general funds, maintain adequate operating reserves, proactively track regulatory activities, and manage its energy portfolio. Solana Energy Alliance, Apple Valley Choice Energy, Lancaster Choice Energy, and CleanPowerSF are examples of single jurisdiction governance models.

The feasibility analysis found that the larger city of Chula Vista can establish a single jurisdiction CCAs and still provide 2% rate discounts to ratepayers. The cities of La Mesa and Santee only have about half of the load of Chula Vista. To operate a financially stable CCA in La Mesa and Santee, costs would have to be reduced further to ensure sufficient reserves are collected.

Analysis

The financial proforma model was developed for each city based on the Scenario 2 power supply portfolio. Power supply, data management, billing, SDG&E charges, and non-bypassable charges were reduced to reflect the lower load and number of customers. For the remaining costs, the assumptions were modified to meet the expected requirement for each city based on the potential number of customers.

Chula Vista

The City of Chula Vista has about 89,000 accounts or about 64% of the three-city total. If the City of Chula Vista decides to establish a standalone CCA, it was assumed that the staffing, consulting, and administrative costs would be approximately the same as a three-city CCA. The only change in costs assumed were related to power supply, data management and SDG&E charges. In addition, the working capital needs were reduced to $5 million. Based on this analysis, Chula Vista can offer 2% discount to SDG&E bills and collect up to $14 million in reserves by 2026.

La Mesa

The City of La Mesa has approximately 28,000 accounts or about 20% of the three-city total. If the City of La Mesa decides to establish a standalone CCA, the costs other than those related to power supply, data management and SDG&E charges would need to be below $2 million per year. To model the scenario for La Mesa, it was assumed that the CCA would spend approximately $800,000 per year in staffing costs, another $400,000 to $500,00 in consulting costs, and under $100,000 in A&G. For the analysis, the working capital needs were reduced to $4 million and it was assumed that it would be paid off over five years. Based on this analysis, if La Mesa offers 1% discount to SDG&E bills the reserve level by 2026 would be $3.0 million. It can therefore be concluded that while La Mesa could operate a standalone CCA, the costs other than those related to power supply, data management and SDG&E charges would need to be significantly below $2 million per year in order for sufficient reserves to be accumulated.

Santee

The City of Santee has approximately 22,000 accounts or about 16% of the three-city total. If the City of Santee decides to establish a standalone CCA, the costs other than those related to power supply, data management and SDG&E charges would need to be below $2 million per year. To model the scenario for Santee, it was assumed that the CCA would spend approximately $800,000 per year in staffing costs, another $400,000 to $500,00 in consulting costs, and under $100,000 in A&G. For the analysis, the working capital needs were reduced to $3.75 million and it was assumed that it would be paid off over five years. Based on this analysis, if Santee offers 1% discount to SDG&E bills then the reserve level by 2026 would be $1.6 million. It can therefore be concluded that while Santee could operate a standalone CCA, the costs other than those related to power supply, data management and SDG&E charges would need to be significantly below $2 million per year in order for sufficient reserves to be accumulated.

Results

The Partner CCA analysis demonstrates that a three-city CCA could offer 2% rate discount. Under the separate city results, the proformas on the following pages demonstrate that the same level of savings could potentially be offered by Chula Vista, while la Mesa and Santee would only be able to reduce rates by 1% although additional cost reductions would be needed to ensure robust financial performance of the CCA.

