CITY OF
LONGBEACH

Long Beach Energy Resources
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R-20

December 10, 2019

HONORABLE MAYOR AND CITY COUNCIL
City of Long Beach
California

RECOMMENDATION:

Receive and file a report on the feasibility of a Long Beach Community Choice Aggregation (CCA);

Direct the City Manager to continue to monitor the energy market/regulations and report to the City Council annually or sooner if substantial market changes occur;

Direct the City Manager to prepare a study that analyzes the potential CCA governance options of forming a stand-alone City enterprise, creating a new Joint Powers Authority (JPA), or joining an existing JPA;

Direct the City Manager to perform community outreach regarding the CCA concept along with potential benefits and risks to customers, as well as to gain feedback on how supportive the community might be of a Long Beach CCA;

Direct the City Manager to continue the City's partnership with Southern California Edison to raise awareness of existing programs that provide Long Beach residents and businesses with various options to purchase a greater mix of renewables and utilize energy more efficiently; and,

Defer for two years any decision whether to participate in a CCA, in any format, or sooner if new information becomes available solidifying benefits, to allow for possibly increased stability in the California electricity market, which will lessen possible risk to residents and businesses. (Citywide)

DISCUSSION

State law allows the City of Long Beach (City) to form or join a Community Choice Aggregation (CCA) enterprise to replace Southern California Edison (SCE) in procuring electricity as a commodity on behalf of all Long Beach residents and businesses. Under a CCA, SCE would still provide the transmission and distribution of the electricity (power lines, poles, substations, etc.) and would provide billing services to residents. A Long Beach CCA would involve annual electrical commodity purchases of approximately $100 to $140 million. While the City's natural gas and water utilities also expend substantial dollars in purchasing of their respective commodities, it should be noted that purchasing power is a much more complex endeavor as electricity is largely produced and consumed instantly, with limited ability to store for later usage. With this increased complexity in power purchasing comes increased financial risk.

To assess whether the creation and operation of a CCA would be potentially beneficial, outweighing the costs and risks to both the City and its residents/businesses, the City Council authorized City staff to hire various expert consulting firms to prepare a CCA Feasibility Study (Study) (Attachment). MRW & Associates (MRW) served as the lead consulting firm in the Study's preparation.

Key subject matters in the Study included likely net savings (or costs) to residents in their monthly electricity bill, greenhouse gas (GHG) emission reduction, forecasts of power needs/supplies and purchasing costs, financial risks and possible mitigation strategies, economic benefits, the regulatory environment, and start-up issues.

Impact on Customers' Monthly Electricity Bills

If everything proceeded as intended with a CCA, the CCA would generate monthly savings, as measured by comparing the CCA's power purchase costs (plus the required payment of exit fees to SCE) against SCE's generation charges that would be paid if the CCA did not exist. The CCA's savings could potentially be used to reduce the electricity rates paid by Long Beach residents and businesses and/or, if desired, provide some funding for increased purchases of renewable power or funding of alternative energy incentive programs such as solar installations or electric vehicles.

However, the uncertainties in the current electric energy market, combined with very recent California Public Utility Commission (CPUC) actions, make it uncertain as to whether the CCA will save much money, if at all. As a point of comparison, the two primary CCAs currently in operation in Southern California offer savings of roughly 1 percent to 2 percent to their residential customers in comparison with SCE's rates for equivalent renewable power content of 37 percent. If a Long Beach CCA chose to provide its customers with a default power supply with greater renewable content, say 50 percent or 100 percent, this would likely result in the Long Beach CCA charging Long Beach residents and businesses rates higher than they currently pay to SCE.

For the foreseeable future, a Long Beach CCA could not serve its largest industrial customers, representing approximately 25 percent of the entire Long Beach electrical load, at rates competitive with SCE. Therefore, this component of the Long Beach customers would remain customers of SCE and not be served by a Long Beach CCA. This large component of industrial load makes Long Beach relatively unique among cities considering the establishment of a CCA.

Unfavorable market or regulatory conditions could result in a Long Beach CCA having a higher cost than SCE for electricity purchases, possibly resulting in Long Beach residents and businesses paying higher electric bills than if they had remained fully bundled customers of SCE. While not common, such situations have occurred with other CCAs, primarily during the initial years of their existence. Beyond the risk of higher electric bills for Long Beach customers is the risk of a substantial number of customers opting to leave the CCA and return to SCE. This could cause serious harm to the CCA if the CCA is financially burdened with supply contracts for customer load that has returned to SCE.

It is also very likely that most Long Beach residents and businesses are unaware of the CCA concept and how the risks and uncertainties involved with a Long Beach CCA might impact their monthly electric bills, positively or negatively. Most public information is largely about the potential benefits of CCAs while the alternatives and potential risks have generally not been as clearly described. If the City Council wishes to continue consideration of a CCA, a public outreach program on CCAs, their benefits, risks, and alternatives would likely be helpful in informing residents and businesses.

Greenhouse Gas Emission Reductions

The City's formation of a CCA would not inherently reduce GHG emissions, as SCE and a Long Beach CCA would be subject to the same State renewable requirements of reaching 60 percent by 2030 and the goal of 100 percent by 2045. Both a Long Beach CCA and SCE would be purchasing power in the same renewable energy marketplace. SCE's current supply portfolio includes 52 percent of its power from non-fossil fuel sources of which 37 percent is from renewable energy.

A Long Beach CCA, however, would have the ability to achieve greater GHG emission reductions than the State's requirements by deciding to purchase a dramatically greater amount of hydropower or renewable energy. While achieving greater GHG emission reductions, these greener power purchases would be at a potentially much higher price, reducing a Long Beach CCA's ability to offer rate savings to its customers. Additionally, as SCE is also required by law to move towards 100 percent clean energy, the City's formation of a CCA would, at best, make only a very modest incremental difference in the GHG savings.

For those Long Beach residents and businesses that are willing to pay a premium for greener power, they individually have the option today to take advantage of programs SCE offers that allow customers to specify how much of their energy use at their home or business is renewable energy, either 50 percent or 100 percent.

Local Economic Benefits

Depending upon the governance structure of a Long Beach CCA, the CCA would, at most, have roughly 10 to 27 employees, generating local economic activity as would any similarly sized small company. If the City formed its own CCA, a significant part of that economic activity would likely occur in Long Beach; if the City joined an existing CCA JPA, it is likely that little of that economic activity would benefit Long Beach as the employment would likely be outside of Long Beach.

Any net savings or net costs realized on customers' monthly electric bills would increase or reduce economic activity in Long Beach. However, because the level of net savings or costs are too uncertain, it is best to assume this aspect of a CCA's economic benefit is indeterminate at present.

