Community Choice Energy for the City of Huntington Beach and Review of Orange County Power Authority

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This report was prepared by MRW & Associates. MRW has been working on Community Choice Aggregation (CCA) issues since they were authorized by the California State Legislature in 2002. MRW has prepared and critiqued numerous CCA feasibility plans and is providing rate forecasting and other ongoing support to CCAs throughout the state.

This Study is based on the best information available at the time of its preparation, using publicly available sources for all assumptions to provide an objective assessment regarding the prospects of CCA operation in the City. It is important to keep in mind that the findings and recommendations reflected herein are substantially influenced by current market conditions within the electric utility industry and state regulations, both of which are subject to sudden and significant changes.

Table of Contents

List of Acronyms

AB	Assembly Bill
BNI	Binding Notice of Intent
C&I	Commercial and Industrial
CAISO	California Independent System Operator
Cal-CCA	California Community Choice Association
CCA	Community Choice Aggregator/Aggregation
CCEA	California Choice Energy Authority
CEC	California Energy Commission
CO2e	Carbon Dioxide Equivalent
CPA	Clean Power Alliance
CPUC	California Public Utilities Commission
CRS	Cost Responsibility Surcharge
CTC	Competition Transition Charge
DA	Direct Access
DEG	Distributed Energy Generation
DOE	Department of Energy
EE	Energy Efficiency
ESP	Energy Service Provider
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FiT	Feed-in-Tariff
GGRP	Greenhouse Gas Reduction Program
GHG	Greenhouse Gas
GTSR	Green Tariff Shared Renewable
GTSR-GR	Green Tariff Shared Renewable - Green Rate
GWh	Gigawatt Hour
IOU	Investor-Owned Utility
IRP	Integrated Resource Planning
kW	Kilowatt
kWh	Kilowatt Hour
LSE	Load Serving Entity
MCE	Marin Clean Energy

MT	Metric Ton
MWh	Megawatt Hour
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OCPA	Orange County Power Authority
PCIA	Power Charge Indifference Adjustment
PG&E	Pacific Gas & Electric
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
PPP	Public Purpose Program
PSPS	Public Safety Power Shutoffs
PV	Photovoltaic
RA	Resource Adequacy
REC	Renewable Energy Credit
RFP	Request for Proposal
RPS	Renewable Portfolio Standard
SB	Senate Bill
SC	Scheduling Coordinator
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SJCE	San Jose Clean Energy
SVCEA	Silicon Valley Clean Energy Authority

Executive Summary

The City of Huntington Beach (the City) is currently a member city of the Orange County Power Authority (OCPA) Community Choice Aggregation (CCA) program but has the option to withdraw from the JPA within a certain timeframe and with no consequences. The City requested MRW & Associates (MRW) to provide an independent analysis of OCPA's financial viability, to review the OCPA Implementation Plan, and to provide an analysis of the risks the City would face if it remained in the OCPA.

Main Findings

The general conclusions of this study are as follows:

1. MRW's independent analysis performed here finds that the OCPA CCA program is projected to be financially feasible. That is, over the long run the CCA would likely be able to offer Orange County residents and businesses power that is priced at or a few percent lower than that offered by Southern California Edison (SCE).
2. The financial margins are smallest during the first years of operation, due to the initial investment in startup costs, loan repayments, and SCE rates. As such, OCPA's targeted rate discount of 2% may not be achievable during the first years of operation; however, beyond 2023, OCPA's rates should be lower than SCE's rates.
3. While feasible, CCA formation is not risk-free. OCPA will be participating in a competitive power market and subject to evolving state requirements and regulations. While an OCPA rate discount in the long run should be achievable, market prices and SCE rate volatility could combine to, in some isolated years, occasionally prevent the CCA from offering lower rates than SCE.
4. The financial analysis underlying OCPA's Implementation Plan is generally sound. That is, the underlying customer phase-in, assumed power prices, operating costs, and CCA revenues are all reasonable or conservative. Our primary concern with the Implementation Plan is with the financing assumptions, which may be understating OCPA's initial working capital requirement.
5. OCPA's Joint Powers Agreement specifically states that the debts of the OCPA cannot be transferred to its member cities, nor can the OCPA compel a member city to financially contribute to the OCPA. As such, the City's General Fund should not be impacted by joining OCPA, nor would its membership negatively impact the City's credit rating or ability to borrow.[1] If Huntington Beach chose to form a stand-alone CCA enterprise, the City would have to provide a short-term loan to the CCA enterprise and provide a financial guarantee that provides the start-up capital to the CCA. As a member

[1] Note that MRW is not a law firm and that these conclusions do not represent a legal opinion, only a laymen's reading of the JPA document.

of OCPA, these financial burdens are being met by Irvine and are therefore not applicable to Huntington Beach.

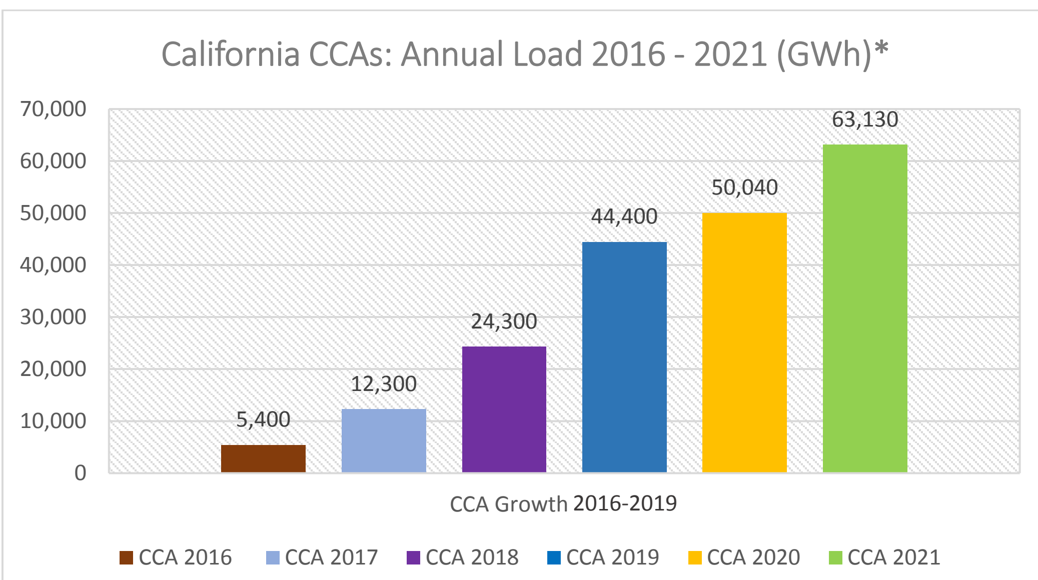
6. Forming a CCA does not guarantee greenhouse gas (GHG) savings. Achieving GHG reductions requires the CCA to do more than just meet the state renewable requirements; it requires the CCA to either acquire energy from large hydroelectric facilities (which are carbon-free but do not qualify as "renewable" under State law) or increase the renewable content of its electricity supply beyond that required by the State.

CCA Background

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure and provide electric power for their residents and businesses. Under existing rules administered by the California Public Utilities Commission (CPUC) an investor-owned utility (IOU), such as Southern California Edison (SCE), must use its transmission and distribution system to deliver the electricity supplied by a CCA in a non-discriminatory manner. That is, it must provide these electricity delivery services at the same price and at the same level of reliability to customers supplied by a CCA as it does for its own full-service customers.

CCAs are now quite common in California. There are currently 23 CCAs providing power in the State, with at least another half-dozen planning on doing so in the next two years. As shown in Figure ES-1, CCAs are expected to serve over 63 GWhs in the State by the end of 2021, with some projecting that by the mid-2020s between 50 to 80 percent of the load in the three main IOU service territories will be served by non-utility entities (CCAs and Direct Access providers).

Figure ES-1. California CCA Load Growth



*Source: Cal-CCA. Values for 2020 and 2021 are estimates.

Huntington Beach and OCPA's Electric Loads

Table ES-1 shows that OCPA's total annual electric load in 2019 is about 4,500 GWh with 1,000 GWh of that load coming from Huntington Beach. OCPA has over 330,000 customer accounts, of which 86,000 (23%) are in Huntington Beach. For comparison, Irvine's load will make up about 42% of OCPA's, load, Fullerton 15% and Lake Forest and Buena Park each at 10%.

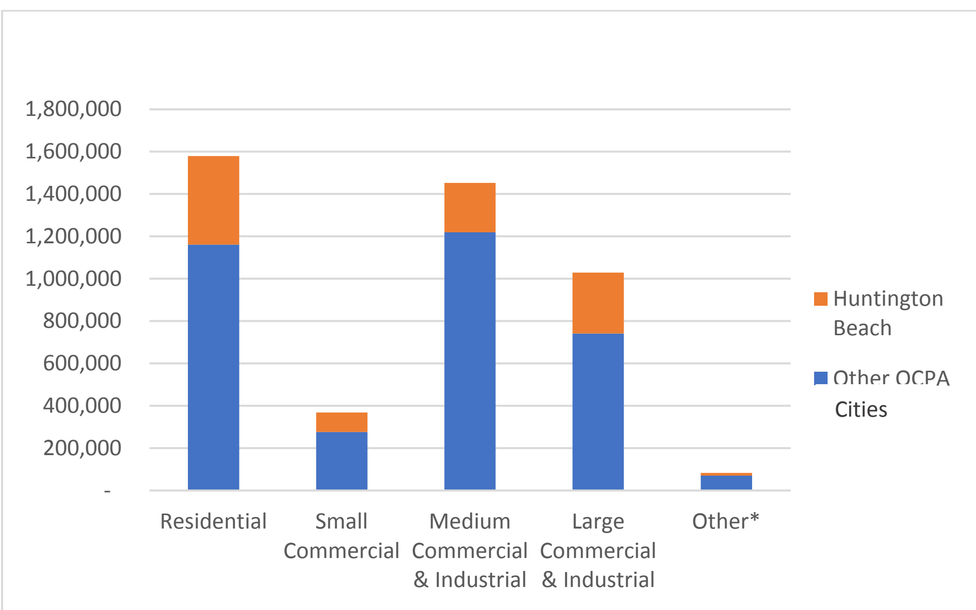
Table ES-1. Potential OCPA Customers and Associated Load

	Huntington Beach		OCPA (Total)	
	Customers	Annual Load (MWh)	Customers	Annual Load (MWh)
Residential	75,940	418,684	288,041	1,579,280
Small Commercial	8,732	92,635	32,138	368,188
Medium Commercial	1,145	233,810	6,216	1,452,384
Large Commercial & Industrial	26	287,178	191	1,028,396
Other*	539	12,833	4,032	82,769
Total	86,382	1,045,139	330,617	4,511,017

*e.g., streetlights, traffic control, agriculture/pumping.

As shown above and in Figure ES-2 below, Huntington Beach has a higher percentage of residential load compared to the other OCPA members and a lower percentage coming from small commercial and the "other" category (streetlights, pumping, and agriculture).

Figure ES-2. Huntington Beach Load Distribution

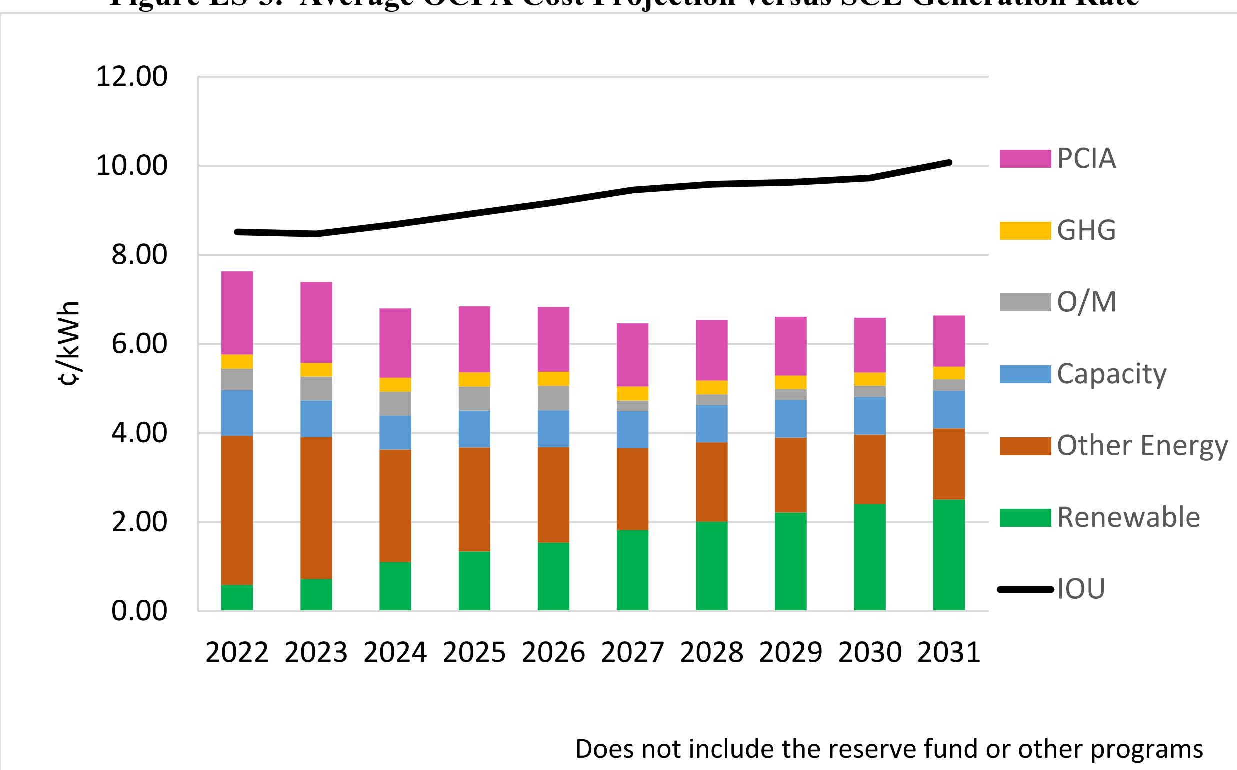


Financial Results

Figure ES-3 shows the forecast of average MRW-modeled OCPA costs and SCE's generation rates. The bars in the chart show the forecasts of the major cost components of CCA operation, while the single line shows the forecast of SCE's generation rate. When the bars are below the black line, the CCA's average operating costs will be below the SCE generation rate; meaning that it can offer power to customers at a rate lower than or competitive with SCE. As is clearly seen in the figure, the average cost of power provided by the CCA is consistently below the SCE generation rate, although much closer in the first few years of OCPA operation.

The bottom-most green segment represents the cost of renewable power to the CCA. The brown segment is for the costs of non-renewable, wholesale market power. This segment slowly decreases, as renewable power increases. (Because renewables are currently more costly than market power, the analysis assumes OCPA will initially meet the State's minimum renewable power content requirement and ramp up as the requirements increase). The light blue segment is for capacity. That is, the CCA must demonstrate that it has the generating capacity (in megawatts) to ensure that it can serve all its load. The gray segment is for debt service, operations, franchise fees, and uncollectibles. The yellow segment is for carbon cap and trade allowances. Note that for practical purposes, the cost of carbon cap-and-trade allowances would be built into the purchase price of natural gas-fired market resources. However, because it is an important variable on its own, the costs are shown separately.

Figure ES-3. Average OCPA Cost Projection versus SCE Generation Rate



The top-most pink segment is for the Power Charge Indifference Adjustment (PCIA), a fee paid to SCE to ensure that the operation of the CCA does not strand SCE's remaining bundled customers with costs associated with power purchased on behalf of customers who have shifted to the CCA.

The black line represents SCE's average generation rate. To forecast SCE's generation rates, the comparison model used information regarding SCE's utility-owned generation, power contracts, power market costs, and by closely tracking changes in SCE revenues and costs through its filings in several CPUC proceedings. In particular, it takes the most recent SCE filing of generation rates and applies the known and anticipated changes to the wholesale power market prices and SCE's power purchase contracts.

Table ES-2 shows the "margin" between the CCA's costs (including the PCIA) and SCE's generation rate (i.e., the difference between the top of the CCA cost columns and the SCE generation rate line in the above figure). The margin between the CCA's cost and SCE's generation rates need not go fully to offering rate savings. In fact, during the first few years, the CCA's set their rates so that most of the margin between their ongoing costs and SCE's generation rates is set aside for financial reserves and paying down the initial startup loans. Once the financial reserve targets are met and the start-up loans paid off, CCAs typically use a portion of the margin for programs serving their residents and businesses, purchasing greater amounts of renewable power, and providing greater rate discounts that could be offered during the first years. It is up to the CCA Board of Directors to balancing these competing uses (i.e., rate discounts, programs, financial reserves, and greener power).

Table ES-2. Projected OCPA Margins*

	2022	First 3 years (2022-24)	First 5 years (2022-2026)	2nd 5 years (2027-2031)	10-Years (2022-2031)
¢/kWh (average)	1.0	1.2	1.6	2.9	2.2

*Without rate savings, reserve contributions or program funding

Analysis Underlying the OCPA Implementation Plan

Overall, the assumptions and analysis in the Implementation Plan are sound. That is, the underlying customer phase-in, assumed power prices, operating costs, and CCA revenues are all reasonable or conservative. However, we note the following concerns. First, the Implementation Plan does not reflect the State's changing policy concerning Local Resource Adequacy. While this does not impact the overall competitiveness of the OCPA, it should be addressed in any future documents. Second, the Implementation Plan's generation rate is on average about 5% lower than MRW's projections while significantly overestimating the PCIA. The PCIA overestimation more than makes up for the low generation rate and results in a net level of conservatism in the Implementation Plan's financial position. Third, MRW believes that the Implementation Plan may be underestimating the initial working capital requirements. The Implementation plan assumes $15.5 million for starting and a working capital loan/line of credit, $2.5 million directly from the city of Irvine and $13 million from a third party. This represents about 30 days of average cash flow in the first year, in which, the phase-in is only a fraction of the load would be served. MRW's more conservative analysis assumes that the working capital loan / line of credit would be for 60 days of cash flow assuming the full load is served.

San Diego Community Power (SDCP) provides another data reference. OCPA's load is projected to be about 62% of that of SDCP. SDCP required $40 million initial line of credit. Simply scaling SDCP's requirement down to OCPA suggests an initial bank load/line of credit around $25 million.