City of Chula Vista 50% to 100% Renewable by 2035											
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Revenues from Operations ($)											
Electric Sales Revenues	$32,815,290	$49,591,297	$50,625,391	$52,082,289	$57,238,231	$59,875,890	$61,048,995	$63,033,398	$65,072,378	$67,553,287	$69,902,353
Less Uncollected Accounts	$65,631	$99,183	$101,251	$104,165	$114,476	$119,752	$122,098	$126,067	$130,145	$135,107	$139,805
Total Revenues	$32,749,660	$49,492,114	$50,524,140	$51,978,124	$57,123,754	$59,756,139	$60,926,897	$62,907,331	$64,942,233	$67,418,181	$69,762,548
Cost of Operations ($)											
Cost of Energy	$28,115,313	$41,643,073	$43,285,459	$45,640,150	$47,252,259	$49,097,973	$50,786,963	$52,470,939	$54,191,399	$56,133,680	$58,776,797
Operating & Administrative											
Billing & Data Management	$993,785	$1,385,629	$1,422,104	$1,459,539	$1,497,960	$1,537,393	$1,577,863	$1,619,399	$1,662,028	$1,705,779	$1,750,682
SDG&E Fees	$413,101	$239,089	$245,383	$251,842	$258,472	$265,276	$272,259	$279,426	$286,781	$294,330	$302,078
Consulting Services	$1,170,300	$1,747,668	$1,517,319	$1,547,666	$1,578,619	$1,610,191	$1,642,395	$1,675,243	$1,708,748	$1,742,923	$1,777,781
Staffing	$1,612,863	$1,891,994	$1,929,834	$1,968,430	$2,007,799	$2,047,955	$2,088,914	$2,130,692	$2,173,306	$2,216,772	$2,261,108
General & Administrative expenses	$219,963	$160,430	$163,638	$166,911	$272,249	$173,654	$177,127	$180,670	$286,283	$187,969	$191,728
Debt Service	$1,141,710	$1,245,501	$1,245,501	$1,245,501	$1,245,501	$0	$0	$0	$0	$0	$0
Total O&A Costs	$5,551,722	$6,670,310	$6,523,779	$6,639,890	$6,860,601	$5,634,469	$5,758,558	$5,885,430	$6,117,146	$6,147,774	$6,283,378
Total Cost	$33,667,035	$48,313,383	$49,809,239	$52,280,041	$54,112,860	$54,732,442	$56,545,521	$58,356,369	$60,308,546	$62,281,454	$65,060,175
Net Income from Operations	($917,375)	$1,178,731	$714,902	($301,916)	$3,010,895	$5,023,696	$4,381,376	$4,550,962	$4,633,687	$5,136,727	$4,702,373
Cash from Operations and Financing											
Net Income	($917,375)	$1,178,731	$714,902	($301,916)	$3,010,895	$5,023,696	$4,381,376	$4,550,962	$4,633,687	$5,136,727	$4,702,373
Cash from Financing	$5,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cash Available	$4,582,625	$1,178,731	$714,902	($301,916)	$3,010,895	$5,023,696	$4,381,376	$4,550,962	$4,633,687	$5,136,727	$4,702,373
Net Income Allocation											
Working Capital Repayment (Remainder)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs/Additional Rate Savings	$0	$0	$0	$0	$0	$0	$0	$1,751,624	$4,633,687	$5,136,727	$4,702,373
Total Reserve Outlays	$0	$0	$0	$0	$0	$0	$0	$1,751,624	$4,633,687	$5,136,727	$4,702,373
Rate Stabilization Reserve Balance	**$4,582,625**	**$5,761,356**	**$6,476,258**	**$6,174,342**	**$9,185,236**	**$14,208,933**	**$18,590,308**	**$21,389,647**	**$21,389,647**	**$21,389,647**	**$21,389,647**
CCA Total Bill	$144,339,355	$196,767,567	$201,947,277	$207,263,125	$216,706,093	$223,357,110	$228,265,476	$234,274,337	$240,441,374	$246,770,753	$253,266,746
SDG&E Total Bill	$147,285,057	$200,783,232	$206,068,650	$211,493,201	$221,128,738	$226,949,731	$232,923,955	$239,055,446	$245,348,341	$251,806,891	$258,435,456
Difference	$2,945,701	$4,015,665	$4,121,373	$4,230,076	$4,422,645	$3,592,620	$4,658,479	$4,781,109	$4,906,967	$5,036,138	$5,168,709
Savings	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%