Regulatory Environment and Market Conditions

The California electric industry is currently in a state of flux from which significant changes are expected to occur over the next two years impacting both CCAs and the Investor Owned Utilities (IOU's) such as SCE. Some of the causation factors include the wildfire catastrophes and impacts to State-wide transmission operations, the bankruptcy and possible dissolution of Pacific Gas and Electric (PG&E) in Northern California, the potential establishment of a new State agency to procure electricity, changes to the Power Charge Indifference Adjustment (PCIA) fees to CCA customers, as well as numerous other major energy regulatory issues currently evolving in California. These potential regulatory and industry changes could detrimentally impact the finances of a Long Beach CCA by millions of dollars annually.

Similarly, the California electric energy market is undergoing an evolution with factors such as the reduction in renewable energy costs over the past decade, the introduction of battery storage that will impact market conditions, and California's move to greater electrification. Each will create uncertain impacts to future power purchasing/supply decisions, further increasing risks. For example, electrification will increase demand, exacerbating the future challenges of insufficient power supplies to meet growing demands.

While the track record for CCAs in Northern California is more substantive, the introduction of large-scale CCAs in Southern California is very recent, only entering full service within the past year or so. This lack of well-established, large CCAs in SCE's territory makes it somewhat difficult to gauge the likelihood of a successful Long Beach CCA. Another significant difference is that PG&E has long been reviled by many of its customers in Northern California, and is now in bankruptcy, causing many customers to welcome any alternative to PG&E. However, customers in Southern California generally seem to have a more favorable perception of SCE, generally viewed as having responsibly served its customers for over a hundred years.

Start-Up Issues

CCAs have generally been able to start-up successfully and have returned start-up costs to investors. The start-up costs for a Long Beach CCA are estimated at $15 million. The City might need to invest $1 million to $5 million of that amount, likely from the General Fund. The repayment to the General Fund by the operational CCA would likely be within a year or so. The CCA would likely finance the remainder.

As part of start-up, the City would have a policy decision to determine whether to create a City utility enterprise that would act as a CCA, to join an existing CCA that was formed as a JPA, or to create a new JPA with one or more partners. There are various pros and cons of the alternatives and they have not been fully studied. Basically, a City enterprise CCA would provide the most local control over rates and program offerings but also incur the highest start-up costs and risks. Opting to join an existing JPA or forming a new JPA would likely give the City less control but reduce start-up costs and risk.

Working with SCE

SCE has been the electricity provider to Long Beach for over one hundred years. As the City continues to monitor and contemplate the formation of a CCA, the City should also look to continue to partner with SCE to better promote and support SCE's numerous existing green energy and energy efficiency programs of which Long Beach residents, businesses, and the City itself can take advantage. Importantly, such a partnership would not, in any way, prevent the City from forming a CCA at any time.

As previously mentioned, these programs include the ability today of Long Beach customers who want to be environmentally friendly to voluntarily pay a premium to have SCE purchase more renewable energy on their behalf, either 50 percent or 100 percent renewable energy. Another possible program is for the City to opt to become an anchor tenant for SCE's Community Solar program whereby all participating income-qualifying customers would receive a 20 percent discount off their monthly SCE electric bills.

Next Steps

Based upon the concerns, risks, and unknowns outlined in this letter, it is prudent that the City defer for two years any decision to participate in a CCA, in any format, or sooner if new insights become available that clarify the California energy market and regulatory direction. This decision to allow time to gain some stability and better information will lessen the potential risks that the formation of a Long Beach CCA may pose to residents and businesses.

During this postponement, City staff will continue to monitor the energy market and regulatory actions impacting CCAs. Staff will report to the City Council whenever substantial new information becomes available or major changes occur that might help provide direction in regard to deciding to move forward with a CCA.

So as to better be prepared if the decision is ultimately made to participate as a CCA, a study will be prepared that analyzes in detail the potential options of CCA governance structure, including a stand-alone City enterprise, creating a new JPA with another government agency, or joining an existing JPA. The study will provide the distinct advantages and disadvantages involved with each of these governance options.

Very importantly, the residents and businesses must be engaged through City outreach so that they can better understand the CCA concept, including both potential benefits and risks to themselves as electric customers. This outreach can also help determine how supportive, if at all, the community might be of a Long Beach CCA. The better informed residents are of the CCA concept, the better they can help determine the direction the City ultimately takes.

Lastly, the City will step up its ongoing partnership with SCE so as to increase residents' awareness and possible participation in already existing programs that allow for greater renewable power purchasing and energy efficiency opportunities. Staff will return to the City Council with a report on the various programs that the City and SCE will push out to the community. As mentioned before, any activity undertaken in conjunction with SCE will not preclude the City from any future participation as a CCA.

This matter was reviewed by Deputy City Attorney Richard F. Anthony and Finance Director/CFO John Gross on November 26, 2019.

TIMING CONSIDERATIONS

This item is presented to provide a timely response to a City Council request for a CCA feasibility study.

FISCAL IMPACT

Implementation of these recommendations is expected to cost approximately $60,000, with most of the cost associated with monitoring the energy market and regulatory activity and preparing updated reports. Moderate time for high-level staff would be required to implement the recommendations, mostly associated with the public outreach. Funding is expected to come from the Gas Fund as a continuation of the original Gas Funding for the feasibility study. Any actual CCA start-up would likely be funded from the General Fund. There is expected to be moderate time required for high-level staff to implement a start-up and it would likely have some adverse impact upon existing City Council priorities and staff's ability to address them in a timely manner. There is no job impact associated with this recommendation.

SUGGESTED ACTION:

Approve recommendations.

Respectfully submitted,

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DIRECTOR OF ENERGY RESOURCES

CHRISTOPHER J. GARNER
GENERAL MANAGER, LONG BEACH WATER

JOHN GROSS
DIRECTOR OF FINANCIAL MANAGEMENT

APPROVED:

THOMAS B. MODICA
ACTING CITY MANAGER

ATTACHMENT: MRW FEASIBILITY STUDY

ATTACHMENT

Feasibility Study: Community Choice Aggregation for the City of Long Beach

Prepared by:

MRW & Associates, LLC
1736 Franklin Street, Ste 700
Oakland, CA 94612

November 2019

With:

Community Choice Partners

Economic Development Research Group

Rincon Consulting

ZGlobal

This report was prepared by MRW & Associates. MRW has been working on 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.

The following firms provided specialized expertise:

Community Choice Partners prepared Chapter 5. Example of a Hypothetical 5-Year Cash Flow Analysis & Financial Strategy and contributed to Chapter 6: Risks & Mitigating Strategies and Appendix 2: CCA Energy Risk Management. Mr. Golding, president of CCP, also provided invaluable strategic guidance and review of MRW analysis and assumptions.

Economic Development Research Group prepared Chapter 7. Macroeconomic Impacts.

Rincon Consulting conducted the GIS analysis and prepared Appendix 1: GIS-Based Assignment of Parcel Scores for Potential PV Solar Development.

ZGlobal prepared the wholesale market power price forecasts and contributed to Chapter 6: Risks & Mitigating Strategies and Appendix 2: CCA Energy Risk Management.

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.