We note that Irvine has agreed to provide up to $5 million collateral and a loan guarantee if required for the power purchase loan requirements. (Exhibit D, section 1.3 of the JPA agreement). While Irvine's commitment may provide sufficient backstop for OPCA financing, it cannot be known until OCPA secures financing.

Risks and Risk Management

The primary risk faced by a CCA is that it cannot provide power to its residents and businesses at a competitive price. (Many of the factors that can impact the CCA's price position are explored in the sensitivity analyses). This risk is caused not only by changes to the power market but also changing regulatory requirements SCE. The primary way that a CCA can address these risks is to use sound power procurement and risk management practices. While complex, these practices are well known and implementable.

The risk of joining OCPA to the City's general fund is minimal. OCPA's Joint Powers Agreement specifically states that the debts of the OCPA cannot be transferred to its member cities, nor can the OCPA compel a member city to financially contribute to the OCPA. As such, the City's General Fund should not be impacted by joining OCPA, nor would its membership negatively impact the City's credit rating or ability to borrow.[2] If Huntington Beach chose to form a stand-alone CCA enterprise, the City would have to provide a short-term loan to the CCA enterprise and provide a financial guarantee to the bank or other financial institution that provides the start-up capital to the CCA. As a member of OCPA, these financial burdens are being met by Irvine and are therefore not applicable to Huntington Beach.

[2] Note that MRW is not a law firm and that these conclusions do not represent a legal opinion, only a laymen's reading of the JPA document.

Chapter 1. Introduction

What is a CCA?

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure and provide electric power for their residents and businesses.

Under existing rules administered by the California Public Utilities Commission, an investor-owned utility (IOU) must use its transmission and distribution system to deliver the electricity supplied by a CCA in a non-discriminatory manner. That is, it must provide these delivery services at the same price and at the same level of reliability to customers supplied by a CCA as it does for its own full-service customers. By state law, an IOU also must provide all metering and billing services, its customers receiving a single electric bill each month from the IOU, which would differentiate the charges for generation services provided by the CCA as well as charges for IOU delivery services. Money collected by the IOU on behalf of the CCA must be remitted in a timely fashion (e.g., within 3 business days).

As a power provider, the CCA must abide by the rules and regulations placed on it by the state and its regulating agencies, such as maintaining demonstrably reliable supplies and fully cooperating with the State's power grid operator. However, the State has no rate-setting authority over the CCA; the CCA may set rates as it sees fit so as to best serve its constituent customers. This is in contrast to SCE, which require approval by the California Public Utility Commission to set its rates.

Per California law, when a CCA is formed all the electric customers within its boundaries will be placed, by default, onto CCA service. However, customers retain the right to return to SCE service at will, subject to whatever administrative fees the CCA may choose to impose—typically $5 for a residential customer and $25 for a non-residential customer.

Possible OCPA Objectives

The feasibility of a CCA program is a function of that program's ability to meet the sponsoring city's or JPA's goals and objectives. This section lays out the typical CCA goals and objectives and how they might apply to Huntington Beach.

Rate Competitiveness and Financial Stability

OCPA has set a goal to offer rates that are competitive with the projected generation rates offered by the incumbent electric utility, Southern California Edison (SCE). "Competitive" here means that the CCA, over the long run, could offer rates that are equal to or less than those offered by SCE. It does not mean that in every year a specific rate savings is offered. In fact, some CCAs have had to offer rates slightly higher than those offered by their host utilities during one or more of their first few years. We note that they did not experience significant opt-outs because of this.

In addition, the CCA would be committed to providing equitable treatment of all classes of customers without undue discrimination in setting rates. At the same time, the rates would have to generate sufficient revenue to the CCA, so all liabilities are covered in a manner consistent with an investment-grade entity. The CCA should not move forward unless there is confidence that both rate competitiveness and financial stability can be achieved.

The CCA would also intend to offer long-term rate stability to its customers as well as maintain its own financial condition. This could be accomplished through conservative phasing in of customers and projects; establishing and maintaining appropriate lines of credit and financial reserves; and contracting with only experienced and financially solid providers of goods and services.

Contribute to Greenhouse Gas Reduction Program Objectives

In October 2017, the City of Huntington Beach updated its General Plan to include a Greenhouse Gas Reduction Program (GGRP), which includes greenhouse gas (GHG) emissions reduction targets and general emissions reduction strategies. As discussed later, a CCA, if it is financially able and so chooses, can contribute to the City meeting its GGRP objectives.

It must be noted that California is moving toward a carbon-free electricity policy. Senate Bill 100, which was signed into law by Governor Brown on September 17, 2018, increases the renewable power content requirement of all retail power providers, including utilities and CCAs, from 50% to 60% by 2030. The bill also says, "that it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045," and that all state agencies regulating electricity build this goal into their planning. This effectively means that the difference between the electricity carbon content of the CCA following the City's GGRP and remaining with status quo utility service may not be significant.

Additional Objectives

While maintaining rate competitiveness, financial stability, and contributing to the City's GGRP are non-negotiable objectives, a CCA can also serve as a vehicle to pursue other objectives that benefit the

CCA and SCE Rates

A CCA provides only generation services: the actual power that CCA customers use. The incumbent utility, SCE, would still deliver the power to the home or business, even though the CCA is providing the power.

Therefore, the CCA customer would still pay the SCE delivery rates, but instead of paying SCE's generation rates, they would pay the CCA's generation rates. CCA customers also pay an additional fee so that the remaining SCE customers are not harmed by the CCA (the "PCIA" charge).

Because a customer pays the same delivery rates no matter who provides their power, the rate comparisons here focus on the CCA rate (plus the PCIA charge) versus SCE's generation rate.

City, its residents, and businesses. Examples of additional objectives could include the following:

Economic development. A CCA can potentially contribute to local economic development in two ways. First, if the CCA offers reduced electricity rates, additional dollars can flow into the local economy as households and businesses spend their incomes on items and services other than electricity. Second, the CCA can offer programs that allow households and businesses to reduce their power consumption, such as energy efficiency and distributed energy resources.

Local jobs and employment. Beyond the potential jobs that could result from the economic stimulus of possibly lower rates, the CCA can more directly incentivize and support local job creation. This includes employing residents in CCA administration, using local contractors for energy efficiency programs, and distributed energy generation (e.g., rooftop solar installers and maintainers). The CCA can also partner with local community colleges and/or trades apprenticeship programs to support quality local job opportunities.

Prioritization of renewable power development. Beyond support of locally sited distributed energy generation ("DEG," e.g., rooftop solar), a CCA may prioritize siting larger, grid connected DEG and utility-scale renewable project locally.

Local citizen input and participation. A primary purpose of a CCA is to better reflect its community's interests and values than a large-scale, investor-owned utility like SCE can. This is illustrated in the CCA's objective of supporting the City's GGRP. However, it can go beyond this; the CCA can commit to creating opportunities for citizens to provide input into its programs and policies.

Power primer

The California Independent System Operator (CAISO) manages the balance between electricity load and supply on its system for both CCAs and IOUs. Each utility, CCA or energy service provider (ESP) on the CAISO system provides, each day, a forecast of its load and the resources it will be using to meet that load. These load serving entities' (LSEs) forecasts are updated throughout the day by the LSE's "scheduling coordinator." The CAISO also maintains markets for power plants to be standing by to meet unexpected load, or to back off production if load is lower than forecasted.

For LSE planning and procurement purposes, electricity supply consists of two components: energy in kilowatt hours (kWh), and capacity or demand in kilowatts (kW). Using an analogy of a railroad car: the size of the car represents capacity; and the goods inside the car represent energy. A CCA must purchase both energy (kWh) to meet its customer's consumption needs and capacity to account for customer demand. The CCA must always purchase both the correct amount of energy (kWh) and an adequate amount of capacity to meet its customers' energy requirements. As such, the CCA must appropriately forecast both the energy usage (kWh) and peak demand (kW) requirements of its customers.

Reaching CCA Objectives

Financial

As noted above, OCPA would expect to offer rates that are competitive with those offered by SCE. At the same time, the rates would have to generate sufficient revenue for the CCA so that all liabilities are covered in a matter consistent with an investment-grade entity. The CCA would not move forward unless there is confidence that both rate competitiveness and financial stability can be achieved.

The CCA would also intend to offer long-term rate stability to its customers as well as maintain its own financial condition. This will be accomplished through conservative phasing in of customers and projects; establishing and maintaining appropriate lines of credit and financial reserves; and contracting with only experienced and financially solid providers of goods and services.

We assume that OCPA would be a financially independent enterprise with no funds or debts co-mingling with City of Huntington Beach or any other member's, General Fund. It will establish reserve funds commensurate with the working capital, operating reserves, and contingency requirements of the enterprise. To do so, the CCA would have to develop a rate design that recovers sufficient revenue to adequately fund these reserves in the intermediate term.

Climate Change Mitigation

As noted above, the City has included the GGRP in its General Plan. According to the GGRP, the mission for the reduction plan is to:

- Quantify greenhouse gas emissions, both existing and projected over a specified time period, resulting from activities within a defined geographic area.
- Establish a level, based on substantial evidence, below which the contribution to greenhouse gas emissions from activities covered by the plan would not be cumulatively considerable.
- Identify and analyze the greenhouse gas emissions resulting from specific actions or categories of actions anticipated within the geographic area.
- Specify measures or a group of measures, including performance standards, that substantial evidence demonstrates, if implemented on a project-by-project basis, would collectively achieve the specified emissions level.
- Establish a mechanism to monitor the plan's progress toward achieving the level and to require amendment if the plan is not achieving specified levels.[3]

Through the GGRP, as well as existing actions taken by the City of Huntington Beach, the City has set a GHG emissions target of 570 metric tons (MT) CO2e by 2040. This target value

[3] City of Huntington Beach General Plan, October, 2, 2017.

signifies a large reduction from the estimated future GHG emissions value of 66 MT CO2e in 2040 if the GGRP and existing reduction actions are not utilized.[4]

To the extent that the carbon content of the power provided by the CCA is lower than that provided by SCE, the CCA can contribute to meeting the GGRP's 2040 aspiration.

Renewables – What Does It Mean to be 100% Green?

Most CCAs offer rate options to customers that are "100% Green;" that is, the power consumed by customers on these rates is fully provided by qualifying renewable resources. Other CCAs have a goal of being 100% Green by a certain date (e.g., the newly formed San Diego Community Power intends to be fully green by 2035). The ability of a CCA or a customer to rely fully on renewable power is accurate within the framework of power procurement, but not necessarily transparent to the lay audience.

When a CCA is sourced fully by renewable power, it does not mean that for each hour of the day, 100% of the power injected into the California power grid by the CCA (that is, by the renewable generators owned or under contract to the CCA) will be renewable. There will be hours of the day where the CCA's solar resources will be generating more electricity than the CCA's customers are consuming. This power is sold into the CAISO's wholesale market. There will also be hours of the day when the CCA's load is greater that their renewable resources' output, at which point they purchase power from the CAISO wholesale market. Currently, to be 100% renewable, the CCA's renewable resources would need to generate as much power as the CCA's customers consume, albeit not necessarily at the same time. This is analogous to the "net-zero" energy home, where, over the course of a year, the solar panels on the house generate in total as much (or more) power than the house uses, but with some hours having the solar panels inject power into the grid while in others it takes power from the grid.

In the long run, in the late 2020s and beyond, the "balancing" function of the non-renewable generators in the wholesale market will likely be replaced in part with energy storage systems, such as pumped hydroelectric or batteries. At the point when fossil resources are not needed, one can say that the CCA—and the California Grid—is 100% renewable/carbon free.

How are CCAs financially competitive with the utilities?

All but two active CCAs in California currently offer rates that are at or lower than their incumbent utility, be it SCE, Pacific Gas & Electric (PG&E) or San Diego Gas & Electric (SDG&E). CCAs' ability to do this, even with the exit fees (PCIA), is attributable to three factors. First, the CCAs serving coastal areas do not have to serve as much air conditioning load as their incumbent utilities as a whole. (SCE also serves inland regions that are much warmer than coastal areas, while coastal CCAs do not.) Because air conditioning loads often occur at the times of the day with the highest priced wholesale power, they are more costly to serve.

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[4] *General Plan Update: Program Environmental Impact Report*, Prepared by Atkins for the City of Huntington Beach, August 2017.

Second, the incumbent utilities have in their portfolios some relatively expensive, generally renewable, power purchase contracts. This raises the utilities' rates, but also begs the question of what happens when those contracts expire. Two things happen. First, the Power Change Indifference Amount (PCIA) fee is reduced because it is the mechanism to capture the above-market costs of these expensive power contracts and pass them on to customers who were on utility service when the contracts were signed. Second, at worst, the utility will be participating equally in the same wholesale power and renewable markets as the CCA.

Third, the incumbent utilities are still under the jurisdiction of the California Public Utilities Commission (CPUC). This means that each and every power purchase contract the utility enters into goes through a cumbersome vetting process and must be approved by the full CPUC. Furthermore, the utilities must often comply with non-economic directives from the CPUC, which is why they have the expensive contracts in their portfolio in the first place. CCA procurement is not so tightly bound by the state; they can be nimbler in responding to market movement and have much greater control over their purchasing, hedging, and risk management than the incumbent utilities. It is these latter points that give the existing CCAs confidence that they will be able to compete even after the higher-priced contracts in the incumbent utilities' portfolios expire.

Status of CCAs in California

Even though the enabling legislation was enacted in 2002, the first CCA to provide power, Marin Clean Energy (MCE), did not enroll customers until 2010. For the next five years, others investigated CCA formation, with a few early adopters stepping up in 2014 through 2016. As shown in Figure 1, once these early adopters showed that CCAs could work, the flood gates opened in 2017. By the end of 2021, CCAs are expected to serve over 63 GWhs, with some projecting that by the mid-2020s between 50 to 80 percent of the load in the three main IOU service territories will be served by non-utility entities (CCAs and Direct Access providers).

Figure 1. California CCA Load Growth

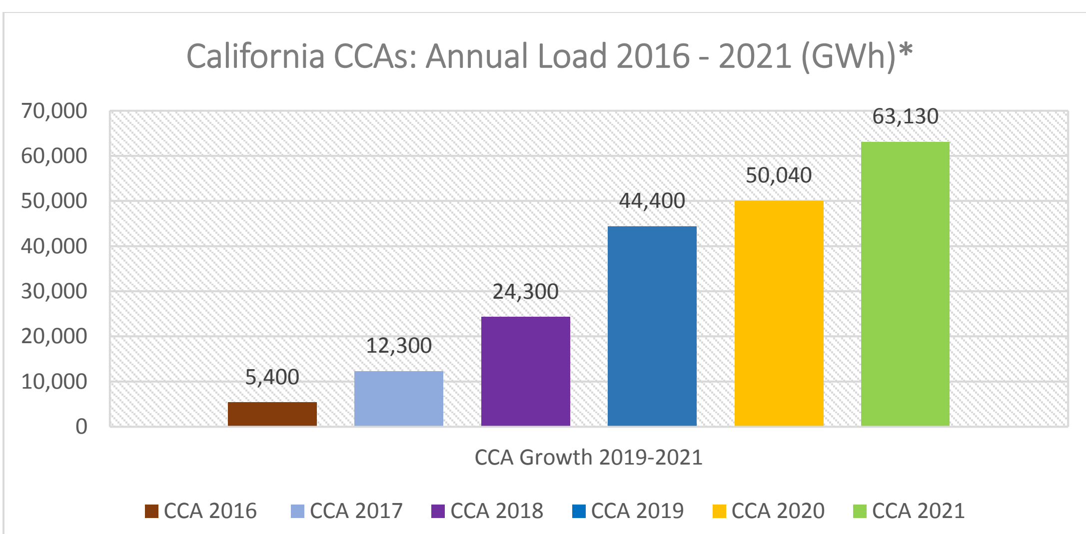


Table 1 lists the active CCAs in California, including those that have announced intended launches in 2021, along with their location and governance structure. As the table shows, most of the current CCAs are in PG&E's service area, but the growth in 2020 came from new CCAs in SCE's territory. Currently, there is only one small CCA in SDG&E's territory, Solana Energy Alliance, but two large JPAs in the San Diego region are intending to begin service in 2021.

The table also shows that the majority of CCAs are organized as joint powers authorities (JPAs). There are also many smaller cities in SCE's area that use the "JPA Light" model, in which the CCA is technically a city enterprise that relies upon the California Choice Energy Authority (CCEA) to provide the technical operations. There are also three stand-alone city CCA enterprises, King City, San Francisco, and San Jose.