City of La Mesa 50% to 100% Renewable by 2035											
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Revenues from Operations ($)											
Electric Sales Revenues	$11,269,777	$16,666,794	$17,026,515	$17,513,453	$19,187,573	$19,751,294	$20,451,809	$21,110,106	$21,786,554	$22,604,120	$23,380,302
Less Uncollected Accounts	$22,540	$33,334	$34,053	$35,027	$38,375	$39,503	$40,904	$42,220	$43,573	$45,208	$46,761
Total Revenues	$11,247,237	$16,633,460	$16,992,462	$17,478,426	$19,149,198	$19,711,791	$20,410,906	$21,067,886	$21,742,981	$22,558,911	$23,333,542
Cost of Operations ($)											
Cost of Energy	$9,232,873	$13,417,629	$13,935,668	$14,676,986	$15,193,853	$15,788,223	$16,328,261	$16,866,969	$17,417,694	$18,039,687	$18,885,651
Operating & Administrative											
Billing & Data Management	$318,883	$444,547	$456,249	$468,259	$480,586	$493,237	$506,221	$519,546	$533,223	$547,260	$561,666
SDG&E Fees	$155,819	$76,706	$78,725	$80,798	$82,925	$85,108	$87,348	$89,647	$92,007	$94,429	$96,915
Consulting Services	$818,400	$1,191,054	$1,082,224	$1,103,869	$1,125,946	$1,148,465	$1,171,434	$1,194,863	$1,218,760	$1,243,135	$1,267,998
Staffing	$800,265	$772,730	$788,185	$803,949	$820,028	$836,428	$853,157	$870,220	$887,624	$905,377	$923,484
General & Administrative expenses	$158,763	$160,430	$163,638	$166,911	$211,049	$173,654	$177,127	$180,670	$225,083	$187,969	$191,728
Debt Service	$830,334	$905,819	$905,819	$905,819	$905,819	$0	$0	$0	$0	$0	$0
Total O&A Costs	$3,082,465	$3,551,286	$3,474,841	$3,529,605	$3,626,353	$2,736,892	$2,795,287	$2,854,946	$2,956,698	$2,978,170	$3,041,791
Total Cost	$12,315,337	$16,968,915	$17,410,509	$18,206,591	$18,820,205	$18,525,114	$19,123,548	$19,721,915	$20,374,392	$21,017,857	$21,927,442
Net Income from Operations	($1,068,100)	($335,455)	($418,047)	($728,165)	$328,993	$1,186,677	$1,287,358	$1,345,971	$1,368,589	$1,541,055	$1,406,099
Cash from Operations and Financing											
Net Income	($1,068,100)	($335,455)	($418,047)	($728,165)	$328,993	$1,186,677	$1,287,358	$1,345,971	$1,368,589	$1,541,055	$1,406,099
Cash from Financing	$4,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cash Available	$2,931,900	($335,455)	($418,047)	($728,165)	$328,993	$1,186,677	$1,287,358	$1,345,971	$1,368,589	$1,541,055	$1,406,099
Net Income Allocation											
Working Capital Repayment (Remainder)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs/Additional Rate Savings	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,299,852	$1,406,099
Total Reserve Outlays	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,299,852	$1,406,099
Rate Stabilization Reserve Balance	**$2,931,900**	**$2,596,445**	**$2,178,398**	**$1,450,232**	**$1,779,225**	**$2,965,902**	**$4,253,260**	**$5,599,230**	**$6,967,819**	**$7,209,022**	**$7,209,022**
CCA Total Bill	$47,257,155	$63,794,100	$65,473,415	$67,196,938	$70,243,137	$72,092,217	$73,989,973	$75,937,685	$77,936,747	$79,988,354	$82,093,719
SDG&E Total Bill	$47,734,452	$64,438,484	$66,134,763	$67,875,695	$70,952,664	$72,820,421	$74,737,346	$76,704,732	$78,723,908	$80,796,236	$82,923,116
Difference	$477,297	$644,385	$661,348	$678,757	$709,527	$728,204	$747,373	$767,047	$787,160	$807,882	$829,397
Savings	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