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List of Acronyms

AB	Assembly Bill
BNI	Binding Notice of Intent
CAAP	Climate Action and Adaptation Plan
CAISO	California Independent System Operator
CalCCA	California Community Choice Association
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CCA	Community Choice Aggregator/Aggregation
CCEA	California Choice Energy Authority
CEC	California Energy Commission
COS	Cost to Serve
CPA	Clean Power Authority
CPE	Central Procurement Entity
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CRR	Congestion Revenue Right
DA	Direct Access
DEG	Distributed Energy Generation
DOE	Department of Energy
DR	Demand Response
ECN	Energy Communications Network
EDI	Electronic Data Interchange
EE	Energy Efficiency
ELCC	Effective Load-Carrying Capacity
ESP	Energy Service Provider
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GIS	Geographic Information System
GTSR	Green Tariff Shared Renewable
GTSR-GR	Green Tariff Shared Renewable - Green Rate
GWh	Gigawatt Hour
IOU	Investor Owned Utility
JPA	Joint Powers Authority
kWh	Kilowatt Hour
LMP	Locational Marginal Price
LSE	Load Serving Entity
MT	Metric Ton
MW	Megawatt
MWh	Megawatt Hour
NEM	Net Energy Metering
OTC	Once-Through Cooling
PA	Public Advisor

PCIA	Power Charge Indifference Adjustment
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PV	Photovoltaic
RA	Resource Adequacy
REC	Renewable Energy Credit
RFO	Request for Offer
RFP	Request for Proposal
RMR	Reliability Must-Run
RPS	Renewable Portfolio Standard
SB	Senate Bill
SC	Scheduling Coordinator
SCE	Southern California Edison
SJCE	San Jose Clean Energy
SVCEA	Silicon Valley Clean Energy Authority
TAC	Transmission Access Charge

Executive Summary

Main Findings

The general conclusions of this study are as follows:

1. The analysis performed here suggests that Community Choice Aggregation (CCA) could potentially be financially feasible for Long Beach.
2. Nonetheless, there are key assumptions, such as market power prices and the cost to comply with the state's Resource Adequacy requirements, that remain uncertain that could negatively impact the financial performance and operations of a CCA. Some of these can be mitigated, such as wholesale power market price exposure through sound hedging and risk management practices. Others are more uncertain, such as regulatory changes.
3. Given Southern California Edison's (SCE's) rate design, the CCA cannot cost-effectively offer competitive rates to customers taking service at SCE Tariff TOU-8 subtransmission voltage (a subset of the largest industrial users). This means that a CCA would be better off deferring offering service to these customers until the CCA can do so without losing revenue or offering them rates that are higher than SCE's.
4. Simply 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 power from large hydroelectric facilities (which are carbon-free but do not qualify as "renewable" under State law) at a price premium or dramatically increase the renewable content of the power beyond that required by the State.
5. 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 sets state policy to have eligible renewable energy resources and zero-carbon resources supply 100% of electricity 2045. This effectively means that the difference between the electricity carbon content of the CCA, following the City's CAAP, and remaining with status quo utility service may not be significant.
6. Because the city is fully developed, there is only modest opportunity for developing grid-connected solar PV. This conclusion applies only to larger PV arrays and not to rooftop, net metered solar.
7. Long Beach's two primary options for CCA are forming a City-only enterprise or joining with the Clean Power Alliance (CPA), the CCA currently serving large portions of Los Angeles and Ventura Counties. The primary benefits of forming a Long Beach-only CCA are more local control over procurement practices and budgets and services better tailored to Long Beach. The primary benefits of joining CPA are the security and reduced risk of

joining with an already-operating entity and reduced administrative burden on City Staff, both in CCA formation and in ongoing management.

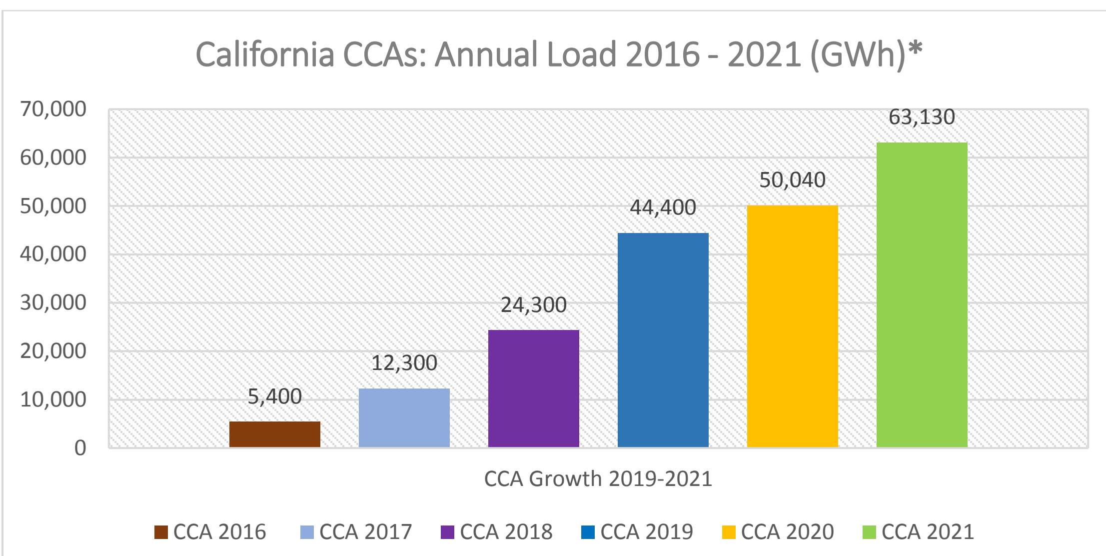
8. A Long Beach CCA can possibly result in economic and employment benefits to the region by potentially offering lower rates and directly employing residents. However, the CCA should not be seem primarily as a tool for local economic development; there are likely other, less complex and risky ways to pursue economic development goals.

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 delivery services at the same price and at the same level of reliability to customers taking their power from a CCA as it does for its own full-service customers.

CCAs are now quite common in California. There are currently 19 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, by 2021 CCAs are expected to serve over 63 GWhs in the State, 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[1]



*Figures for 2020/2021 are projections based on expected launches

[1] Figure courtesy of Cal-CCA.

To assess whether a CCA is financially feasible in Long Beach, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the City, this study:

- Quantifies the electric loads that Long Beach CCA could serve;
- Compares the rates that could be offered by the CCA to SCE's rates;
- Determines the GHG emissions impacts of a CCA;
- Calculates the macroeconomic development and employment benefits of CCA formation;
- Compares the benefits and risks of forming a city-only CCA or joining a neighboring CCA versus remaining on SCE bundled service;
- Discusses, and where possible, quantifies the risks to the City and its residents and businesses of CCA formation.

Loads and Forecast

Table ES-1, shows that the City's total annual electric load, not including those served by direct access,[2] is about 3.1 GWhs, or 3% of SCE's total load. This load is spread across almost 180,000 accounts.