Table 1. CCAs in California

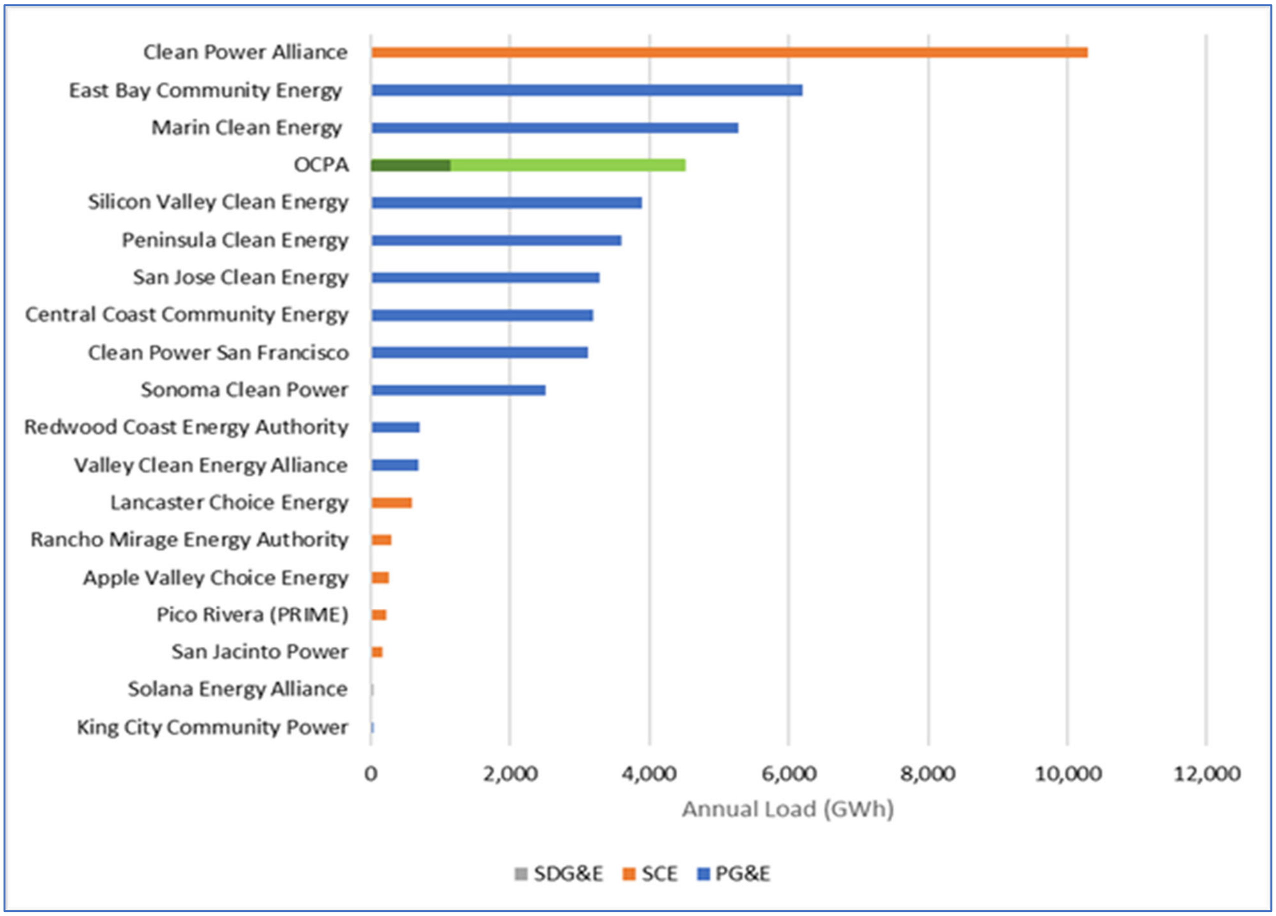
CCA	IOU	Type	Formed	Load, GWh[5]
CCAs Currently Delivering Power in California				
Clean Power San Francisco	PG&E	City	May 2016	3,135
East Bay Community Energy	PG&E	JPA	Jan.2018	6,200
Marin Clean Energy	PG&E	JPA	May 2010	5,275
Central Coast Community Energy (formerly Monterey Bay Community Power)	PG&E	JPA	March 2018	3,202
Peninsula Clean Energy	PG&E	JPA	Oct. 2016	3,600
Pioneer Community Energy	PG&E	JPA	2018	NA
Redwood Coast Energy Authority	PG&E	JPA	May 2017	699
San Jose Clean Energy	PG&E	City	Sept. 2018	3,286
Silicon Valley Clean Energy	PG&E	JPA	April 2017	3,898
Sonoma Clean Power	PG&E	JPA	May 2014	2,502
Valley Clean Energy Alliance	PG&E	JPA	Dec. 2016	682
King City Community Power	PG&E	City	July 2018	35
Clean Power Alliance	SCE	JPA	Feb. 2018	10,295
Apple Valley Choice Energy	SCE	City; CCEA	April 2017	260
Lancaster Choice Energy	SCE	City; CCEA	May 2015	600
Pico Rivera Innovative Muni'l Energy	SCE	City; CCEA	Sept. 2017	220
Rancho Mirage Energy Authority	SCE	City; CCEA	May 2018	300
San Jacinto Power	SCE	City; CCEA	April 2018	170

[5] 2019 Load (GWh) reported by CalCCA: https://cal-cca.org/cca-impact/

CCA	IOU	Type	Formed	Load, GWh[5]
Desert Community Energy	SCE	JPA	April 2020	640
Western Community Energy	SCE	JPA	April 2020	1,285
Baldwin Park	SCE	City; CCEA	Oct. 2020	255
Pomona	SCE	City; CCEA	Oct. 2020	655
Solana Energy Alliance	SDG&E	City	June 2018	37
Planned Launch				
Palmdale	SCE	City; CCEA	2021	655
Hanford	PG&E	City; CCEA	2021	285
Commerce	SCE	City; CCEA	2021	460
Drafted Ordinances for Implementation as Soon as 2021				
San Diego Community Power	SDG&E	JPA	2021	6,800
North SD County CCA	SDG&E	JPA	2021	2,750
Butte County	PG&E	JPA	2021	1,080

Figure 2 shows the 2019 annual loads of several active California CCAs. Three observations can be made from this figure. First, Clean Power Alliance (CPA), the CCA that serves Los Angeles and Ventura counties along with selected communities therein, is the largest CCA in California by load—nearly twice the size of the second largest CCA, East Bay Community Energy. Second, were Huntington Beach to join OCPA, OCPA would be one of the largest CCAs in California by load, indicating that economies of scale would have been reached. Third, Huntington Beach's load would make up almost a quarter of OCPA's total load (dark green segment of the OCPA bar).

Figure 2. California Active CCA Loads (Annual GWhs, 2020)



CCA Evolution

Over the first years of operation, many California CCAs have been evolving from a simple commodity procurement entity—providing power, albeit greener, at a competitive rate. After a year or two (or more), many CCAs have expanded into providing targeted and specialized customer programs that while customized for their communities, are variations of services provided by their host IOU or are generally proven in the industry. Examples of this include CCAs like MCE, which has exercised its right to apply for energy efficiency (EE) program funding from the CPUC.[6] To do so, it must file various plans explicitly detailing what they intend to do in the EE program along with reporting requirements and protocols to verify that the energy savings that is projected will occur. If approved, the CCA receives money that is collected in IOU rates through the Public Purpose Program (PPP) rate element. Another example of this second phase of CCA evolution is offering rooftop solar programs and feed-in-

[6] Note that customers taking commodity service from a CCA are still eligible to participate in EE programs administered by their host IOU, regardless of whether or not the CCA is administering their own PPP-funded EE programs or not.

tariffs (FiTs) for local renewable generation projects that connect "in front of" the customer meter. A third example is installing additional electric vehicle (EV) charging stations and encouraging EV purchasing and leasing.

The third phase in evolution observed with California CCAs is the movement into innovative and less common power-related programs and services. These are programs that are not common in California or elsewhere and may be more in the "demonstration" part of the program/technology lifecycle. Examples of these programs include Sonoma Clean Power's efforts to electrify the areas that were destroyed in wildfires (i.e., work with PG&E to perhaps not provide gas service to these areas) or the microgrid programs being pursued by Redwood Coast Energy Authority and Monterey Bay Community Power (now known as Central Coast Community Energy).

Table 2, below, shows a range of the programs being pursued by some California CCAs.

These non-commodity program offerings are becoming the focus of CCAs in the state. At the Business of Local Energy Symposium, a large CCA-oriented conference held in June 2019 in Irvine, CA, the speakers, panels, and presentations overwhelmingly focused on innovation that CCAs can do and are doing.[7] None addressed power procurement or cost competitiveness.

[7] https://theclimatecenter.org/the-business-of-local-energy-symposium-2019-presentations/

Table 2. Sample California CCA Program Offerings[8]

CALCCA ADVANCING LOCAL ENERGY CHOICE	Apple Valley Choice Energy	Central Coast Community Energy	Clean Power Alliance	CleanPowerSF	East Bay Community Energy	King City Community Power	Lancaster Choice Energy	MCE	Peninsula Clean Energy	Pioneer	PRIME	Rancho Mirage Energy Authority	Redwood Coast Energy Authority	San Jacinto Power	San Jose Clean Energy	Silicon Valley Clean Energy	Solana Energy Alliance	Sonoma Clean Power	Valley Clean Energy
Budget Billing				In dev.			✓												
Battery Storage Rate				In dev.	✓ (pilot)			✓								✓ (Same as PG&E)		In dev.	
Battery Storage Incentives								✓								In dev.		✓	
Demand Response		✓	✓	✓				In dev.	In dev.							In dev.		✓	✓
EV Rate		✓	✓	✓	✓ (Same as PG&E)		✓	✓	✓	✓ (Same as PG&E)	✓		✓		✓ (Same as PG&E)	✓ (Same as PG&E)	✓	✓	✓ (Same as PG&E)
EV Bus Program		✓		✓			✓		✓									✓	
EV Incentives (vehicles and/or charging)		✓					✓	✓	✓				✓		In dev.	✓		✓	In dev.
EV Load Shifting								✓								✓ (pilot)		✓	
Energy Efficiency				In dev.			✓	✓		In dev.			✓			In dev.		✓	✓
Energy Efficiency Data Sharing					✓														
Feed-In Tariff		In dev.		In dev.				✓					✓					✓	
Building Electrification		✓			In dev.			✓	In dev.				✓			✓		✓	In dev.
Low-Income & Multifamily EE		✓						✓	In dev.		✓		✓						
Solar Incentives												✓	✓						
On-Bill Repayment				In dev.				✓										In dev.	
Education, Outreach, and/or Innovation Grants			✓		✓				✓	In dev.						✓		✓	
Low-Income Solar Incentives		✓	In dev.	✓	✓	✓		✓	In dev.		✓								
Customer Load Shifting			✓	✓				✓								In dev.		✓	
Microgrid Development		✓					✓			In dev.			✓						
Citizen Sourcing			✓				✓						✓						
Energy Education in Local Schools				In dev.					✓						✓			✓	
Dividend Program		✓																	✓
Solar Referral Service			✓													✓			
Solar+Storage Offerings			In dev.		✓			✓	✓		In dev.		✓			✓		✓	
Advancing Reach Codes		✓			✓				✓							✓		✓	
Advanced Energy Rebuild								✓										✓	
TOU Rates				✓	✓ (Same as PG&E)		✓	✓		✓ (Same as PG&E)			✓		✓ (Same as PG&E)	✓ (Same as PG&E)	✓	✓ (Same as PG&E)	✓ (Same as PG&E)
Customer C&I Clean Power Offerings																✓			
Workforce Education & Training								✓								✓		✓	
Emissions Inventory Support for Member Agencies		✓														✓			
Property Assessed Clean Energy (PACE)										✓									

[8] https://cal-cca.org/cca-programs/

Chapter 2. MRW Financial Study Methodology and Key Inputs

This chapter summarizes the key inputs and methodologies used to evaluate the cost-effectiveness and cost-competitiveness of OCPA relative to SCE under different scenarios. It considers the regulatory requirements that OCPA would need to meet (e.g., compliance with renewable portfolio standard (RPS) requirements), the resources that the City has available or could obtain to meet these requirements, and the SCE rates against which the CCA would compete. It also describes the pro forma analysis methodology that is used to evaluate the financial feasibility of the CCA.

The load and rate forecasts go out 10 years— from 2022, the earliest a CCA could be formed, through 2031. While all forecasting contains uncertainty, the years beyond 2030 are particularly uncertain and should be seen as broadly indicative and not predictive.

OCPA and Huntington Beach Loads and CCA Load Forecasts

A fundamental operational role of a CCA is to forecast customer electricity needs in the short, medium, and long terms. Power procurement and day-to-day decision-making rely heavily on short-term forecasts of consumer demand for power, while procurement planning requires forecasts of longer-term loads. Procurement must also account for the risks associated with demand forecasting and develop appropriate risk mitigation strategies. Though it is not possible for any entity to predict with absolute certainty future energy demand; logical, data-driven, industry-standard methodologies for load forecasting will be used to provide the foundation of future procurement.

Because OCPA is still hypothetical and has yet to serve any customers, the CCA's estimated load to be served is based on historical consumption data from SCE. Of course, if the CCA moves forward the load forecast will be continually updated and refined to reflect ongoing economic development in the Huntington Beach and the other four cities and changes in load from energy efficiency and distributed generation.

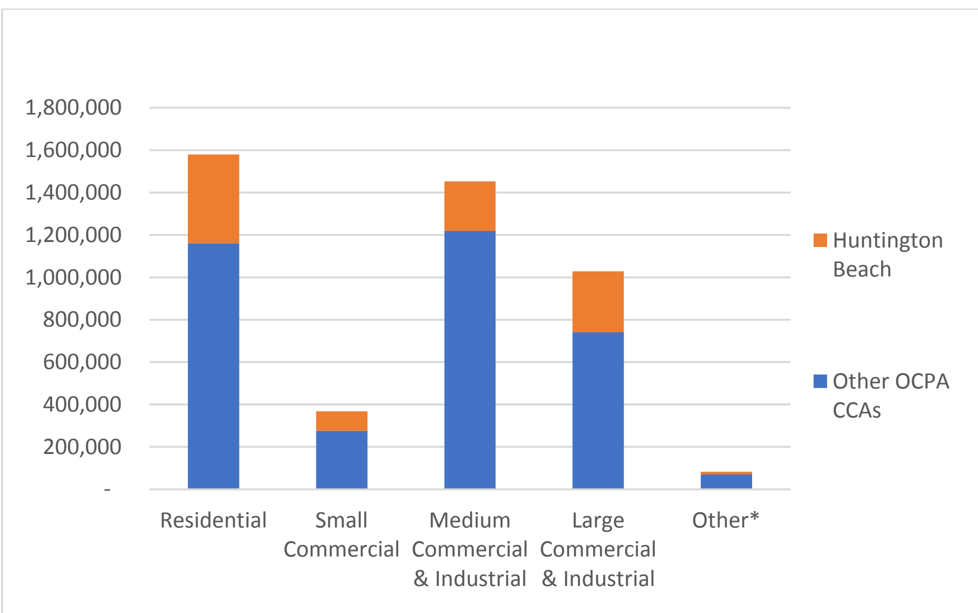
As shown in Table 3, OCPA has over 330,000 customer accounts compared to the 86,000 customers in Huntington Beach. OCPA's total annual electric load in 2019 is about 4,500 GWh, with 1000 GWh of that load demand coming from Huntington Beach. As shown in both the table and in Figure 3, Huntington Beach has a higher percentage of residential load compared to the other OCPA cities and a lower percentage coming from small commercial and the "other" category (street and traffic lights, pumping, agriculture).

Table 3. Potential OCPA Customers and Associated Load for 2019

	OCPA		Huntington Beach		H.B. Percent of OCPA	
	Customers	Annual Load (MWh)	Customers	Annual Load (MWh)	Customers	Annual Load
Residential	288,041	418,684	75,940	1,579,280	26%	27%
Small Commercial[9]	32,138	92,635	8,732	368,188	27%	25%
Medium Commercial	6,216	233,810	1,145	1,452,384	18%	16%
Large Commercial & Industrial	191	287,178	26	1,028,396	14%	28%
Other*	4,032	12,833	539	82,769	13%	16%
Total	330,617	1,045,139	86,382	4,511,017	26%	23%

*e.g., streetlights, traffic control, agriculture/pumping.

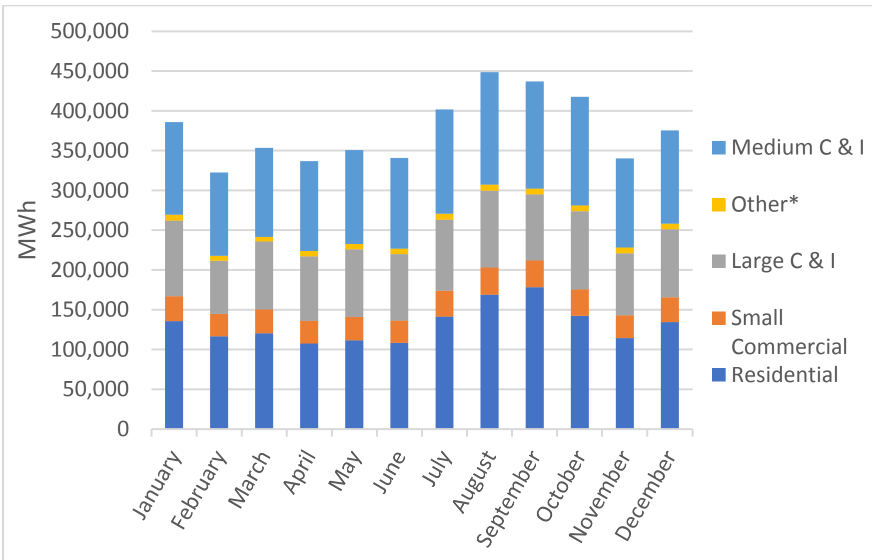
Figure 3. Huntington Beach Load Distribution 2019



[9] In this study, Schedule GS-1 is "Small Commercial" and Schedules GS-2 and GS-3 are classified as "Medium Commercial."

Figure 4, below shows the potential monthly load for the OCPA. The highest load months are in the summer, while the lowest are in November and the spring. This is attributable to the cities in OCPA using air conditioning in the summer and heating in the winter. There is a 39% difference between the highest load month and lowest load month. This means OCPA will need to acquire less "resource adequacy" capacity to cover their summer peaking loads as compared to other CCAs. [10]

Figure 4. OCPA Load (Monthly, 2019)

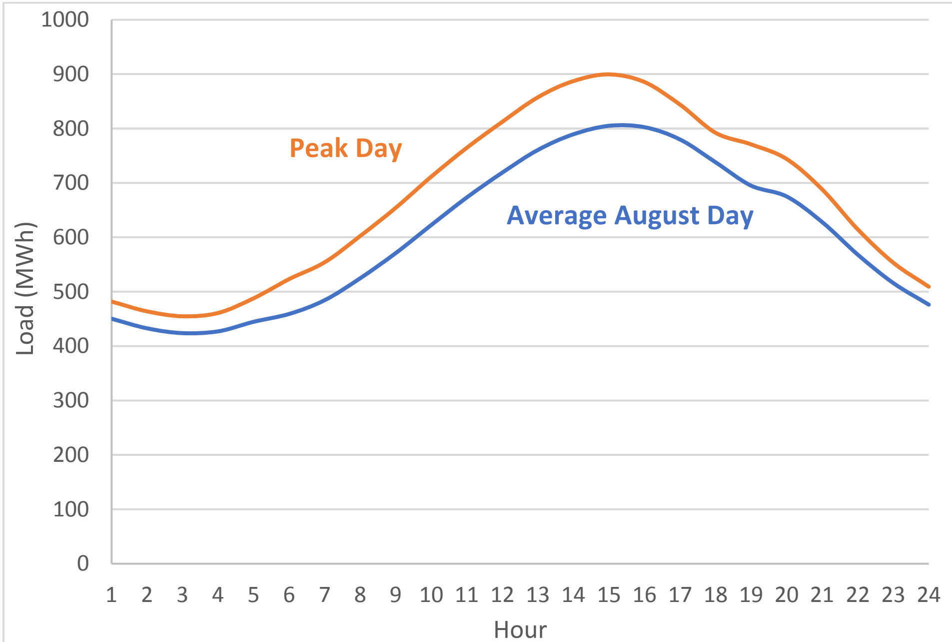


To be able to project the cost of buying power for the CCA, one must not only know how much must be purchased, but when. This is accomplished using load profiles: the breakdown of the total load into hourly consumption values. SCE provided an hourly load profile for different rate classes and monthly data for each city.