City of Santee 50% to 100% Renewable by 2035											
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Revenues from Operations ($)											
Electric Sales Revenues	$10,135,375	$14,726,126	$15,047,950	$15,494,380	$16,801,076	$17,298,784	$17,915,992	$18,458,813	$19,013,840	$19,687,817	$20,321,555
Less Uncollected Accounts	$20,271	$29,452	$30,096	$30,989	$33,602	$34,598	$35,832	$36,918	$38,028	$39,376	$40,643
Total Revenues	$10,115,104	$14,696,674	$15,017,854	$15,463,391	$16,767,474	$17,264,186	$17,880,160	$18,421,895	$18,975,812	$19,648,441	$20,280,912
Cost of Operations ($)											
Cost of Energy	$8,297,665	$11,799,161	$12,244,028	$12,883,964	$13,335,750	$13,857,618	$14,328,855	$14,798,952	$15,279,688	$15,823,104	$16,562,796
Operating & Administrative											
Billing & Data Management	$248,492	$346,280	$355,395	$364,750	$374,352	$384,207	$394,320	$404,701	$415,354	$426,288	$437,509
SDG&E Fees	$128,968	$59,750	$61,323	$62,937	$64,594	$66,294	$68,040	$69,831	$71,669	$73,556	$75,492
Consulting Services	$818,400	$1,191,054	$1,082,224	$1,103,869	$1,125,946	$1,148,465	$1,171,434	$1,194,863	$1,218,760	$1,243,135	$1,267,998
Staffing	$800,265	$772,730	$788,185	$803,949	$820,028	$836,428	$853,157	$870,220	$887,624	$905,377	$923,484
General & Administrative expenses	$158,763	$160,430	$163,638	$166,911	$211,049	$173,654	$177,127	$180,670	$225,083	$187,969	$191,728
Debt Service	$778,438	$849,206	$849,206	$849,206	$849,206	$0	$0	$0	$0	$0	$0
Total O&A Costs	$2,933,326	$3,379,449	$3,299,971	$3,351,622	$3,445,175	$2,609,048	$2,664,078	$2,720,284	$2,818,491	$2,836,324	$2,896,212
Total Cost	$11,230,991	$15,178,610	$15,543,999	$16,235,586	$16,780,924	$16,466,667	$16,992,934	$17,519,236	$18,098,178	$18,659,429	$19,459,008
Net Income from Operations	($1,115,887)	($481,936)	($526,145)	($772,195)	($13,450)	$797,520	$887,226	$902,660	$877,634	$989,013	$821,904
Cash from Operations and Financing											
Net Income	($1,115,887)	($481,936)	($526,145)	($772,195)	($13,450)	$797,520	$887,226	$902,660	$877,634	$989,013	$821,904
Cash from Financing	$3,750,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cash Available	$2,634,113	($481,936)	($526,145)	($772,195)	($13,450)	$797,520	$887,226	$902,660	$877,634	$989,013	$821,904
Net Income Allocation											
Working Capital Repayment (Remainder)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs/Additional Rate Savings	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Reserve Outlays	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Rate Stabilization Reserve Balance	**$2,634,113**	**$2,152,176**	**$1,626,032**	**$853,837**	**$840,387**	**$1,637,906**	**$2,525,133**	**$3,427,792**	**$4,305,426**	**$5,294,438**	**$6,116,343**
CCA Total Bill	$42,304,510	$56,391,240	$57,864,262	$59,407,068	$61,926,752	$63,560,277	$65,234,882	$66,916,812	$68,640,273	$70,403,849	$72,211,520
SDG&E Total Bill	$42,731,872	$56,842,276	$58,338,593	$59,874,298	$62,561,127	$64,207,986	$65,898,197	$67,632,901	$69,413,270	$71,240,505	$73,115,840
Difference	$427,361	$451,037	$474,331	$467,230	$634,375	$647,709	$663,315	$716,089	$772,997	$836,655	$904,320
Savings	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%