Table ES-1. Potential Long Beach CCA Customers and Associated Load

	Customers	Annual Load (MWh)
Residential	158,480	746,292
Small Commercial	16,512	591,646
Medium Commercial	2,638	456,615
Large Commercial & Industrial		
On TOU-8 Sub-transmission	*28*	*853,323*
On other Tariffs	*78*	*366,780*
Total Large C & I	106	1,220,104
Other*	1,967	67,636
Total	**179,703**	**3,082,293**

*streetlights, traffic control, agriculture/pumping.

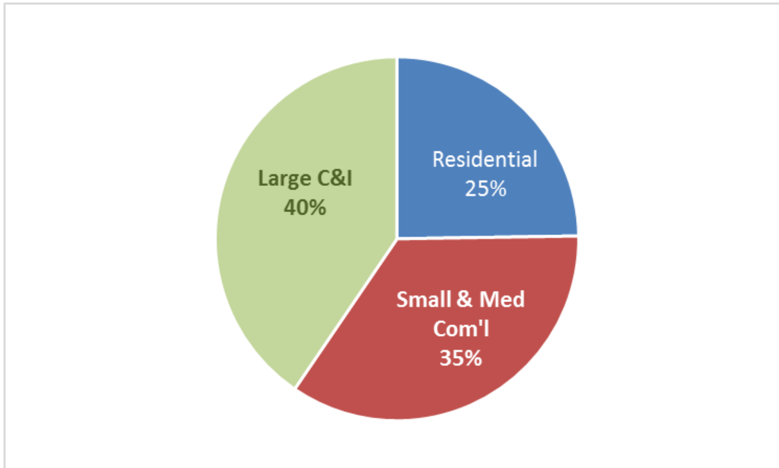
As shown in both the table and in Figure ES-2, a very large portion of the load, over 40%, is from the large commercial and industrial class.[3] This is unusual; most other CCAs have only

[2] The amount of DA service allowed in SCE's service area is capped by law. Due to existing contracts with their ESPs, DA customers are not likely to join a CCA. Thus, the pool of possible CCA customers is limited to those currently served by SCE.

[3] More specifically, from SCE Rate Schedules TOU-8 (Primary) and TOU-8 (Sub-transmission)

modest at best large commercial and industrial loads. The importance of this fact is discussed later in this report.

Figure ES-2. Long Beach Load Distribution



CCA Power Supply and Load Scenarios

Two hypothetical power supply scenarios were developed for this analysis:

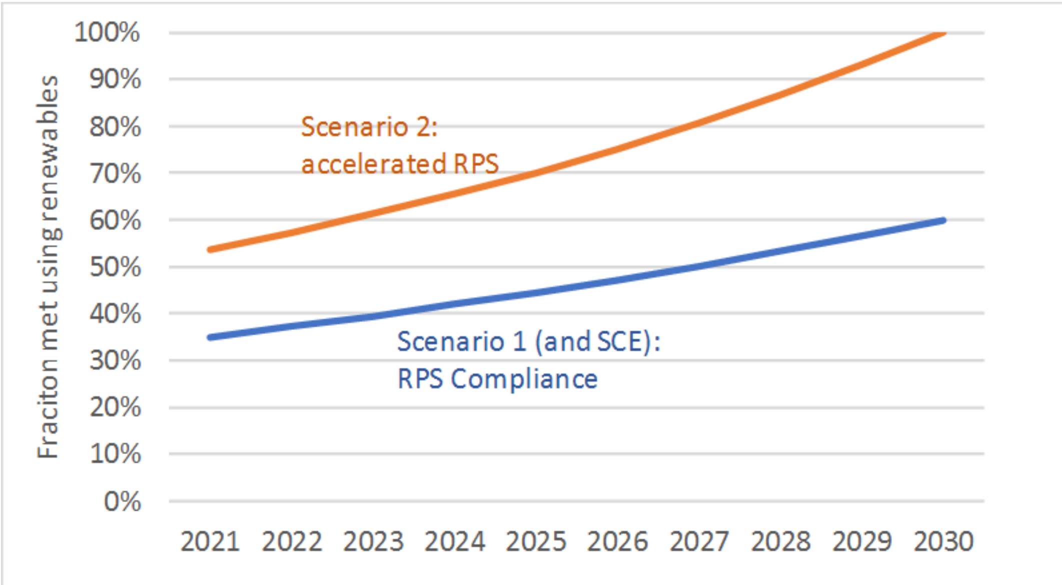
Supply Scenario 1, in which the CCA is assumed to meet, but not exceed California's Renewable Portfolio Standard (RSP) requirements and adds other non-GHG emitting resources so that the CCA's GHG emission rate is no greater than SCE's.

Supply Scenario 2, in which the CCA is assumed to start at 50% renewable power content and ramp up to 100% renewable power by 2030. (Figure ES-3).

In addition, two load scenarios for each supply scenario were considered: one in which all the potential CCA customers are served (but for 5% assumed opt-out rate) and one in which the TOU-8 subtransmission class is not served. [4] This latter case is modeled because based on the load data provided by many of the large industrial customers taking service on this tariff and SCE's rate structure, the CCA could not cost-effectively serve them.

[4] State law requires CCA to serve only residential customers; serving commercial, industrial or any other non-residential customers is optional.

Figure ES-3. Supply Scenario Renewable Content



Results

Figure ES-4 shows the Supply Scenario 1 forecast of average CCA 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 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.

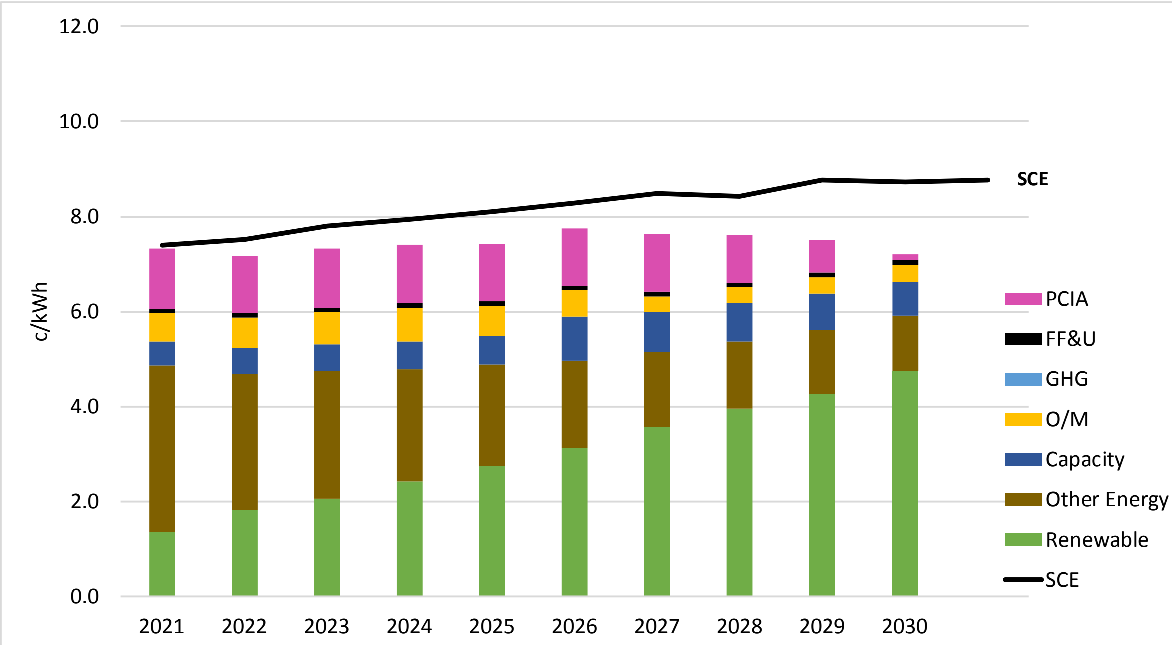
The bottom-most green segment represents the cost of renewable power to the CCA. The renewable power costs ramp up with increasing renewable content, as required by SB 100.