Figure 5 below illustrates the 24-hour load curve for OCPA. It compares the average day in the highest load month of August with the peak day of the year, September 4th. The peak hour was 3 pm on September 4th with a load of nearly 900 MWh. This is the maximum capacity needed for the CCA and is the basis for the OCPA's resource adequacy requirement in September. Compare this to the peak on an average August day where the peak hour was also 3 pm and the peak load was 805 MWh. The significant difference between the two maximum loads highlights the load volatility in the CCA. It is also interesting that the load peaks so early in the day, an afternoon peak will pair well with solar resources.

[10] The ratio of the usage in the highest-load month to the lowest-load month for OCPA is 1.4; for the City of Riverside, a municipal utility, the ratio of the highest-load month to the lowest-load month is 1.7. (City of Riverside Public Utilities, 2018 Integrated Resource Plan, September 26, 2018. page 2-2.)

Figure 5. OCPA Load Shape Peak Day Vs Peak Month



Forecasting

The CCA's base load forecast through 2031 reflects the annual average growth rate from the California Energy Commission's most recent electricity demand forecast for SCE's planning area.

CCA Power Supplies

The cost to provide power is by far the largest expenditure a CCA makes. A CCA the size of OCPA should expect to spend over $200 million per year for wholesale power. The OCPA power supply plan will be guided by legislative requirements, regulatory mandates, and CCA policies, as well as future market dynamics.

Regulatory Procurement Requirements

California places a number of important power-procurement requirements on all "load serving entities" (LSEs) in California (e.g., utilities like SCE and CCAs). These requirements apply to all LSEs and thus can limit the options that a CCA can pursue to lower costs or implement lower-GHG emitting power portfolios.

Renewable Energy. One of these requirements is the renewable portfolio standard (RPS). This requirement has been in place since 2002 with passage of Senate Bill (SB) 1078, which set a requirement that 20% of retail electricity sales be served by renewable resources by 2017. Since then, the RPS requirement has been accelerated and expanded by subsequent legislation, most recently by SB 100 passed in 2018. SB 100 requires all LSEs to procure 50% of their power from renewable resources by 2026 and 60% by 2030.[11] SB 100 also sets a state-wide policy goal of having 100% of the electric power met by renewable or carbon-free resources (e.g., large hydroelectric dams) by 2045.

This means that SCE is subject to the same renewable resource mandates under SB 100 as OCPA will be. Unless OCPA makes an explicit decision to exceed the state requirements, it would be offering no incremental renewable “benefits” to the City. This is why many existing CCAs’ goals are often to accelerate the implementation of green power above and beyond the state’s mandates and goals.

Energy Storage. Assembly Bill (AB) 251 requires LSEs to procure energy storage capacity. The storage mandate was implemented by the California Public Utility Commission (CPUC) through a requirement that CCAs procure energy storage equal to one percent of their forecasted 2020 peak load. CCAs must demonstrate progress towards meeting this target in biennial advice letter filings and must have the energy storage capacity in place by 2024. Some energy storage technologies, especially lithium-ion batteries, have fallen steeply in cost in recent years, though they are still relatively expensive compared to supply resources and demand response. Battery costs are expected to continue to fall, suggesting there is a benefit to deferring procurement until required by the mandate.

Resource Adequacy. Since 2006, all LSEs, including CCAs, that are participants in the CAISO balancing area and under the jurisdiction of the CPUC are responsible for complying with Resource Adequacy (RA) obligations required under Assembly Bill 380 (codified as Section 380 of the Public Utilities Code and implemented by CPUC rulemaking). There are three components to the RA compliance program:

1) **System** capacity requirements to meet expected peak loads in the entire CAISO balancing area.
2) **Local** capacity requirements to meet contingency needs in locally constrained areas; and
3) **Flexible** capacity requirements to meet the largest continuous three-hour ramp in each month.

Specifically, to meet the System RA requirement, load serving entities must contract for 115% of their projected monthly peak demand as determined by the CPUC in consultation with the California Energy Commission (CEC) load forecasts. The peak demand forecasts are based on a 1-in-2 (average) weather year. Year-ahead filings must show that the LSE has contracted for 90% of the projected System RA requirement in summer months (May-September). The forecasts must be updated on a month-ahead basis and show that 100% of the requirement has been contracted.

[11] In practice, the utility code establishes multi-year compliance periods ending in 2020, 2024, 2027 and 2030, with the average renewable energy supply as a percentage of retail sales for each compliance period required to be 33%, 44% 52% and 60%, respectively.

The Local RA requirement must be met by LSEs with customers in 10 local reliability areas identified by the CAISO. The Local RA requirement is based on the CAISO's assessment of the generation needed in the local area. Beginning with the 2020 compliance year,[12] the Local RA requirements are set three years ahead and updated each year.[13]

On June 11, 2020, the CPUC adopted a framework (D. 20-06-002) that designated a central buyer for the procurement of multi-year Local RA in the SCE and SCE distribution areas, beginning in 2021. Currently, both SCE and SCE serve as central procurement entities for their distribution service areas and have begun procuring Local RA for the 2023 compliance year. Therefore, SCE would act as the Local RA procurer for any future CCA that served Huntington Beach.

The CAISO also determines the required Flexible RA needs operating criteria. Currently there are three flexible capacity categories with varying must-offer obligations, energy limits and number of starts, with associated requirements for how much of each category may be used to meet the LSE's obligation. LSEs must demonstrate the purchase of 90% of their flexible RA requirement in their annual RA filing, and 100% of the requirement in their monthly RA filings.[14]

There is a bilateral market for RA capacity, with standardized products for each type of RA capacity.

Integrated Resource Planning (IRP). In addition to its role as the authority for implementing the state's RA program, the CPUC also has an active rulemaking to "Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements" (R. 16-02-007). This program requires each California LSE to file a procurement plan that demonstrates that it is contributing its pro rata share to meeting the State's GHG reduction goals while maintaining sufficient generating and storage capacity to maintain a reliable power grid.

On November 11, 2019, the CPUC issue a decision (D.19-11-016) that addressed the potential for system resource adequacy shortages in SCE's area due to the impending retirement of 3,750 MW of once-through cooled (OTC) generation by December 31, 2020 as well as the risk of additional non-OTC retirements. The decision recommended that the State Water Resources Control Board extend OTC compliance deadlines for the impacted power plants and required additional procurement of 3,300 MW of system-level RA capacity by all LSEs serving load

[12] The "compliance year" is the year in which the RA resources are used to meet the LSE's RA requirements for that year. For example, an LSE must demonstrate in 2019 that it has adequate RA capacity under contract for the 2020 RA compliance year.

[13] Note that Local RA capacity is a substitute for System RA capacity. However, the converse is not always true, meaning that System RA capacity might not help an LSE meet its Local RA requirements.

[14] Flexible RA can substitute for System RA and possibly for Local RA but the converse is not always true: System and Local RA resources might not help an LSE meet its Flexible RA obligations.

within the CAISO balancing area. Because this analysis assumes that OCPA begins service in 2023, it will not need to take any special action to comply with these directives.

Power Supply Portfolio and Cost Assumptions

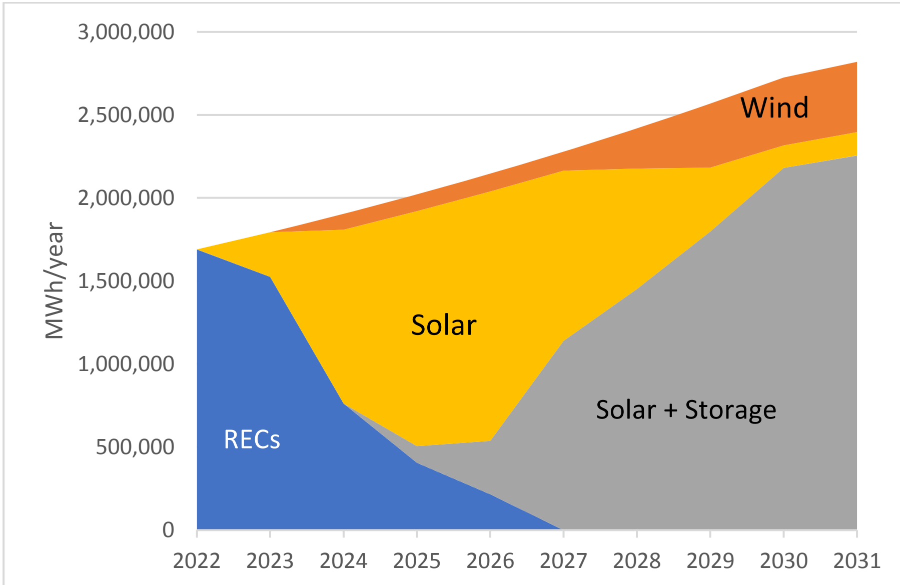
Operating within the regulatory framework described above, MRW has developed sample electric supply portfolios for use in evaluating the economics of CCA formation in Huntington Beach. These sample portfolios are a proxy for a working portfolio that would be developed using a more rigorous assessment of costs and risk attributes developed as part of an implementation plan and ultimately through direct engagement with market participants via a request for proposals process. With RPS requirements increasing to 62% of load during the period of analysis, renewable resource assumptions are the primary driver of portfolio costs. After accounting for the hourly CCA load shape and the generation profile of resources in the renewable energy portfolio, the residual net short is assumed to be met with market purchases at hourly market prices forecast by S&P Global. Likewise, resource adequacy requirements are estimated based on peak loads and after accounting for net qualifying capacity from renewable resources. The remaining capacity need is assumed to be purchased at a forecasted market price as described below.

Renewable

The cost of renewable energy from solar photovoltaic (PV) facilities has steadily fallen since the establishment of the California RPS mandate in 2002. Looking forward, solar PV prices are expected to continue to decline, although perhaps at a slower rate as the technology matures and if import tariffs continue to be applied. At the same time, the incremental value of solar energy is decreasing as more and more solar resources are added to the electrical system, leading at times to conditions where solar energy must be curtailed to avoid over generation. Thus, there are advantages to a diversified supply portfolio including wind, geothermal and biomass, as well as energy storage.

Figure 6 below shows the assumed mix of renewable resources in Supply Scenario 1: meeting but not exceeding the State's renewable portfolio requirement, e.g., 50% by the end of 2026, with incremental hydroelectric power so that the CCA has the same net GHG output as SCE. In the first few years, the RPS requirement will be met using contracts for unspecified in-state renewable generation, with some generation from power purchase agreements (PPAs) with existing solar resources. Over time, the reliance on unspecified in-state renewables decreases and is replaced with PPAs with specific wind resources as well as PPAs with solar bundled with storage facilities. This reflects a reasonable balance of renewable resources: wind and solar are generally complementary in California—that is, when solar output is high, wind output is low.

Figure 6. Renewable Power Generation by Source



Assumed renewable power prices are shown in Figure 10. The 2022 prices are consistent with current reported renewable contract prices from other load-serving entities, including California CCAs and municipal utilities.[15]

With the rate of utility-scale solar PV cost declines flattening in recent years, we assume a slight increase in solar PV costs over the forecast period. Based on data provided by Lawrence Berkeley Laboratory, solar combined with battery storage is assumed to be available at a $5/MWh premium relative to solar-only projects and to follow the same trends as utility-scale solar. For local solar and solar plus storage, we assume projects are likely to be commercial scale (i.e., large rooftop), so we relied on NREL's U.S. Solar Photovoltaic System Cost Benchmark and Cost-Reduction Roadmap for Residential Solar Photovoltaics Report for Commercial PV, which show declines from 2020 costs through 2030.[16]

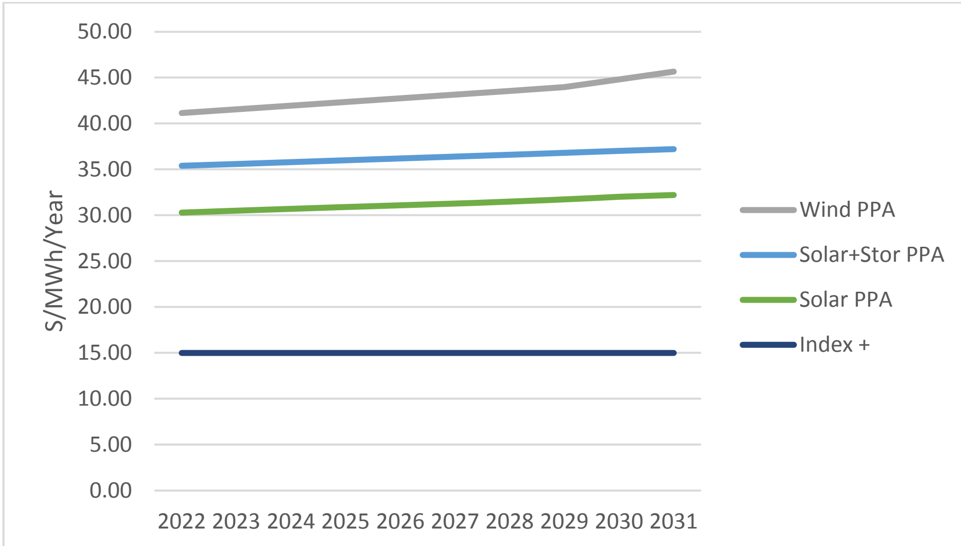
For wind prices we relied on the DOE's Wind Vision report to establish a forecasted price for 2020 through 2040 and continued the price trend for subsequent years.[17]

"Index+" refers to the cost of a Bundled Renewable Energy Credit ("Bucket 1" REC) whose associated energy is priced at the CAISO hourly market price. The REC value is assumed to be $15/MWh, remaining level in nominal dollars.

Alternative renewable energy costs are explored in the sensitivity scenarios.

[15] https://emp.lbl.gov/sites/default/files/2020_utility-scale_solar_data_update.pdf
[16] https://www.energy.gov/eere/solar/sunshot-2030
[17] https://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf, Figure 3-12.

Figure 7. Projected Average Renewable Power Costs

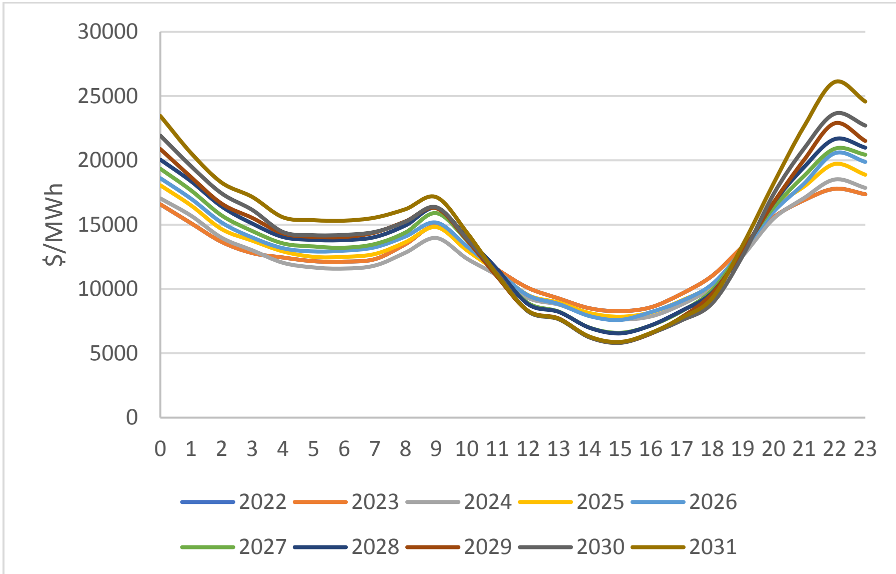


Wholesale Power Costs

The residual net load after accounting for renewable energy supplies is assumed to be supplied from wholesale market purchases, either from the day-ahead market operated by the CAISO or through bilateral contracts with similar market pricing. To forecast market prices, we used S&P Global Market Intelligence's 2020 3rd Quarter Forecast for CAISO SP15 Hourly Energy Prices. S&P Global provides 20-year forward-looking wholesale electricity and capacity price projections based on forward market prices and fundamentals-based modeling relying on data from regulatory filings, planning guidelines, coal plant retirements, firm construction plans, and additions of renewable energy.

Figure 8 shows the average hourly price comparison of the 10-year price forecast. In real terms, there is little difference in the peak period energy prices across years. However, as increased renewables are built over the 10-year period, the mid-day prices during high solar hours are anticipated to get more depressed and evening prices are forecast to rise. In California, electricity prices are often set by gas-fired resources operating on the margin. However, as increasing supplies of renewable energy are added to the system, there are periods where prices are being set by zero or even negative marginal cost resources. As a result, market prices have been trending downward, especially during seasons and periods of the day when loads are low and solar output is high. The modeling provided by S&P shows a continuation of the trend, with prices falling during the middle of the day and increasing in the morning and evening when gas-fired resources are needed to meet peak loads outside of the solar supply period. Figure 8 presents the average hourly shape of forecasted SP15 CASIO market prices over a 10-year period. Price data for individual months or days demonstrate even greater variation across the hours of a day.

Figure 8. Assumed Market Prices (2022-2031)



Capacity Costs

As noted above, CCAs are also responsible for complying with Resource Adequacy (RA) obligations. These products are typically contracted on a short-term basis (e.g., year-ahead). There has historically been an excess supply of both system and flexible capacity in the market, leading to depressed prices for these products. This changed dramatically in 2019, when RA prices doubled. MRW predicts that the system RA price will continue to fluctuate between $6.00/MWh to $9.00/MWh, but that the flexible RA price will remain stable.

Traditionally, CCAs have also bought local RA, but as of 2023, CCAs in SCE's territory will no longer be responsible for acquiring local RA. SCE will purchase and allocate local RA to CCAs. The specifics of this new process are still being worked out in regulatory filings and future analysis will be needed to see how this new model will affect costs.

Pro Forma Elements and CCA Costs of Service

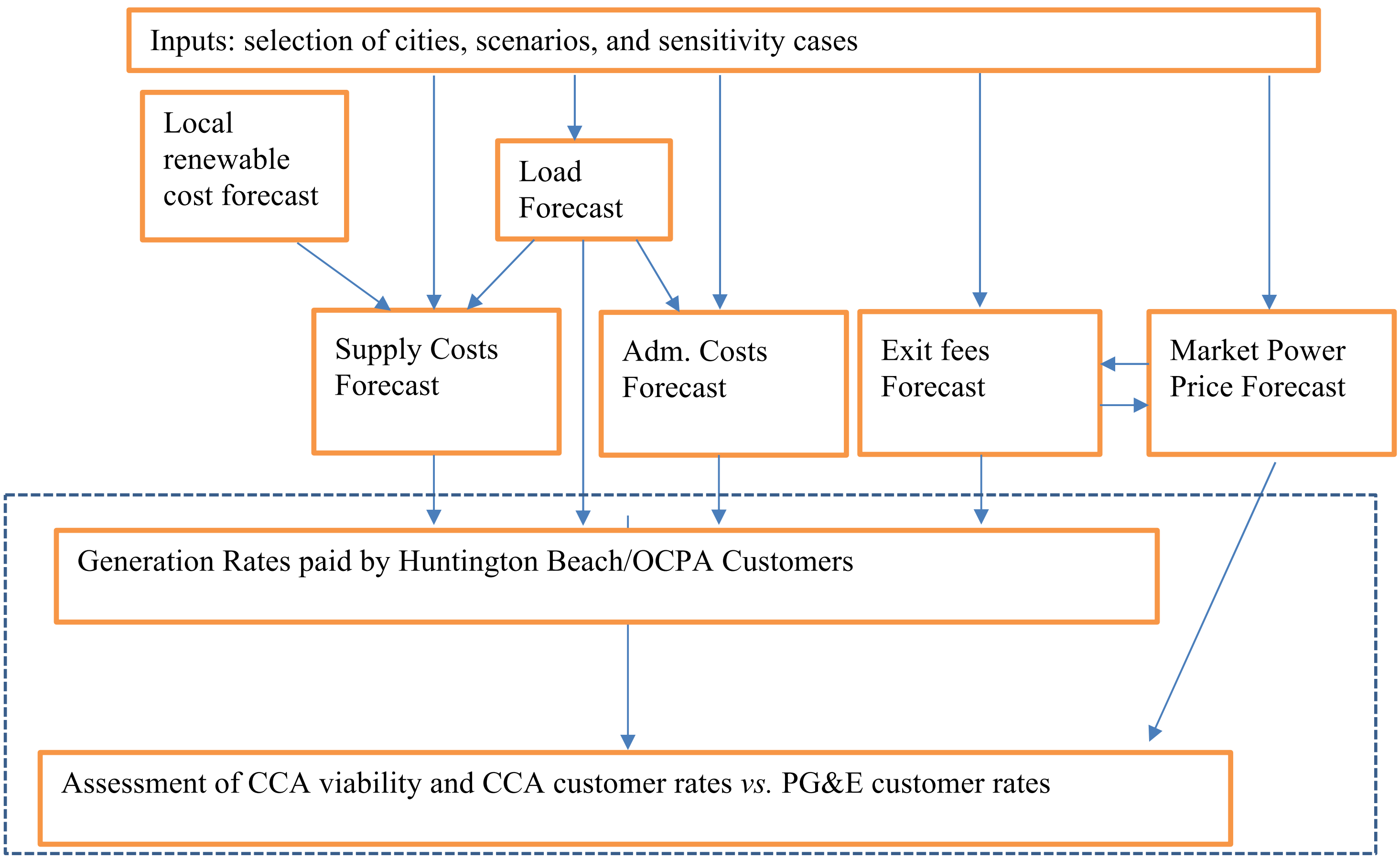
This section outlines the main elements of the pro forma analysis, the assumptions underlying the elements and the output results. The analysis also includes a comparison between the generation-related costs that would be paid by OCPA customers and the generation-related costs that would be paid by SCE bundled service customers. Costs paid by CCA customers include all CCA-related costs (i.e., supply portfolio costs and administrative and general costs) and exit fee payments that CCA customers will be required to make to SCE.

Pro Forma Elements

Figure 9 provides a schematic of the pro forma analysis, outlining the input elements of the analysis and the output results.

As discussed in previous sections, supply portfolio costs are informed and affected by CCA loads, by the requirements the CCA will need to meet (or will choose to meet) such as with respect to renewable procurement, and by CCA participation levels. Administrative and general costs are discussed further below.

Figure 9. Pro forma Analysis



Startup Costs

Startup costs are the costs OCPA will incur before operations begin. Table 4 shows the estimated CCA startup costs. They are based on the experience of existing CCAs as well as from other CCA technical and feasibility assessments. If Huntington Beach were to move forward with OCPA, these values would be refined based on more detailed projections.

Table 4. Estimated Start-Up and Annual Ongoing Costs

Item	Cost	One-time or Ongoing?
Professional Services/Consulting	$150,000	Ongoing at reduced level
Staffing	$2,100,000	Ongoing, lower initially
Administrative and General costs	$250,000	Ongoing at reduced level
SCE Fees	$10,000	One-time
CAISO deposit	$500,000	One-time
Power contracting, portfolio and rate design, scheduling	$350,000	Ongoing, lower initially
Integrated Resource Plan/Long-Term Procurement	$150,000	Ongoing, lower initially
Marketing strategy and brand development	$75,000	Ongoing at reduced level
Website	$20,000	Ongoing at reduced level
PR/Advertising	$60,000	Ongoing at reduced level
Customer Notifications	$260,000	One-time
Community Sponsorships, etc.	$5,000	Ongoing, lower initially
General Counsel Services	$120,000	Ongoing, lower initially
Legal review of power supply and other vendor contracts	$75,000	Ongoing at reduced level
Cal-CCA Membership	$200,000	Ongoing, lower initially
Regulatory Monitoring, Reporting and Compliance	$100,000	Ongoing, lower initially
Total:	$4,400,000	
Working Capital (3 months cash flow at full service)	~$60,000,000	One-time; maximum line of credit amount
Total:	$64 million	

Typically, the city forming a CCA would directly pay for the initial start-up costs, such as the technical study. In this situation, the City of Irvine has offered to supply the collateral for a bank loan to finance the initial start-up costs. Once the CCA is formed by City Council action, the CCA would issue an RFP for banking services. These would set up a short-term loan or line of credit to pay back the city its CCA expenditures and fund ongoing start-up costs until the CCA is operational. At that point, the short-term loans could be rolled into a longer-term loan that would also include working capital.

Working capital reflects the fact that a business will have bills to pay prior to receiving payment from its customers. This amount would cover the timing lag between when invoices for power purchases (and other account payables) must be remitted and when income is received from the customers. Per industry standard, total working capital is set to equal three months of CCA revenue, or approximately $64 million when the OCPA is fully operational (i.e., serving all potential customers.)[18] Initially, the working capital is provided by a bank on credit to the CCA. Typical power purchase contracts require payment for the prior month's purchases by the 20th of the current month. Customers' payments are typically received 60 to 90 days from when the power is delivered.

These startup costs are assumed to be financed over 5 years at 5% interest.[19] Historically, CCAs have paid down their start-up loans much more quickly.

Reserves

CCAs to date have all committed to setting aside revenues into a reserve fund to account for times in the short-term when its costs may not allow it charge rates that are competitive to SCE. For this study, we assume that the CCA will endeavor to set aside revenues until a reserve fund reaches an amount equal to 50% of its annual revenue (e.g., 50% of $324 million = a reserve fund goal of $165 million). After the reserve target is met, it is held at the target level or drawn upon so that the desired CCA rate is achieved. If the reserve is drawn upon, the rate reserve is replenished in the next year in which headroom is available.

Administrative and General Cost Inputs

Administrative and general costs cover the everyday operations of the CCA, including costs for billing, data management, customer service, employee salaries, contractor payments, and fees paid to SCE. Table 5, below summarizes the assumed ongoing administrative and general costs. These costs are assumed to trend with inflation.

[18] CCAs frequently "phase-in" their service, initially offering service to a smaller subset of customers and then expanding service to the remaining customers over the following months or years.

[19] 5% is currently equal to the prime rate plus 175 basis points.

Table 5. Ongoing Administrative and General Costs

	2021	2022	2023	2024
SCE Fees, $/cust./month	$0.13	$0.13	$0.14	$0.14
Data Management Fees $/cust./mo.		$1.00	$1.00	$1.00
Administration – Labor[20]	$330,000	$1,300,000	$2,100,000	$2,200,000
Administration- Non-Labor	$25,000	$260,000	$150,000	$160,000
Outreach-communications	$80,000	$160,000	$67,000	$68,000
Professional Services	$150,000	$330,000	$560,000	$580,000
Data Management Fees	$0	$2,500,000	$3,900,000	$3,900,000
SCE Metering and Billing Fees	$0	$500,000	$510,000	$530,000
Total	$590,000	$3,300,000	$7,300,000	$7,400,000

SCE Rate and PCIA Forecasts

SCE Generation Rates

Forecasts of SCE's generation rates and exit fees are necessary to compare the projected rates that customers would pay as OCPA customers to the projected rates and fees they would pay as bundled SCE customers.

To ensure a consistent and reliable financial analysis, a 10-year bottoms-up forecast of SCE rates was developed using market prices that are consistent with those used in the forecast of the OCPA's supply costs. The forecasted costs include the cost of SCE's existing resource portfolio, adding in market purchases only when necessary to meet projected demand.

To develop this forecast, the key cost drivers of each of SCE's generation rate components were examined, separately evaluating costs for renewable and non-renewable energy purchases, for SCE-owned generation facilities, and for capacity purchases. The study assumed that near-term changes to SCE's generation portfolio would be driven primarily by modest increases in underlying gas market prices. In 2028-2030, consistent with the OCPA forecast, the SCE must pay higher prices for incremental capacity and resource adequacy, reflecting the tightening of the capacity market at that time.

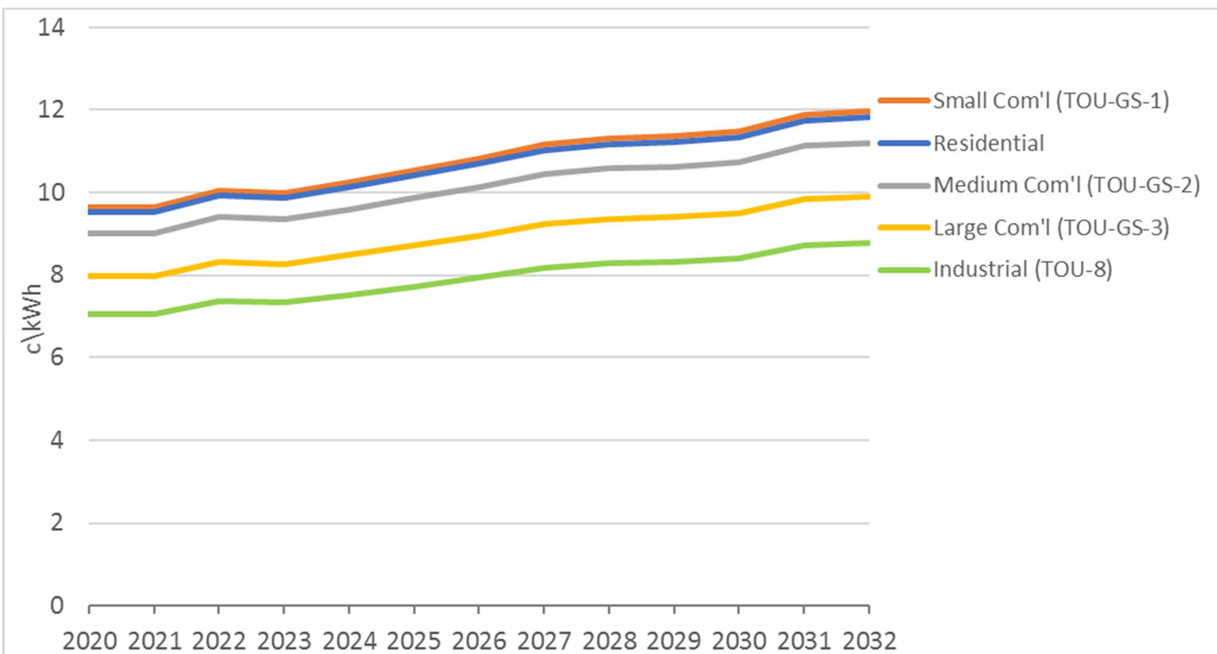
[20] See page 60 for staffing estimate details.

The forecast further assumes that SCE is compliant with the renewable and carbon-free requirements ordered in Senate Bill 100: a minimum of 60% renewable content in 2030 and a trajectory that would, when extrapolated, result in carbon-free power in 2045. In fact, given the current SCE renewable portfolio and the loss of load from the OCPA, SCE would need minimal if any new renewables to meet the 2030 goal.

The forecast for SCE's generation resources is based on publicly available data and forecasts. We relied on the market price forecast produced by S&P Global to estimate the cost of market purchases. However, since SCE protects data that would reveal its detailed net short position, we were unable to perform the hourly analysis completed for Huntington Beach and instead relied on average market prices to develop estimates of the cost of SCE market purchases.

Over the 10-year period, the study forecasts that SCE's generation rates will escalate by an average of 3% per year. This forecast is show in Figure 10, below.

Figure 10. Forecast SCE Average Generation Rates



PCIA

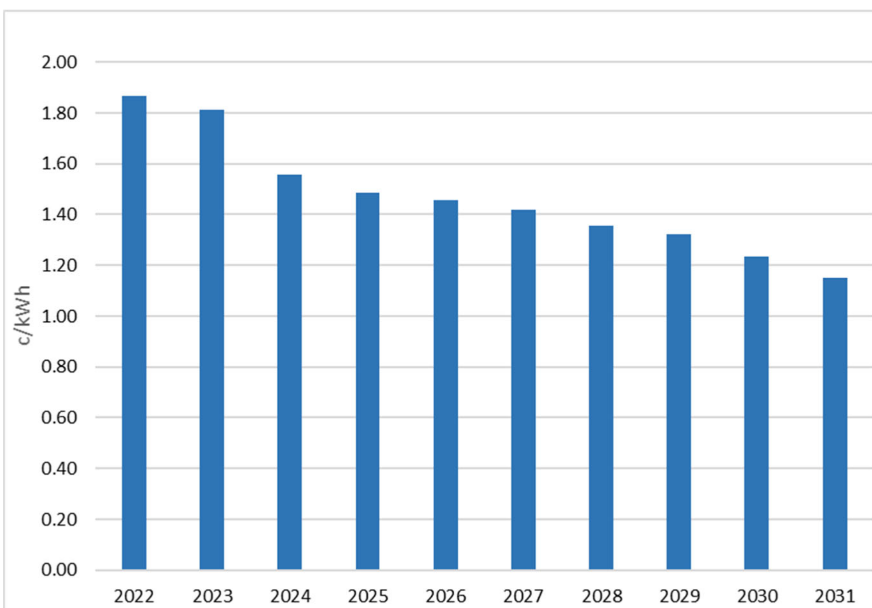
The Power Charge Indifference Adjustment (PCIA) is a fee charged by SCE intended to prevent customers that remain with SCE bundled service from paying for energy generation procured on behalf of customers that have since switched to CCA service. More specifically, it pays for the above-market costs of SCE generation resources that were acquired, or which SCE committed to acquire, prior to the customer's departure to CCA. The total cost of these resources is compared to a market-based price benchmark to calculate the "stranded costs" associated with these resources, and CCA customers are charged what is determined to be their fair share of the stranded costs through the PCIA. Bundled customers also pay the PCIA, which is embedded into their commodity portion of their total rate.

The PCIA is not paid directly by the CCA, but by the individual customers taking CCA service. Thus, it does not appear explicitly on the CCA's books, however it must be accounted for in any CCA cost analysis. While both CCA customers and customers that choose to remain in SCE bundled service pay this fee, it appears as a separate line item for CCA customers and is embedded in the energy generation costs of SCE bundled customers.

To forecast the PCIA, this study used the formula and approach dictated by the Alternative Proposed Decision of Assigned Commissioner Carla Peterman in Commission Rulemaking 17-06-026, which was approved by the Commission on October 11, 2018. In addition, the market price and SCE portfolio assumptions used in the PCIA calculations are consistent with those used to forecast SCE's generation rates.

This study forecasts the PCIA charge by directly modeling expected changes to PCIA-eligible resources and to the market-based price benchmark. Based on our modelling, we expect the PCIA to remain close to 2¢ per kWh through 2023. After 2023, the PCIA is forecast to decrease markedly to about 1.5¢ per kWh and to continue a steady decline through 2031. The decline is mainly caused by the expiration of many of the costlier renewable power contracts entered into by SCE, which decreases the total stranded costs. MRW's forecast of the PCIA charge through 2031 is shown in Figure 11. As such, it can be anticipated that the savings from lower PCIA rates will result in lower CCA rates over time.

Figure 11. Forecast Average PCIA



Chapter 3. Financial Analysis Results

Costs and benefits are evaluated by comparing total average cost to serve the CCA customer (cents per kWh or dollar per MWh) (including PCIA) to SCE generation rates. The pro forma results for the first 10 years of the OCPA are summarized in this chapter.

Supply Scenario assumes that the OCPA simply complies with the State's requirements concerning renewable power. It starts in 2022 with 37% of its power being met using renewable resources and escalates this faction to 62% by 2031. The non-renewable output is assumed to be met using system power from the CAISO.