The brown segment is for the costs of non-renewable, wholesale market power. This segment slowly decreases, as renewable power increases.

The 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, even if the "intermittent" renewable resources are not generating at their optimal rate (e.g., solar on rainy days). The more intermittent renewables—solar and wind—that are added to the CCA's generating mix, the more back-up capacity is needed to ensure reliability.

The yellow segment is for operations and debt service. This segment reflects that from 2021 through 2024 the loans associated with the start-up costs are paid down ($40 million), remaining constant during this time period.[5] Once that debt is retired, the operations and debt service cost segment decreases markedly.

Figure ES-4. Supply Scenario 1 (serving all customers) Average CCA Cost Projection versus SCE Generation Rate



The narrow black segment is for franchise fees and uncollectibles. Franchise fees are those collected the SCE and paid to the City for the right to operate the electric monopoly franchise in the city.[6] Note that CCA formation does not change its franchise fee revenues; these are still fully collected and remitted by SCE as though the customers were still receiving SCE service. Second, as with any business, a certain fraction of the CCA's bills will not be paid and are treated as "uncollectible."

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.

[5] This analysis assumes a conservative (i.e., higher cost) start-up, wherein all startup costs and working capital are provided via a single loan. A more nuanced illustrative financial plan is shown in Chapter 5. Example of a Hypothetical 5-Year Cash Flow Analysis & Financial Strategy.
[6] See SCE Tariff Schedule FFS.

As shown in Figure ES-4, the costs of CCA operation in Supply Scenario 1 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:

- The CCA can keep its rates as the cost of operations and allow the margin to flow 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).
- The CCA can retain all or a portion of the margin to build up cash reserves for a rainy day.
- The CCA can use a portion of the margin to fund other energy-related services, such as providing incentives for customers to purchase an electric vehicle, install energy-efficient home upgrades, install solar panels, etc.

WHAT DOES A 0.5¢/KWH MARGIN MEAN?

If the CCA uses it to reduce rates, then the 0.5¢/kwh would reduce CCA customers' electric bills by ~3%. For a residential customer this translates to about $2.50 per month,

If the CCA retains the 0.5¢/kwh margin, it would generate about $15 million per year. If this was set aside, it would take from two to three years for the CCA to reach its reserve target 15% of annual revenues.

Note that this does not mean that the CCA can or will fully pass on this margin as rate savings to its customers. There are other uses that the CCA leadership may choose to use this margin for, most notably the generation of a rate reserve fund. Furthermore, other CCAs have chosen to use their margins for more generous solar PV programs, incremental energy efficiency, electric vehicle charging, or other programs that benefit the community.

Table ES-5 shows, on a dollar basis, the potential total margins available to the CCA under the Scenario 1 with no large industrial load being served. For perspective, the table also contains a column showing how much of the margin would be needed to offer a 5% discount off the average SCEs rates. As the table illustrates, a 5% rate savings could not be offered in the first year. In practice, in the first few years any rate savings would have to be balanced against funding of reserves.

Furthermore, the total margins would likely have to remain in the CCA (i.e., not transferred to the general fund) for rate reductions, CCA reserve accumulation, or CCA/energy-related projects.

Table ES-5. Scenario 1 CCA Margins ($millions per year), not including rate reduction or contributions to reserves

Year	Scenario 1 with Deferred Industrial Service	Cost of a 5%* Rate savings
2021	$7.3	$8.9
2022	$24.5	$18.8
2023	$28.8	$19.5
2024	$30.7	$19.8
2025	$39.7	$20.1
2026	$24.7	$20.5
2027	$32.6	$20.8
2028	$33.0	$20.6
2029	$45.6	$21.4
2030	$54.2	$21.2

Sensitivity Analysis

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 five variables with the greatest potential impact on the overall average cost of the CCA were investigated:

(1) 20% higher renewable supply costs

(2) 33% higher natural gas and power market prices

(3) 100% higher resource adequacy compliance costs

(4) 33% higher PCIA than forecast

(5) 5% lower SCE Rates

Other than the variable being tested, all other assumptions are from Scenario 1, not serving the TOU-8 subtransmission customers.

Table ES-3 provides some context for each case the table indicates if the CCA could (a) offer a 3% discount off its customers' total electric bills (i.e., both the CCA energy changes and the SCE delivery charges and PCIA); that same 3% discount and fully fund the CCA's reserve fund target by 2025; and (c) offer a 5% rates savings and fully fund the reserves. As the table shows, only in the base case—Scenario 1 serving all customers except TOU-8 subtransmission, could the last criteria be met. In all the others, a 5% rate savings could not be achieved.

Table ES-3. Sensitivity Cases Implications

Could the CCA:	Offer 3% rate savings? *	Offer 3% rate savings* and fully fund reserve by 2025?	Offer 5% rate savings and fully fund reserve by 2025?
Scenario 1	Yes	Yes	Yes
High Renewable Costs	Yes	Yes	No
High Market Prices	No	No	No
High RA Prices	Yes	No	No
High PCIA	Yes	Yes	No
Low SCE Rate	Yes	No	No

**Off Total bill (CCA generation and SCE charges), over each of the first 5 years.*

Risks and Risk Management

While commodity risk management within a competitive market is complex, it is well understood, and industry best-practice principles are known and followed from large investor-owned utilities down to small rural cooperatives and California CCAs. Supplying power to any aggregation of customers requires a diverse portfolio of energy products of various types and term lengths to be contracted for and actively managed as market conditions change over time. A "diversified portfolio" of energy products includes not just physical electricity products (energy, capacity, renewable certificates, emission reduction credits, ancillary services), but also physical fuel products (primarily natural gas, transportation and storage) as well as financial or insurance products (transmission congestion revenue rights, call/put options, etc.).