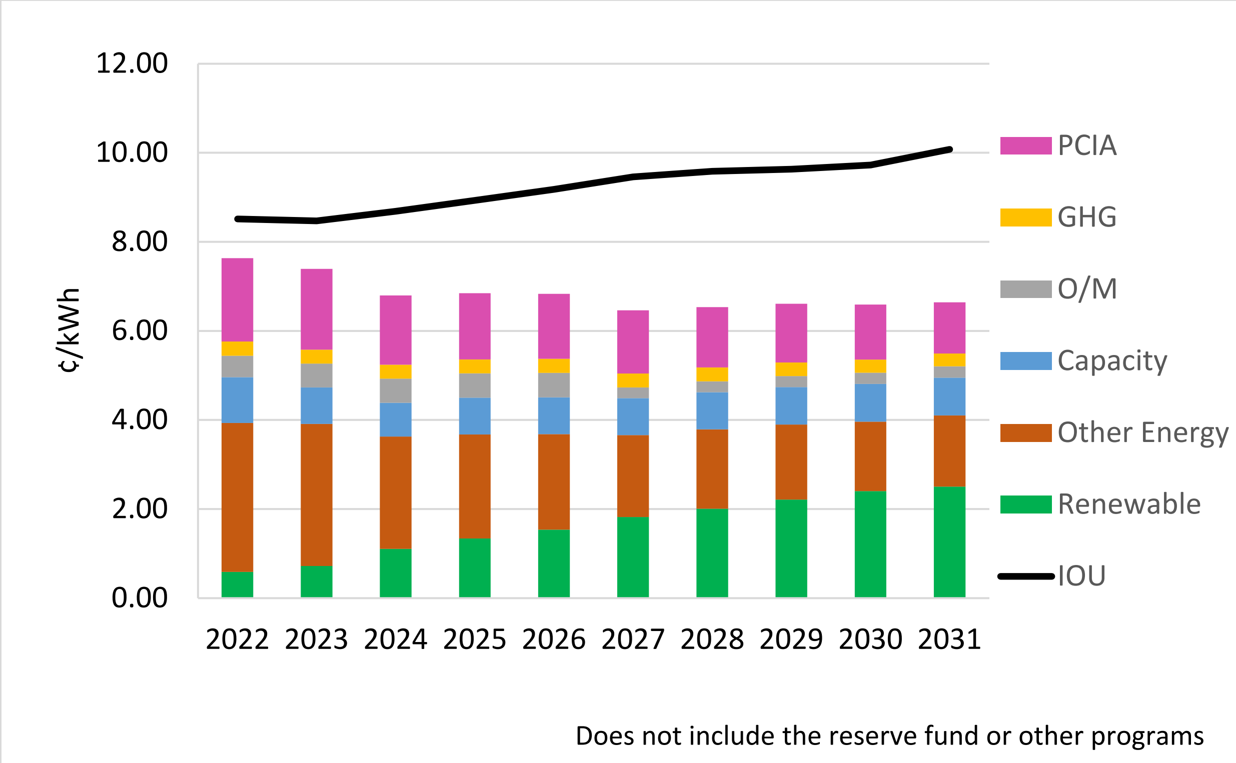
Figure 12 shows the forecast of average MRW-modeled OCPA costs and SCE's generation rates. The bars in the chart show the forecasts of the major cost components of CCA operation, while the single line shows the forecast of SCE's generation rate. When the bars are below the black line, the CCA's average operating costs will be below the SCE generation rate; meaning that it can offer power to customers at a rate lower than or competitive with SCE. As is clearly seen in the figure, the average cost of power provided by the CCA is consistently below the SCE generation rate, although much closer in the first few years of OCPA operation.

The bottom-most green segment represents the cost of renewable power to the CCA. The brown segment is for the costs of non-renewable, wholesale market power. This segment slowly decreases, as renewable power increases. (Because renewables are currently most costly than market power, the analysis assumes OCPA will initially meet the State's minimum renewable power content and ramp up as the requirements increase). The light blue segment is for capacity. That is, the CCA must demonstrate that it has the generating capacity (in megawatts) to ensure that it can serve all its load. The gray segment is for debt service, operations, franchise fees, and uncollectibles. The yellow segment is for carbon cap and trade allowances. Note that for practical purposes, the cost of carbon cap-and-trade allowances would be built into the purchase price of natural gas-fired market resources. However, because it is an important variable on its own, the costs are shown separately.

The top-most pink segment is for the Power Charge Indifference Adjustment (PCIA), a fee paid to SCE to ensure that the operation of the CCA does not strand SCE's remaining bundled customers with costs associated with power purchased on behalf of customers who have shifted to the CCA.

The black line represents SCE's average generation rate. To forecast SCE's generation rates, the comparison model used information regarding SCE's utility-owned generation, power contracts, power market costs, and by closely tracking changes in SCE revenues and costs through its filings in several CPUC proceedings. In particular, it takes the most recent SCE filing of generation rates and applies the known and anticipated changes to the wholesale power market prices and SCE's power purchase contracts.

Figure 12. Average OCPA Cost Projection versus SCE Generation Rate



As shown in Figure 12, the costs of CCA operation are consistently below that of the SCE rate. This difference between the top of the CCA cost columns and the SCE rate line represents the operating "margin." the CCA may do a combination of one or more of three things with this margin:

- **Rate Savings:** The CCA can keep its rates as the cost of operations and allow the margin to flow fully to customers through lower electric rates. (i.e., if the margin is 0.5¢/kWh, then the CCA could offer rates that are 0.5¢/kWh less than SCE while still covering all its costs).
- **Reserves:** The CCA can charge customers the same rate as SCE to retain the margin and build up cash reserves for a rainy day.
- **Programs:** The CCA can eventually use the margin to fund other energy-related services, such as providing incentives for customers to purchase an EV, install energy-efficient home upgrades, install solar PV, etc.

In practice, CCAs use the margin for all three purposes: they set a rate that is marginally lower than SCE's and then use the remaining margin for cash reserves or programs.

In 2022, this "margin" between CCA average cost and SCE rate is about 1¢/kwh, increasing to about 3¢/kwh in 2031. Note that this does not mean that the CCA can or will fully pass on this margin as rate savings to its customers (Table 6). In fact, during the first few years, the CCA's set their rates so that most of the margin between their ongoing costs and SCE's generation rates is set aside for financial reserves and paying down the initial startup loans. Once the financial reserve targets are met and the start-up loans paid off, CCA's typically use a portion of the margin for programs serving their residents and businesses, purchasing greater amounts of renewable power, and providing greater rate discounts that could be offered during the first years. It is up to the CCA Board of Directors to balancing these competing uses (i.e., rate discounts, programs, financial reserves, and greener power).

Table 6. Projected OCPA Margins*

	2022	First 3 years (2022-24)	First 5 years (2022-2026)	2nd 5 years (2027-2031)	10-Years (2022-2031)
¢/kWh (average)	1.0	1.2	1.6	2.9	2.2

*Without rate savings, reserve contributions or program funding

For the CCA, GHG savings is achieved when the average GHG emissions from the set of generation resources used by the CCA is less than the average GHG emissions from SCE. Unless the CCA procured GHG-free power above and beyond California's renewable requirement, SCE's average GHG emission will be less than the CCAs. This result is caused by SCE not only meeting the state-requirement minimum renewable content, but also using other non-renewable but still GHG-free power sources: large hydroelectric dams and nuclear power from the Palo Verde Nuclear Generating Station, of which SCE is a partial owner. The GHG-emitting portfolios for Power Supply Scenario 1 and SCE are shown in Table 7.

Table 7. 2022 CCA (Supply Scenario 1) and 2019 SCE Power Content

	OCPA	SCE[21]
Renewable	37%	35%
Hydro		8%
Nuclear		8%
GHG-Free	37%	51%
Gas		16%
System	63%	33%
Total	100%	100%

[21]SCE Power Mix from SCE's 2019 Power Content Label Template_v2

Sensitivity to Key Inputs

The results shown in the scenarios above reflect expected market conditions and outcomes with variations only in the amount and type of renewable generation. However, it is unlikely that the conditions assumed in these scenarios will occur exactly as assumed. In order to evaluate the robustness of the analysis, the key variables were identified, and analyses conducted with other assumptions for those key variables to "stress test" the assumptions. The four variables with the greatest potential impact on the overall average cost of the CCA were investigated:

(1) Higher Renewable Supply Costs
(2) Higher PCIA
(3) Lower SCE Rates
(4) High Opt-Out

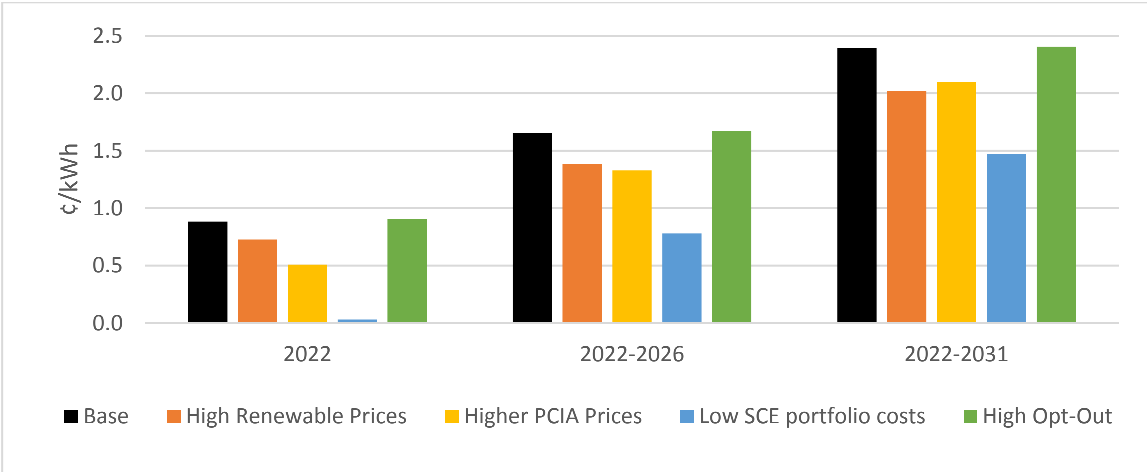
The specific assumptions on the sensitivity scenarios are shown in Table 8.

Table 8. Sensitivity Case Definitions

Sensitivity Case	Definition
Base	Supply Scenario 1
Higher renewable costs	Renewable costs 25% higher than Base
Higher PCIA	PCIA 33% higher than calculated in Base
Lower SCE Rate	SCE rates 10% lower than in Base
Higher Opt-Out	30% opt-out versus 5-10% opt-out in Base

Figure 13 summarizes the CCA margins resulting from the modeling of the sensitivity cases. The figure shows the margin in cents per kilowatt-hour between the SCE rate and the average cost for the CCA to serve its load, including the PCIA, but without any rate discounts or contributions to reserves. When the bar is positive, then the CCA's cost of service is less than SCE's generation rates, which means the CCA can offer a rate discount, contribute to reserves, or fund programs. Consistent with the rest of the analysis, the margins are the smallest during the first years of operation, suggesting that the targeted rate discount may not be achievable during the first few years of OCPA operation.

Figure 13. Sensitivity Results



Rate Savings Currently Offered by CCAs

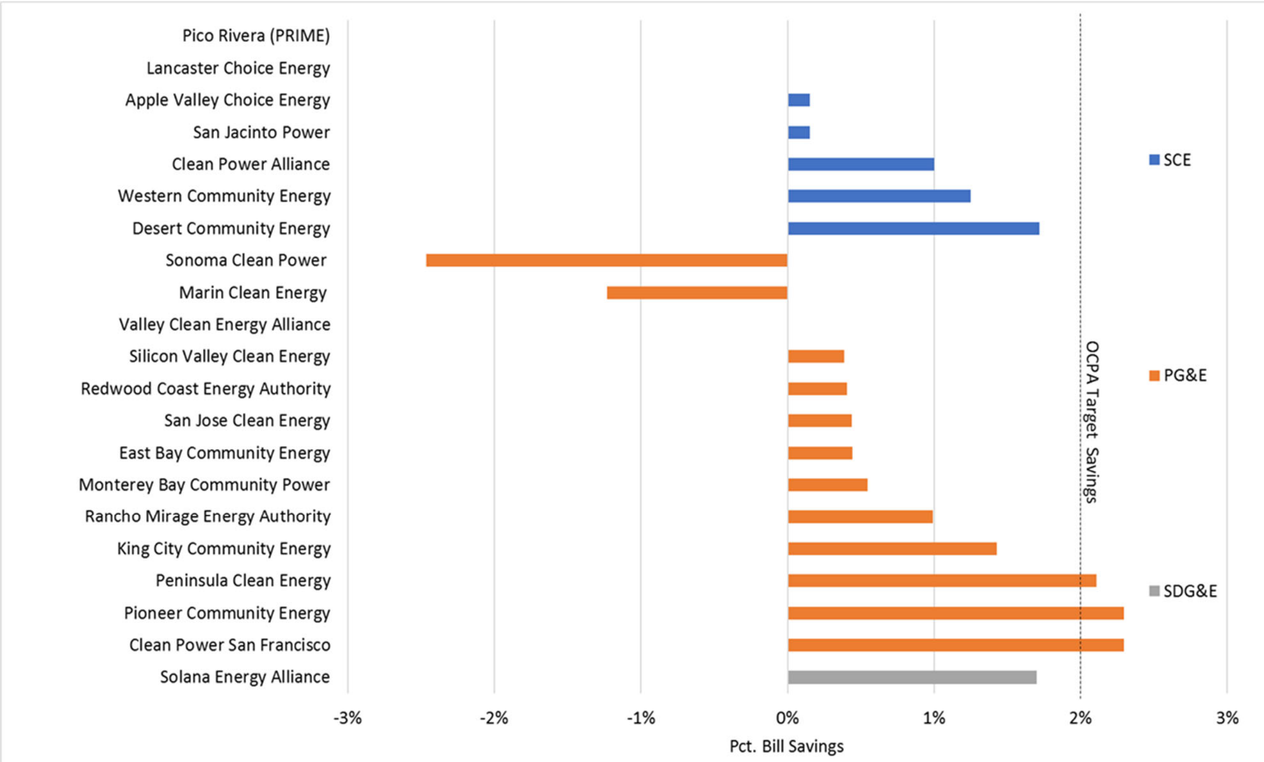
To assist customers, each CCA must offer a "Joint Rate Comparison" document that summarizes what an average monthly bill would be for each rate schedule that the CCA offers and the analogous rate and average bill available from their incumbent utility. These can be found on both the CCAs' and utilities' websites.[22] Based on these Joint Rate comparisons, Figure 14 shows the residential rate savings currently offered by operating CCAs relative to their host utility's rates. The values were calculated using the lowest cost rate offering for each of the CCAs and their utility's base rate (i.e., not a utility green tariff).

As the figure shows, none of the CCAs in SCE's territory and only three state-wide are currently offering a residential rate discount equal to or greater than 2%-- the target savings level of OCPA. Two CCAs in Northern California, in fact, have residential rates that are currently higher than their host utility.

These data support MRW's assessment that the margins in the next few years will likely be particularly tight for CCAs. As such, we are skeptical that OCPA will be able to offer the full 2% savings until 2023 or later.

[22] E.g., https://cleanpoweralliance.org/wp-content/uploads/2020/11/SCE-and-CPA-Joint-Rate-Comparison-October-2020-2018-Vint.pdf ; https://www.sce.com/sites/default/files/inline-files/SCE%20and%20DCE%20Joint%20Rate%20Comparison%20Effective%20April%2013%202020%201.pdf

Figure 14. CCA Residential Rate Savings as of January 13, 20201 (lowest cost CCA offering versus standard utility rate)



Chapter 4: Review of Implementation Plan

This section reviews the analytical approach, assumptions, and results of the OCPA Implementation Plan pro forma financial analysis and compares the key assumptions and results against the independent analysis conducted by MRW. Table 9 summarizes MRW's findings on the financial analysis underlying the OCPA Implementation Plan. Each entry is discussed in the following sections.

Table 9. Implementation Plan Assumption Summary

		Conservative	Reasonable	Potential Issue
	Modeling Approach		✓	
Load Assumptions	Load Forecast		✓	
	Line Losses	✓		
	Opt-Out Rate	✓		
CCA Power Assumptions	CCA Power Portfolio		✓	
	Wholesale Power Prices		✓	
	Renewable Power Prices		✓	
	RA Costs		✓	X
CCA Admin. and Other Cost Assumptions	Startup Costs		✓	
	Financing Costs		✓	X
	Admin. Costs		✓	
SCE Rate Assumptions	PCIA	✓		
	SCE Generation Rate		✓	X

Implementation Plan Approach

The Implementation Plan's financial analysis approach is sound and complete. It includes all the necessary expense and revenue categories and modeled a CCA program's pro forma cash flow accurately.

Implementation Plan Assumptions

This section reviews each of the major assumptions that the Implementation Plan makes and opines on the reasonableness of the assumptions. While most of the assumptions made by the

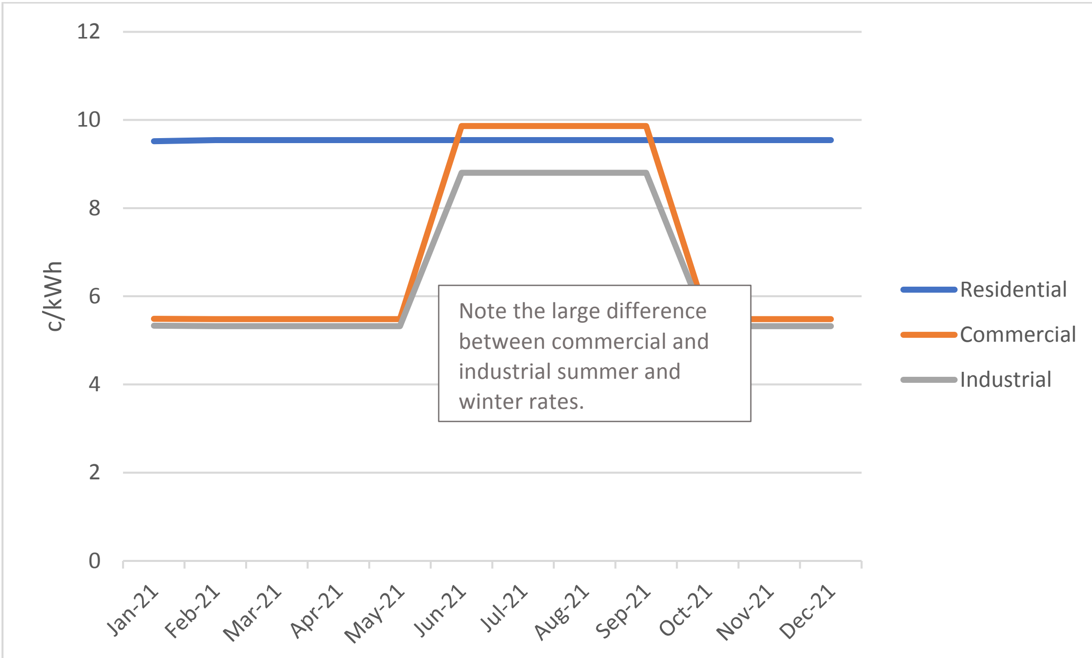
Implementation Plan were reasonable, two of the assumptions were understated or outdated. Additionally, many of the assumptions that the Implementation Plan characterizes as "conservative" MRW would consider reasonable, but not necessarily conservative.