Sound CCA risk management must include:

1. A tightly-integrated front, middle and back office — providing a high degree of assurance that the CCA operates along established industry best-practices;
2. A comprehensive Energy Risk Management policy, along with the accompanying procedures and practices to ensure the Portfolio Manager is conforming to the CCA's risk policy;
3. The establishment of a Risk Management Committee, and full transparency in documenting all aspects of Energy Risk Management;
4. The practical ability to contract for and actively manage a diversified portfolio of not just electricity products, but also potentially fuel, financial and insurance products at launch;

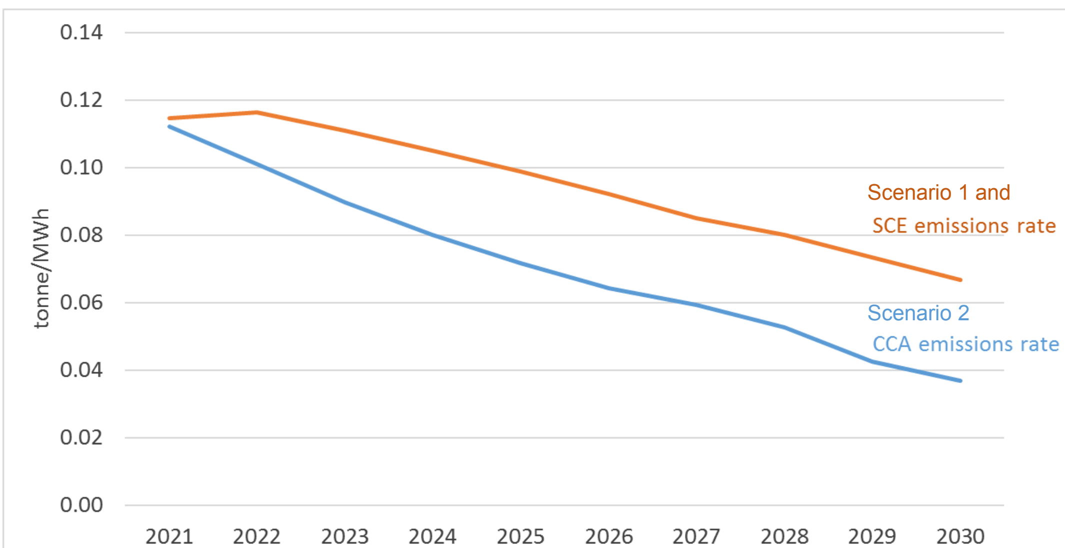
5. Active risk management in market operations (balance of month transactions, and day-ahead and real-time trading);

6. In general, the broad assurance that a variety of proven, industry-standard modeling, software, expertise and management/oversight procedures are being employed to protect the CCE's interests.

Greenhouse Gas Emissions

GHG savings are achieved when the average GHG emissions from the generation resources used by the CCA are less than the average GHG emissions from SCE. This requires the Long Beach CCA to either acquire power from large hydroelectric facilities (which are carbon-free but do not qualify as "renewable" under State law) at a price premium or dramatically increase the renewable content of the power beyond that required by the State. As the Figure ES-5 shows, the GHG emissions rate in Supply Scenario 1 matches—by design, SCE's average GHG emissions rate (orange line). This is accomplished by using hydropower, Figure ES-5 also shows the GHG emission rate under Supply Scenario 2: accelerated renewables (blue line). In this case, the CCA's GHG emission rate is consistently less than that of SCE's due to the portfolio's greater use of renewable resources.

Figure ES-5. Carbon Emission Rates



Macroeconomic and Job Impacts

A Long Beach CCA could potentially result in economic and employment benefits to the City and the region by offering lower rates, directly creating jobs, and causing local renewable energy and other projects to be built. The impacts are the result of four factors: *CCA administration and operation spending, net energy bill savings, development and operation of new renewable generation, and the resulting indirect and induced effects*. The first three effects can directly contribute to local business activity that leads to increased purchases from their suppliers of materials and services (referred to as "indirect effects"). It will also lead to re-spending of the additional worker wages on consumer purchases in the community (referred to as "induced effects"). The growth of any electricity generation or supplier purchases in adjacent areas can also have induced spillover effects as their workers spend additional money in Long Beach.

Over a 10-year time horizon (2021-2030), the CCA could potentially result in an increase in the gross regional product of $20 million per year and increase regional employment by approximately 185 jobs.[7] Eighty percent of these impacts are predicated on the assumed rate savings, which are uncertain, particularly in the latter years when the greater impacts occur. Thus, they should be seen as a general metric of the potential rather than predictive.

Governance and Implementation Options

If it is to pursue CCA, Long Beach will have to decide between two primary governance options for the CCA: a city-only CCA or joining a Joint Powers Authority (JPA) such as the Clean Power Alliance (CPA).

In a city-only 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 and based upon the City's 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, formulation of financial and debt policies. 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.

On the JPA side, Long Beach may be able to become a member of the CPA, the CCA that serves unincorporated Los Angeles and Ventura Counties along with 29 municipalities within those counties. CPA is governed by a board of directors with one voting member per jurisdiction. Votes are tallied on an equal basis, one vote per jurisdiction, no matter its size. After an affirmative vote, three directors may call for a vote based on load share. In that case, 50% of the weighted voted share would be needed to carry the item.[8] The primary benefits of joining CPA are the security and reduced risk of joining with an already-operating entity and reduced administrative burden on City Staff, both in CCA formation and in ongoing management. The tradeoffs to joining 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 importance of support programs.

[7] Based on Scenario 1 with the CCA not serving the TOU-8 subtrnasmission class and ½ of the net margin in each year goes to rate reduction.
[8] JPA agreement, section 4.10.3

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 taking their power from 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 is 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.

Per California law, when a CCA is formed all residential the electric customers within its boundaries will be placed, by default, onto CCA service. (the CCA may elect to serve non-residential customers, but ins only obligated by law to do so). 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 Long Beach's CCA 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 Long Beach.

Rate Competitiveness and Financial Stability

A City of Long Beach CCA would expect to offer rates that are competitive with those offered by the incumbent electric utility, Southern California Edison (SCE). If they could not, the CCA would be formed. "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 each and every year a specific rate savings is offered. In fact, some early CCAs had to offer rates slightly higher than 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, and it is operated 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 Climate Action Plan Objectives

The City of Long Beach is developing its first-ever Climate Action and Adaptation Plan (CAAP), which will, among other things, provide a guide to the city as it reduces greenhouse gas (GHG) emissions. As discussed later, a CCA, if is it financially able and so chooses, can contribute to the City meeting its CAAP objectives.

It must be noted that California is also moving toward a similar 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 CAAP 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 CAAP are non-negotiable objectives, a CCA can also serve as a vehicle to pursue other objectives that benefit the City, its residents and businesses. Example-s of additional objectives could include the following.

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 to 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 how provides their power, the rate comparisons here focus on the CCA rate (plus the PCIA charge) versus SCE's generation rate.

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 the 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 incent 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 to better reflect its community's interests and values than an investor-owned utility like SCE can. This is illustrated in the CCA's objective of supporting the City's CAAP. However, it may go beyond this; the CCA may choose to commit to providing opportunities for citizens to provide input into its programs and policies, such as having a citizens' advisory board or having a non-voting at-large community seat on the CCA's board of directors.

Assessing CCA Feasibility

In order to assess whether a CCA is "feasible" in Long Beach, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the City, this study:

- Quantifies the electric loads that an Long Beach CCA would have to serve.

POWER PRIMER

The California Independent System Operator (CAISO) manages the balance between electricity load and supply on its system. 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 forecast.

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 energy usage (kWh) and peak demand (kW) requirements of its customers.

- Estimates the costs to start-up and operate the CCA.
- Considers two scenarios with differing assumptions concerning the amount of carbon-free power being supplied to the CCA so as to assess the costs and greenhouse gas emissions reductions possible with the CCA.
- Includes analysis of in-city renewable generation.
- Compares the rates that could be offered by the CCA to SCE's rates.
- Quantitatively explores the rate competitiveness of scenarios to key input variables.
- Discuses, and where possible, quantifies the risks to the City and its residents and businesses of CCA formation.
- Calculates the macroeconomic development and employment benefits of CCA formation.

Reaching CCA Objectives

Financial

As noted above, a City of Long Beach CCA 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 to the CCA so all liabilities are covered and it is overaged 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 a Long Beach CCA would be a financially independent enterprise with no funds or debts comingling with the City 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. As a part of the City, the CCA will be able to utilize the expertise and systems of the City to reduce overhead costs.

Climate Change Mitigation

As noted above, the City is developing its first ever CAAP. According to the Draft CAAP, the mission for the plan is to:

- Create an inclusive, community-centered planning process to engage the Long Beach community broadly and with attention to those most affected by climate change, including low income and people of color, youth and older adults.
- Communicate climate change impacts in Long Beach by meeting residents and community members where they already gather, such as community events, cultural festivals, senior centers, schools, etc.
- Build capacity to co-define solutions and priorities to inform the CAAP.

- Collaborate with internal (City departments) and external stakeholders (community members, business community, neighborhood associations, scientific community, etc.).
- Commit to ensure the Long Beach community and physical assets are better protected from the impacts of climate change.[9]

The Draft CAAP would set a GHG reduction target for 2030: The City's 2030 target is established on a per capita emissions basis and aims to achieve emissions rates of 4.46 metric ton (MT) CO2e per capita, or 3.06 MT/service population. This compares to the city's 2030 business-as-usual forecast of 6.5 MT CO2e/capita.[10] The City has set an aspirational goal to achieve net carbon neutrality citywide by 2045, which is consistent with the state's Executive Order B-55-18 that calls for statewide net carbon neutrality in the same year. With no CAAP, under the business-as-usual emissions forecast scenario the City's 2045 emissions are estimated to be approximately 2.6 million MT CO2e.[11]

To the extent which the carbon content of the power provided by the CCA is lower than that provided by SCE, the CCA can contribute to meeting the CAAP's 2030 goal and 2045 aspiration.

Renewables – what does it mean to be 100% Green?

Most CCAs offer "100% Green" rate options; 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 Regional Community Choice Energy Authority 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 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 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 longer 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,

[9] Long Beach Development Services, *City of Long Beach Climate Action and Adaption Plan*, May, 31, 2019. Public Review Draft.
http://longbeach.gov/globalassets/lbds/media-library/documents/planning/caap/caap-introduction-community-context--climate-science-overview--draft-released-05312019-logos
[10] Ibid.
[11] Ibid.

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 active CCAs in California currently offer rates that are at or lower than their incumbent utility, be it SCE, Pacific Gas & Electric or San Diego Gas & Electric. 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 the Inland Empire and other hotter areas of Southern California, 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. By not having as much air conditioning load in Long Beach than the rest of the SCE territory on average, a Long Beach CCA would have a structural advantage as they would not have to purchase as much power at the highest priced times.

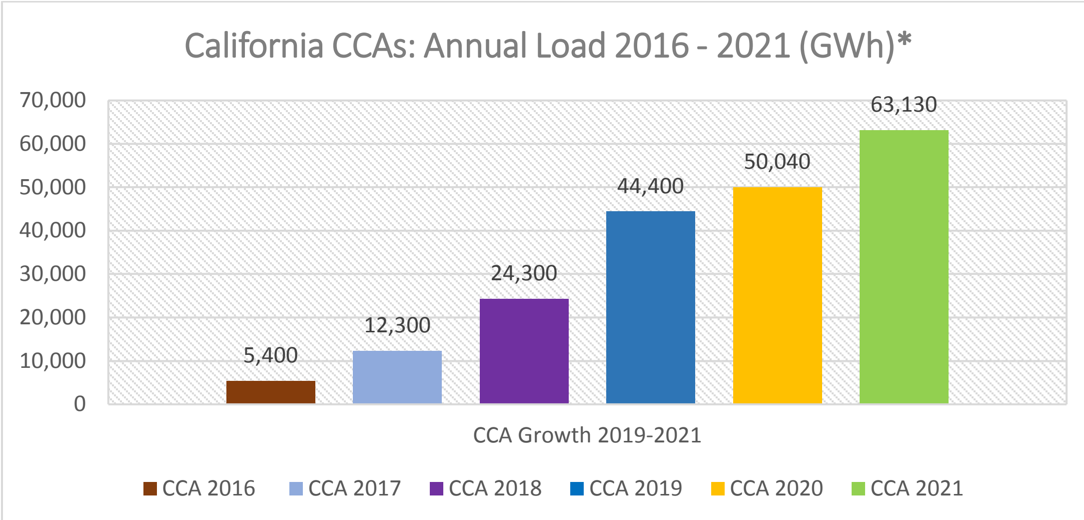
Second, all CCAs are taking advantage of the fact that the incumbent utilities have in their portfolios some relatively expensive, generally renewable, power purchase contracts. This raises the utilities' rates, but also begs the question of what happens when those contracts expire. Two things happen. First the Power Change Indifference Amount (PCIA) fee is reduced, because it is 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 cumbersome vetting process and must be approved by the full CPUC. Further, 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. CCAs 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), didn't 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[12]



*Figures for 2020/2021 are projections based on expected launches

Table 2 lists the active CCAs in California, including those which have announced intended launches in 2020 and 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 will come from new CCAs in SCE's territory. Currently there is only one small CCA in SDG&E's territory, Solana Energy Alliance, but a large JPA in the San Diego region is 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 two stand-alone city CCA enterprises, San Francisco and San Jose, both of whom serve total loads that would be very similar to the size of a Long Beach CCA but are in PG&E's service area. If formed, a Long Beach CCA would be the only stand-alone municipal CCA in SCE's service area.