Opt-Out

The magnitude of the costs and revenues a CCA program incurs depends upon the electric load that it serves. MRW finds the Implementation Plan's load analysis and forecast to be reasonable-to-conservative. The Implementation Plan's forecast begins with actual electric load data provided by SCE and assumes conservative opt-out rates: 5% for residential accounts and 10% for commercial/industrial accounts. (That is, 5% of eligible residential customers and 10% of eligible commercial customers would choose not to take service from OCPA). With one notable exception, opt-out rates seen by recent CCA program launches have been less than this, making the assumption conservative. The exception is the Clean Power Alliance of Southern California (CPA), the CCA that serves Los Angeles and Ventura counties, which experienced a much higher opt-out rate, closer to 50%, for its largest industrial customers. This was because CPA chose not to offer rates that were lower than SCE's for this customer class, but instead chose to set rates at levels equal to CPA's cost to provide power to them. Because the CPA rates were higher, and this class is especially sensitive to power costs, a large fraction of the industrial customers declined to take service from CPA. (This issue of competitive rate setting is discussed in greater detail in the Risk section of this report.)

The Implementation Plan shows that OCPA would not offer service to all its customers at once, but would instead offer service in three phases: commercial and industrial customers in Phase 1 (April); and residential customers in Phase 2 (October); and those customers with net-metered solar in Phase 3 (to be determined). This roll-out is sound for three reasons. First, it is simpler to begin serving only a small number of customers, so as to work out the metaphorical kinks on less sensitive accounts before rolling out to the general public. Second, due to SCE's rate design, CCA revenues for the larger commercial classes in SCE's territory are much higher in the summer months than in the winter or spring (Figure 15). Thus, it can be advantageous to phase in the commercial loads before the summer to take advantage of the higher margins. Because of the higher margins in the summer months, MRW suggests that the OCPA consider delaying Phase 1 to June when the rates are higher rather than in April, when SCE's generation rates are very low.

Figure 15. SCE Monthly Average Generation Rates (2021)[23]



Third, since the CCA's rates will, at least initially, be tied to SCE's, it is better to phase in new customers a month or two after SCE's rates are set. For example, SCE implements major rate changes, including the PCIA, at the beginning of the calendar year. What exactly those January 1 rates will be is not fully known until late December. Thus, if the CCA was launching on January 1, too, it would have to estimate what SCE's rates would be months in advance in order to go through its own rate-setting process. These guesses could very well be wrong and require an adjustment within the first months of service, a logistical and customer-relations gaffe better avoided.

Power Costs

As the Implementation Plan notes, around 90% to 95% of a CCA's program's costs are associated with the procurement of power. As such, the assumptions concerning the costs, sources, and mixes of the power are particularly important.

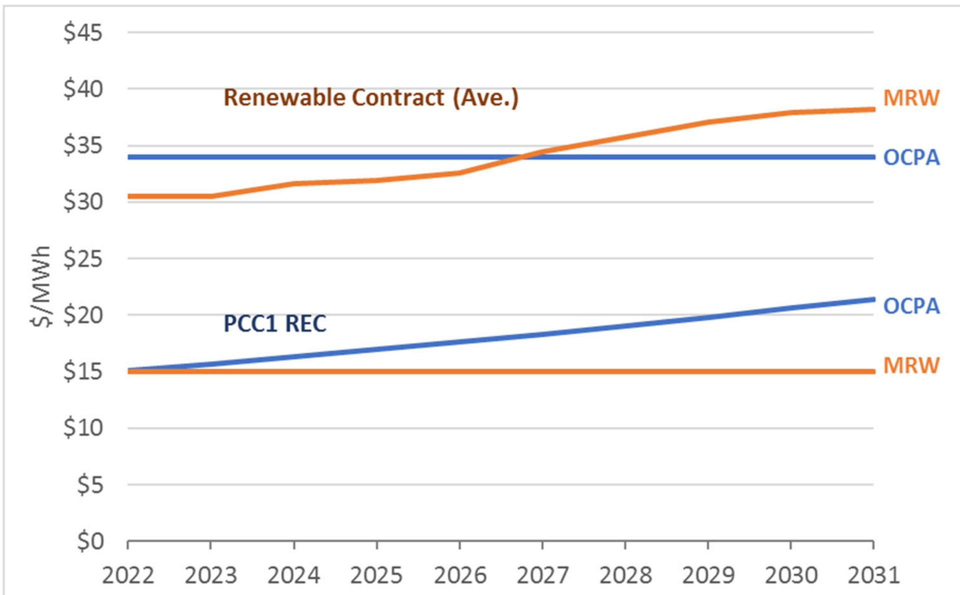
Wholesale Power Prices. The Implementation Plan relied upon a reputable source for wholesale power prices, S&P Global, which is consistent with MRW's selected forecast of long-term wholesale power prices in California.

Renewable Power. Given the total amount of renewable power being purchased in each scenario, the next question is whether the Implementation Plan's assumed sources of renewable

[23] These projected rates are based on the PG&E rates effective on January 1, 2021.

power and the associated costs are reasonable. The Implementation Plan's approach to renewable power costs differed from MRW's. Unlike MRW's analysis, which assumes explicit types of renewable power (PCC1 RECs, stand-alone solar, wind, solar+storage), the Implementation Plan assumed a simple combination of PCC1 RECS and unspecified "renewable" contracts. Figure 16 compares the MRW renewable power cost assumptions and the assumptions built into the Implementation Plan. While the two differ, the Implementation Plan's assumptions appear reasonable.

Figure 16. Comparison of Renewable Resource Costs



Other Power Procurement Related Costs

As discussed, the OCPA must demonstrate it has enough physical power supply capacity to meet its projected peak demand plus a 15% reserve margin, on a monthly basis. The Implementation Plan assumes the cost of basic ("system") RA to be $6.50/kW per month, escalated at 3% per year. While this is higher than the value used in the CCA Feasibility Study for the City of Irvine,[24] it is at the low end of what we would consider reasonable.

In addition to the system RA, all utilities and CCAs must all meet **local** capacity requirements to meet contingency needs in locally constrained areas (i.e., areas that need to have generation located within it because there is not enough transmission alone capacity to serve that area's needs). The Local RA requirement is based on the CAISO's assessment of the generation

[24] See links at https://www.cityofirvine.org/energy/community-choice-energy

needed in the local area. Beginning with the 2020 compliance year,[25] the Local RA requirements are set three years ahead and updated each year.[26]

On June 11, 2020, the CPUC adopted a framework (D. 20-06-002) that fundamentally changed the requirements for Local RA. That decision designated PG&E and SCE to be responsible for all the Local RA in their respective service areas, beginning in 2023. Therefore, SCE will be responsible for all the Local RA for OCPA and all other CCAs within its service area. This has two implications for the Implementation Plan's financial analysis. First, the analysis should not reflect any local RA costs beginning in 2023. Second, the policy change would also reduce SCE's generation rate. (This can be seen in Figure 17, where MRW's forecast slightly decreases in 2023 while in the Implementation Plan forecast the 2023 SCE rate increases.)

From the perspective of OCPA competitiveness with SCE, these two impacts tend to cancel each other out. Therefore, while the Implementation Plan does not correctly address Local RA, it does not change in the competitiveness position of OCPA.

CCA Operating Costs

As noted, ~95% of a CCA's costs are associated with power procurement, leaving the remaining 5% with CCA operating costs. The Implementation Plan thoroughly presents what types of activities a new CCA program should expect along with providing reasonable detailed estimates for the costs of those activities.

CCA Financing

The Implementation Plan anticipates "one or more rounds of financing, inclusive of prospective direct term loans between OCPA and its Member Agencies, will be necessary to support OCPA Program implementation," with any subsequent capital requirements met through OCPA's accrued financial reserves.[27] MRW understands that "loans from its Member Agencies" refers to the $2.5 million loan from the City of Irvine. OCPA currently projects repaying this loan by 2027, subject to change based on final power prices.

The Implementation Plan projects that its full start-up and working capital requirements for the OCPA Program will be $15.5 million, or $13 million beyond the Irvine loan. The Implementation Plan assumes that the remaining financing will be primarily via a short-term loan or letter of credit, which would allow OCPA to draw cash as required. Requisite financing would need to be arranged no later than the first quarter of 2021.

[25] The "compliance year" is the year in which the RA resources are used to meet the LSE's RA requirements for that year. For example, an LSE must demonstrate in 2019 that it has adequate RA capacity under contract for the 2020 RA compliance year.
[26] Note that Local RA capacity is a substitute for System RA capacity. However, the converse is not always true, meaning that System RA capacity might not help an LSE meet its Local RA requirements.
[27] Implementation Plan, page 36.

MRW finds the start-up cost estimate to be reasonable, but the working capital amount to be low. The Implementation Plan assumes 30 days of cash or line of credit. MRW expects that a financer would require something closer to 60 days of working cash. Second, MRW notes that in addition to the loan by Irvine, OCPA's financer will likely require a guarantor to any short-term loan or line of credit. Section 1.3 of the draft Loan Agreement between the City of Irvine and OCPA includes an agreement by Irvine to post "necessary cash collateral, not to exceed \$5,000,000, in order for the Authority to secure a credit facility for its Launch Costs for additional working capital associated with power procurement and operational support." Collateral in excess of the \$5 million will likely have to be from an OCPA Member or Members.

The experience of the most recent large CCA formed, San Diego Community Power (SDCP), is instructive of what is currently required for CCA financing. Because of its projected narrow operating margin—which is similar to that shown in the Implementation Plan—and general uncertainties facing CCAs, SDCP's finance provider required SDCP to have \$5 million in collateral in order for it to provide a \$5 million pre-launch loan plus a \$35 million line of credit.[28] OCPA's load is projected to be about 62% of the load of SDCP. SDCP required \$40 million initial line of credit. Simply scaling SDCP's requirement down to OCPA suggests an initial bank load/line of credit around \$25 million.

We note that Irvine has agreed to provide up to \$5 million collateral and a loan guarantee if required for the power purchase loan requirements. (Exhibit D, section 1.3 of the JPA agreement). While Irvine's commitment may likely provide a sufficient backstop for OPCA financing, it cannot be known until OCPA secures financing.

SCE Rates

Critical to the cost-effectiveness of OCPA is the rates it can offer relative to those offered by SCE. Thus, the forecast of SCE's generation rates and PCIA are equally as important as the forecast costs to operate the CCA program.[29] The Implementation Plan appears to perform its forecast of SCE generation rates by starting at the known 2020 SCE generation rates and escalates them at 2% per year.

Figure 17 shows the Implementation Plan's and MRW's rate forecast. While the two are relatively consistent, MRW's is about 5% (0.4¢/kWh) lower than that shown in the Implementation Plan. A 0.4¢/kWh decrease in rates translates to a \$13 million decrease in CCA revenue, which could in some years hamper the OCPA's ability to offer its target rate savings.

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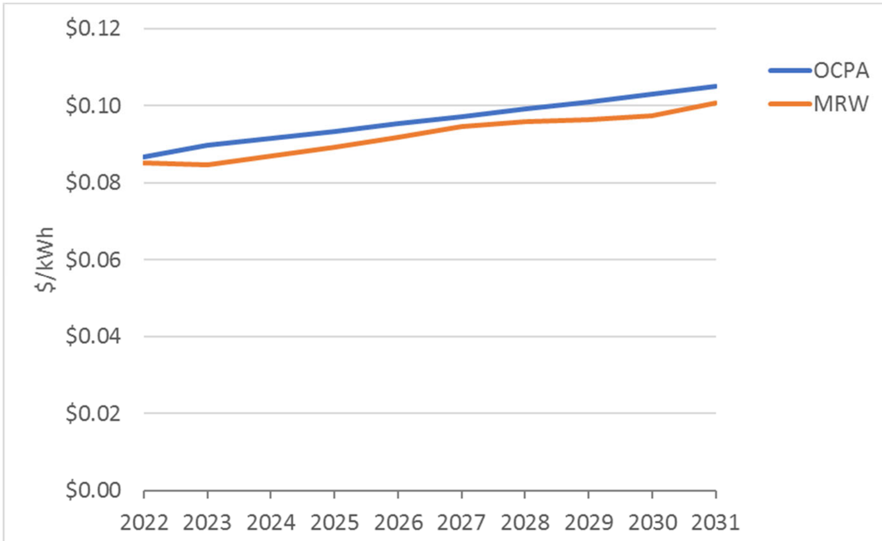
[28] See SDCP April 23, 2020 Board Packet, Staff Report on Item 4, at https://www.sdcommunitypower.org/board-meetings.

[29] Recall, for a customer to financially benefit from CCA service, the CCA rate plus the PCIA must be less than SCE's generation rate.

However, as discussed below, these lower generation rates would be offset by the Implementation Plan's very conservative PCIA assumption discussed below.

Figure 17. SCE Generation Rate Forecasts



PCIA

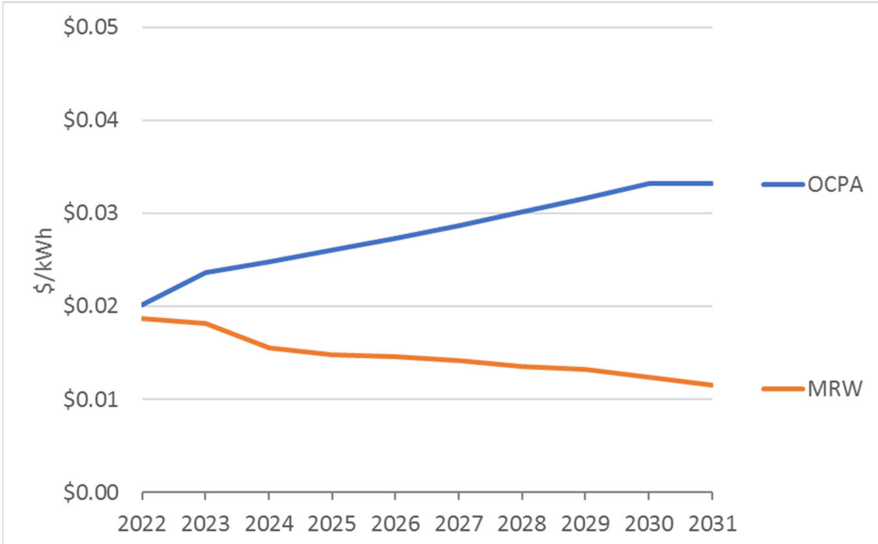
The Power Charge Indifference Adjustment (PCIA) is a fee charged by SCE to prevent customers that remain with SCE bundled service from paying for energy generation procured on behalf of customers that have since switched to CCA service. More specifically, it pays for the above-market costs of SCE generation resources that were acquired, or which SCE committed to acquire, prior to the customer's departure to CCA. Bundled customers also pay the PCIA, but it is embedded into the commodity portion of their total rate.

The PCIA is the single largest uncertainty in a CCA analysis. It can vary significantly from year to year, depending upon the wholesale power market, the costs of RA, the costs of renewables, and how well the prior years' PCIAs collected the correct amount so as to keep non-CCA customers whole. It can increase up to 0.5¢/kWh (roughly 25%) year over year due to market changes but can increase even more due to insufficient funds being collected in the PCIA.

The Implementation Plan starts with the current PCIA and escalates it at 5% per year through 2030.

As seen in Figure 18, the PCIA assumption in the Implementation Plan differs markedly from MRW's PCIA forecast. The two differ because MRW modeled the PCIA in a bottoms-up fashion, using the commission prescribed formula with assumptions consistent with the rest of the forecast, while the Implementation Plan escalated current PCIA rate. As shown below, the Implementation Plan's assumed PCIA is very conservative relative to MRW's forecast.

Figure 18. PCIA Rate Forecasts



Conclusions

Overall, the assumptions and analysis in the Implementation Plan are sound. However, we note the following concerns. First, the Implementation Plan does not address the changing state policies concerning Local RA. Second, the Implementation Plan's generation rate is on average about 5% lower than MRW's forecast, while significantly overestimating the PCIA. The overestimated PCIA more than makes up for the low generation rate, so the net effect is conservative. Third, MRW believes that the Implementation Plan may be understating the financing assumptions for launching a CCA. While Irvine's commitment to provide the startup loan and financial collateral may likely provide a sufficient backstop for OPCA financing, it cannot be known until OCPA secures financing.

Chapter 5: Risks & Mitigating Strategies

As discussed so far, there are clear benefits to CCA formation, but there are also risks. This chapter lists many of the larger risks that OCPA would face—and in fact all CCAs must deal with—along with summaries of how the CCA can address the risk. If Huntington Beach were to pursue CCA, it should create a risk management plan that would flesh out more specific risk policies and proceedings.

Financial Risk to City

A single-city CCA is assumed to be formed as a financially independent enterprise, with no dollars flowing into or out of the City's general fund. As such, the general fund cannot be drawn upon by the CCA's creditors, nor can CCA dollars flow into the general fund.

In the event that Huntington Beach joined OCPA, the JPA agreement defines the rights and responsibilities of each member of the CCA. With respect to financial support, Section 5.6 of the OCAP JPA agreement addresses Member contributions and payments. That section explicitly states, "except as otherwise specified herein, the Parties are not required under this Agreement to make any financial contribution of payments to the Authority, and the authority shall have no right to require such a contribution or payment." (§5.6) It goes on to say, "Unless otherwise agreed to by the Parties, the debts, liabilities and obligations of the agency shall not be the debts, liabilities and obligations, either jointly or severally, of the members" of the Authority. (§5.7) Still, a OCPA Member may, "in its sole discretion," agree to assume of the Authority's debts, liabilities, or obligations. (§5.7) (Note that MRW is not a law firm and does not offer a legal opinion as to the financial obligations of OCPA Members to the Authority.)

Nonetheless, starting up a CCA often requires a credit-worthy entity to backstop its initial financing. Some, such as CleanPowerSF, use the balance sheet from its existing power enterprise to backstop initial financing. Others have relied upon their host city or county as a backstop to initial financing. For example, MCE's initial bank loans for working capital were guaranteed by Marin County and the Town of Fairfax. After approximately six years, the CCA had demonstrated its creditworthiness and the guarantees were lifted. Still, the JPA cannot place any financial obligations or risks onto any of its members without that member's approval.

Opt-Out Risk

Customers may choose to opt-out of a CCA service before or during their transfer to CCA, or in fact at any time. (Reduced CCA participation due to high rates is addressed in Section B, below). The opt-out risk comes at two district time periods. The first is the initial roll-out of the CCA program. The most recent CCA launches have experienced only very modest opt-outs: around two to three percent of the eligible customers have elected not to take service from their CCA. If there are negative communications to Huntington Beach citizens and businesses during the initial roll out (e.g., bad press of some sort), then the opt-out rate could increase. Second, customers could choose to leave CCA service after the initial opt-out period. The most likely driver of this opt-out risk is expanding Direct Access (DA) eligibility, which is addressed in more detail below.

***Mitigation**:* The experience of the prior CCAs suggests that opt-outs at the beginning of service tend to be in a relatively narrow range, allowing for some predictability in initial opt-outs. In addition, prudent power procurement strategies will allow for a reasonable uncertainty in load, especially uncertainty associated with DA expansion, without having to either dump power at a loss or purchase excessive amounts at high spot market prices. CCAs also can charge an "exit fee" akin to the PCIA to customers who have left CCA service after power contracts have been signed to serve their load, but to date none have been imposed.

Rate and PCIA Uncertainty

A primary goal of a CCA is to offer power to Huntington Beach residents and businesses at a competitive price relative to SCE. In this circumstance, competitiveness is tied to the rate offered by SCE. A number of factors can cause OCPA's net power costs to exceed SCE's costs. OCPA will have in place risk management plans and options to both mitigate these risks by lowering rates passed on to customers back down to a competitive rate as well as to address unexpected risks.

Changes to SCE Generation Rates: There could be circumstances that result in SCE's generation' rates being less than OCPA's. Assuming that SCE's rates are based on its cost of service, OCPA obviously has little or no ability to influence the rates that SCE offers.

Mitigation: While OCPA has little ability to affect SCE's generation rates, it can take proactive steps to mitigate the impact of reductions in SCE's generation rate. These steps are discussed below.

Changes to SCE's PCIA Rate: Assembly Bill 117, which established the Community Choice Aggregation program in California, included a provision that states that the customers that remain with the utility should be "indifferent" to the departure of customers from utility service to CCA service. This has been broadly interpreted by the CPUC to mean that the departure of customers to CCA service cannot cause the rates of the remaining utility "bundled" customers to go up. To maintain bundled customer rates, the CPUC has instituted an exit fee, known as the "Power Charge Indifference Amount" or "PCIA" that is charged to all CCA customers. The PCIA is intended to ensure that generation costs incurred by SCE before a customer transitions to CCA service are not shifted to remaining SCE bundled service customers.

Thus, for an OCPA customer to realize an economic benefit (i.e., pay the same or less for electricity), the sum of the OCPA charges plus the PCIA must be lower than SCE's generation rate.

Mitigation: The PCIA is established at the CPUC. To ensure that this charge is properly calculated and that it is correctly allocated to OCPA customers, it will be necessary for OCPA to monitor and possibly actively participate in the regulatory proceedings in which the CPUC sets the PCIA.

CPUC "Financial Security Requirement" Risk

Pursuant to CPUC Decision 05-12-041, a new CCA must include in its registration packet evidence of insurance or bond that will cover costs as potential re-entry fees, specifically, the cost to SCE if the CCA were to suddenly fail and be forced to return all its customers back to SCE bundled service. Currently, a bond amount for CCAs is set at $147,000.

This CCA bond amount covers SCE's administrative cost to reintegrate a failed ESP's customers back into bundled service, plus any positive difference between market-based costs for SCE to serve the unexpected load and SCE's retail generation rates. Since the CCA bonding requirement has been in place, retail rates have always exceeded wholesale market prices, and thus CCAs' bond requirements have been simply equal to the modest administrative cost.

Mitigation: During normal conditions, the CCA Bond amount will not be a concern. However, during a wholesale market price spike, the bond amount could potentially increase to millions of dollars. But the high bond amount would likely be only short term, until more stable market conditions prevailed. Also, it is important to note that high power prices (that would cause a high bond requirement) would also depress SCE's PCIA and would also raise SCE's rates, which would in turn likely provide the CCA sufficient headroom to handle the higher bonding requirement and keep its customers' overall costs competitive with what they would have paid had they remained with SCE.

Direct Access and Competitive Retail Services

The most likely driver of opt-out risk is expanding Direct Access eligibility. As noted earlier, about 15% of the load in SCE's territory is served through Direct Access, with an additional 3% likely to have occur in 2020 due to the limited expansion of the DA cap from SB 237**.** In addition to modestly expanding the availability of DA service, SB 237 also directed the CPUC to report to the Legislature by June 1 of 2020, a deadline that the Commission missed on how to open DA completely for all non-residential customers. The CPUC's report on how to fully open DA service was delayed due to the outbreak of COVID-19, and preliminary Staff Report was eventually issued in September 2020. The Staff Report recommended that ESP's demonstrate obligation compliance by submitting robust IRPs and meeting their procurement, RA, and RPS requirements before further DA is opened. If legislation directs further reopening of nonresidential DA, then a re-opening schedule of increments of 10 percent of eligible non-residential load per year should be used under the condition that each expansion meets IRP, RA, and RSP requirements and allows LSEs to fully comply with RA requirements. A fully opened DA market would allow any commercial or industrial customer to switch its provider to a third-party, potentially reducing OCPA's revenue and creating a mismatch between its wholesale power portfolio and the CCA's load.

Additional expansions are possible, if not likely. If they come to pass, CCAs will have to compete with the DA providers on price and/or other services.

***Mitigation**:* As stated earlier, CCAs' history suggests that opt-outs at the beginning of service tend to be minor. Prudent power procurement strategies will allow for a reasonable uncertainty in load, including potential DA expansion, without having to dump power or purchase power at high spot prices. CCAs also can charge an "exit fee" akin to the PCIA to customers who have left CCA service after power contracts have been signed to serve their load, but to date none have been imposed.

Energy Risk Management

A Load Serving Entity (LSE) that is formed as a CCA faces financial risk of procuring energy, capacity, Renewable Energy Credits (RECs) and carbon-free energy (if needed) at a cost that exceeds the revenue that it receives from its retail customers. The other risks that are faced by the CCA roll up into the overarching risk of buying products and operating the CCA at a cost that exceeds revenue.

Mitigation:The CCA must establish a sound risk management program that forms the structure for measuring, monitoring, and managing risk. This section describes the elements that comprise risk, components, and functions of a Risk Management Program, and approaches that can be used to manage risk. CCA Risk Management plans can be found on their respective websites.[30]

Legislative and Regulatory Risks

As noted above, the CCA must meet various procurement requirements established by the State and implemented by the CPUC or other agencies. Regulatory risk, which changes the rules under which CCAs operate, affects the CCA's ability to maintain stable procurement activities, manage costs to its customers, and compete with the local incumbent utility and direct access providers.

Regulation of the electric utility sector that affects CCAs at the federal level is provided by the Federal Energy Regulatory Commission (FERC) which regulates the CAISO and at the state level by the California Public Utilities Commission (CPUC) which implements legislation passed by the California State Legislature and signed into law by the governor. Although CCAs are not directly regulated by the CPUC but rather their own local governing bodies, the CPUC is tasked with implementing details of legislation signed into law.

The risk to CCAs is in changes in the regulatory environment that affects the CCAs ability to attract, compete for, and retain customers, the products that it has already procured, and procurement practices going forward. Major issues that are currently evolving include:

- Direct Access
- Resource Adequacy[31]

[30] E.g., San Jose Clean Energy: http://www.sanjoseca.gov/DocumentCenter/View/77619; Silicon Valley Clean Power: https://www.svcleanenergy.org/wp-content/uploads/2019/03/2019-Risk-Management-Policy-F.pdf.

[31] For example, on September 12, 2019, the CPUC issued a proposed decision requiring electric system reliability procurement for 2021-2023 in the Integrated Resource Planning proceeding, Rulemaking 16-02-007. That proposed decision directs Southern California Edison to procure 1,745 MW of Resource Adequacy with a start date ranging between August 1, 2021 and August 1, 2023. Although the decision is not final, if it holds, and Southern California Edison moves forward, it most likely will be long Resource Adequacy and will need to re-sell it or have it allocated to Load Serving Entities.

- Power Charge Indifference Adjustment
- Renewable Energy Purchase Requirement
- Power Content Label Reporting
- Central Procurement Entity
- Energy Provider of Last Resort (POLR)

These include procuring sufficient resource adequacy capacity of the proper type and meeting RPS requirements that are evolving.[32] Additional rules and requirements might be established. These could affect the economic performance of the CCA.

There are potential risks associated with legislative proceedings that affect the Power Charge Indifference Adjustment (PCIA), which is a fee ($/kWh) charged by IOUs to cover the generation costs incurred before a customer changed to a new service provider, such as a CCA. The fee fluctuates per year based on the difference between an IOU’s actual generation cost and the current market value of its generation portfolio. The PCIA charge also varies per customer based on the date or “vintage” they enrolled with an alternative provider. CCAs are concerned with changes in the PCIA since significant increases in the PCIA can affect the rate competitiveness of CCAs with IOUs.

Legislation that affects RA creates risks for CCAs since all CCAs, like IOUs and Energy Service Providers (ESPs), have RA obligations. These obligations require LSEs to procure a specific amount of capacity so that this capacity is available to the CAISO in order to ensure electric service reliability. Drastic changes in RA requirements, particularly increases in obligation, would concern any LSE, especially since recently there was a decrease in available resource adequacy capacity in 2019.

Due to the rise in wildfire risks over the past several years, CCAs are following legislation that addresses wildfire mitigation and public safety power shutoffs (PSPS). Some CCAs are focused on insulating their customers from potential wildfire risks and subsequent power shutoffs.

Mitigation*:* Regulatory and legislative risk can only be managed though close monitoring of the relevant proceedings at the CPUC and legislation in Sacramento and intervening where needed to advocate for the CCA. If Huntington Beach pursues CCA, the organization should consider teaming with other CCA, such as through the Cal-CCA trade organization on regulatory and legislative monitoring.

[32] Rules to establish RPS requirements under the new 50% RPS mandate established by SB 100 are currently being debated at the CPUC.

Chapter 6. Governance Model Options

In addition to selecting an operating structure, the City will decide between three primary governance options for the CCA:

1. Where the City is the sole government agency responsible for the CCA's creation and operation,
2. Participation with other agencies in a Joint Powers Agency (JPA), where multiple agencies share oversight responsibilities for the new agency; or
3. Joining an existing CCA JPA.

Forming a Single City Agency

In a sole jurisdiction approach, the City maintains full flexibility—and responsibility—for developing policies and procedures. This means that they can be tailored to and responsive to the City's stakeholders and constituents only and based upon their own objectives. The City would be responsible for setting policy priorities in general and making specific decisions about power generation, staffing policies, local economic development activities and strategies, the formulation of financial and debt policies, and the development of EE, demand response, electric vehicle (EV), and distributed generation programs. Along with greater autonomy, the City would assume all risk, liability, and costs associated with operating the CCA. In this case, the likely path would be for the City to establish the CCA as an enterprise fund, and work with appropriate legal counsel to explore options for controls and structural safeguards to insulate it and minimize risk to the City's general fund.

The City would need to establish the CCA as an enterprise. Enterprises are commonly used for public utilities such as electric, water and wastewater, or other city functions where a public service is operated and provided in a manner similar to a business enterprise, where fees and charges are collected for services provided, and accounting and budgeting are separate from a city's general fund. Setting the CCA up as an enterprise provides a structure where the revenues and expenditures are separated into different funds, budgeted for on their own, and reported on their own financial statements. In an enterprise, financial transactions are reported like business activity accounting; revenues are recognized when earned and expenses are recognized when incurred. Establishing an enterprise fund provides management and CCA customers with more visibility and accountability, and the ability to more easily separate and measure performance, analyze the impact of management decisions, determine the cost of providing electric service, and use this information to develop cost-of-service electric rates. Enterprise accounting will allow the City to demonstrate to customers, the public and other stakeholders, that the cost of power is being recovered through its rates, and not being subsidized or comingled with other City funds or functions.

Within the City-Only option, the City would determine if it is to be a fully in-house operation with existing or added City Staff, or if the City would outsource some of all of the activities, with the City only administering contracts and managing vendors. Examples of some of the categories of operating activities that would need to be performed in-house or outsourced:

- Power procurement, scheduling
- Finance, budgeting, and accounting
- Coordinating with SCE on billing
- Customer service
- Communications, outreach and public relations
- Specific programs such as demand response, EE, EV, or rooftop solar PV
- Regulatory monitoring and compliance, CPUC filings, etc.

The likely best short-term option would be to outsource the highly technical functions, and maintain some of the management, planning, and other public-facing functions like communications in-house. The range of options depends upon the degree of operating control the City wishes to maintain, the costs associated with maintaining those functions, and the degree of risk it is willing to accept on its own, or delegate to (and pay) third-party providers to assume.

No matter the amount of outsourcing, a CCA of Huntington Beach's size would eventually (i.e., within the first three years) require a core staff of experienced professionals for CCA-specific operations. This would include:

- Executive Director
- Finance Director
- Data/IT manager
- Power resources/procurement director
- Customer relations/outreach director
- Account service manager
- General Counsel
- Regulatory affairs director

If the CCA were to pursue additional services, such as their own energy efficiency, rooftop solar, or other customer-facing program, more managers would be needed. Additionally, many of these would be supported by 1 or 2 support analyst professionals, some of whom could be shared with other Huntington Beach departments.

All larger CCA have dedicated staffs of 15 – 40 employees. For example, San Jose Clean Energy (SJCE) is a larger city with an enterprise CCA. Its planning documents show an eventual staff of 20.

Forming or Joining a Joint Powers Agency

The second option would be the formation of a JPA, where the JPA is an independent agency that operates on behalf of the public agencies which are party to its creation. This is the option that OCPA is currently offering the City of Huntington Beach. In this approach, the City effectively shares responsibility with the other agencies participating in the JPA. The divisions of these responsibilities and the sharing of decision-making authority would be determined at the time the JPA is created. Other critical ‘ground rules’ would also need to be negotiated and memorialized, such as financial and possibly staffing commitments of each participating agency, and the composition of the board and voting procedures.

Sections 6500 to 6536 of the California Government Code constitute the enabling legislation for Joint Powers Authorities, and the Public Utilities Code allows a CCA program to be carried out under a joint powers agreement between entities that each have the capacity to implement a CCA program individually. A JPA may be formed when it is to the advantage of two or more public entities with common powers to combine resources, or when local public entities wish to pool with other public entities to save costs and/or gain economies. It can also be employed to provide the JPA with powers and authority that participating entities might not have on their own. A JPA is a legal and separate public entity with the ability to enter contracts, issue debt, and provide public services, among other things, and like the City, it would have broad powers related to the operation and management of the CCA, and the study, promotion, development, and conduct of electricity-related projects and programs.

The JPA structure may reduce the risks of implementing a CCA program to the City by immunizing the financial assets of the City and the other participating agencies, and distributing the risks and costs associated with the CCA among the participating entities. It could also provide the benefits of scale and economy for certain aspects of CCA operation, such as power procurement or back office billing and accounting functions.

A CCA operated under a JPA could benefit from increased negotiating and buying power for power purchases, access to better financing terms for borrowing, and operating efficiencies gained by combining back-office functions such as billing and accounting. These benefits would accrue to customers through better pricing for power and debt, and ultimately more competitive electric rates. A larger JPA could also wield more political influence, which could be beneficial when participating in CPUC or other regional or state regulatory, legislative, or policy making activities.

Key tradeoffs to the benefits of a JPA are that decision making is allocated amongst the parties and management independence is diminished. Objectives of participating agencies will likely differ, and reduced autonomy can manifest when setting priorities for local generation, economic development activities, and the importance of support programs. When the JPA is formed, a Board must be appointed to set policy and make decisions. The makeup of this board is subject to negotiation among the participating entities but would likely be made up of elected officials from each participating agency. The process of determining the makeup of the board and each respective members’ voting weight can be based on several factors, such as the percentage of customers or load or relative financial contribution, but in any case, decision making is certainly more complicated. The number of stakeholder interests and priorities are multiplied, and in many cases, reaching consensus on key decisions is more complex and time-consuming than if only one agency were involved.

Chapter 7. Conclusions

Overall, establishing a CCA in Orange County, such as the OCPA, appears feasible. Given current and expected market and regulatory conditions, a CCA should be able to, over the long run, offer its residents and business customers electric rates that are less than that available from SCE.

Sensitivity analyses suggest that these results are relatively robust. Nonetheless, the margins are tight in the first few years which could prevent the OCPA from offering a rate discount or contributing to financial reserves. This conclusion is supported by the rate savings offered by the current CCAs, only three of which are offering residential rate savings of 2% (the OCPA target) or more.

OCPA could conceivably reduce the amount greenhouse gases associated with the consumption of electricity in Orange County, but only under certain circumstances. Because SCE's supply portfolio has significant carbon-free generation (large hydroelectric and nuclear generators), the CCA must contract for significant amounts of carbon-fee power above and beyond the required qualifying renewables in order to actually reduce Orange County's electric carbon footprint. Therefore, if carbon reductions are a high priority for the CCA, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed.

Huntington Beach's two options for CCA are forming a City-only enterprise or joining OCPA. The primary benefits of forming a Huntington Beach-only CCA are more local control over procurement practices and budgets and being able to offer services that are better tailored to Huntington Beach. The primary benefits of forming or joining OCPA are forgoing the need for the City to provide startup funding and loan guarantees, faster implementation, reduced risk, and reduced administrative burden on City Staff, both in CCA formation and in ongoing management.