Table 2. CCAs in California

CCA	IOU	Type	Formed	Load, GWh[13]
CCAs 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
Monterey Bay Community Power	PG&E	JPA	March 2018	3,202

[12] Figure courtesy of Cal-CCA.
[13] 2019 Load (GWh) reported by CalCCA: https://cal-cca.org/cca-impact/

CCA	IOU	Type	Formed	Load, GWh[13]
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
Solana Energy Alliance	SDG&E	City	June 2018	37
Planned Launch				
Desert Community Energy	SCE	JPA	2020	1,668
Western Community Energy	SCE	JPA	2020	1,575
Baldwin Park	SCE	City; CCEA	2020	255
Pomona	SCE	City; CCEA	2020	655
Palmdale	SCE	City; CCEA	2020	655
Hanford	SCE	City; CCEA	2020	285
Commerce	SCE	City; CCEA	2021	460
Drafted ordinances for implementation as soon as 2021				
San Diego Regional CCE Authority	SDG&E	JPA	2021	6,800
North SD County CCA	SDG&E	JPA	2021	2,750
Butte County	PG&E	JPA	2021	1,080
City of Santa Barbara	SCE	City; CCEA	2021	TBD

Figure 2. California Active CCA Loads (Annual GWhs)

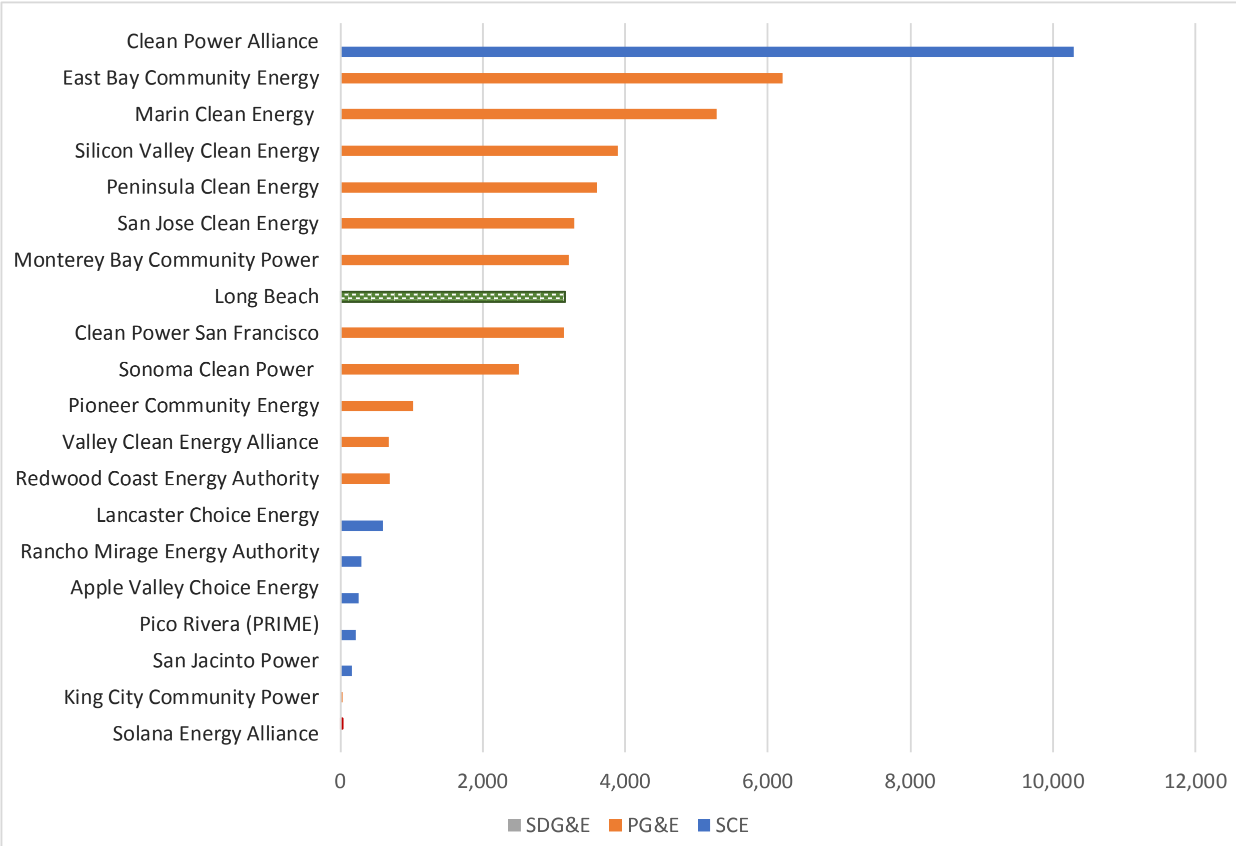


Figure 2 shows the 2019 annual loads of the active California CCAs. Three observations can be made from this figure. First, Clean Power Authority (CPA), the CCA that serves Los Angeles and Ventura counties along with selected communities therein, is large—nearly twice the size of the second largest CCA, East Bay Community Energy. Second, were Long Beach to form its own CCA, it would be moderately sized relative to all the CCAs, indicating that economies of scale would have been reached. Third, a Long Beach CCA would be the second largest in the SCE territory, as all SCE CCAs beyond CPA are small cities that are members of CCEA.

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 program funding from the CPUC.[14] 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, then the CCA will receive money that is collected in IOU rates through the Public Purpose Program rate element. Another example of this second phase of CCA evolution is offering rooftop solar programs and feed-in-tariffs for local renewable generation projects that connect "in front of" the customer meter. A third example is installing additional EV charging stations and encouraging EV purchasing and leasing.

The third phase in evolution observed with California CCAs is moving 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.

Table 3, 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, the speakers, panels and presentations overwhelmingly focused on innovation that CCAs can do and are doing.[15] None addressed power procurement or cost competitiveness.

[14] 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.
[15] https://theclimatecenter.org/the-business-of-local-energy-symposium-2019-presentations/

Table 3. Sample California CCA Program Offerings

Range of CCA Customer Programs

	CleanPowerSF	Lancaster Choice Energy	Peninsula Clean Energy	MCE	Sonoma Clean Power	Apple Valley	East Bay Community Energy	Silicon Valley Clean Energy	Pioneer	PRIME	RCEA	Solana Energy Alliance	MBCP	Clean Power Alliance	San Jose Community Energy
Budget Billing	In dev.				In dev.						In dev.				
Battery Storage Rate															
Customer Load Shifting															
Demand Response			In dev.	In dev.			In dev.								
EV Rate															2019
EV Bus Program															
EV Incentives		In dev.	In dev.										In dev.		2019-20
EV Load Shifting															
Energy Efficiency		In dev.								In dev.					
Low-Income & Multifamily EE															
Feed-In Tariff	In dev.										In dev.		In dev.		
Fuel Switching								In dev.					In dev.		2019-20
Low Income Solar Incentives			In dev.				2019								
Net Energy Metering							2019								2019
On Bill Repayment	In dev.				In dev.										
Community Outreach Grants															
Community Energy Grants			In dev.												
PACE Program															

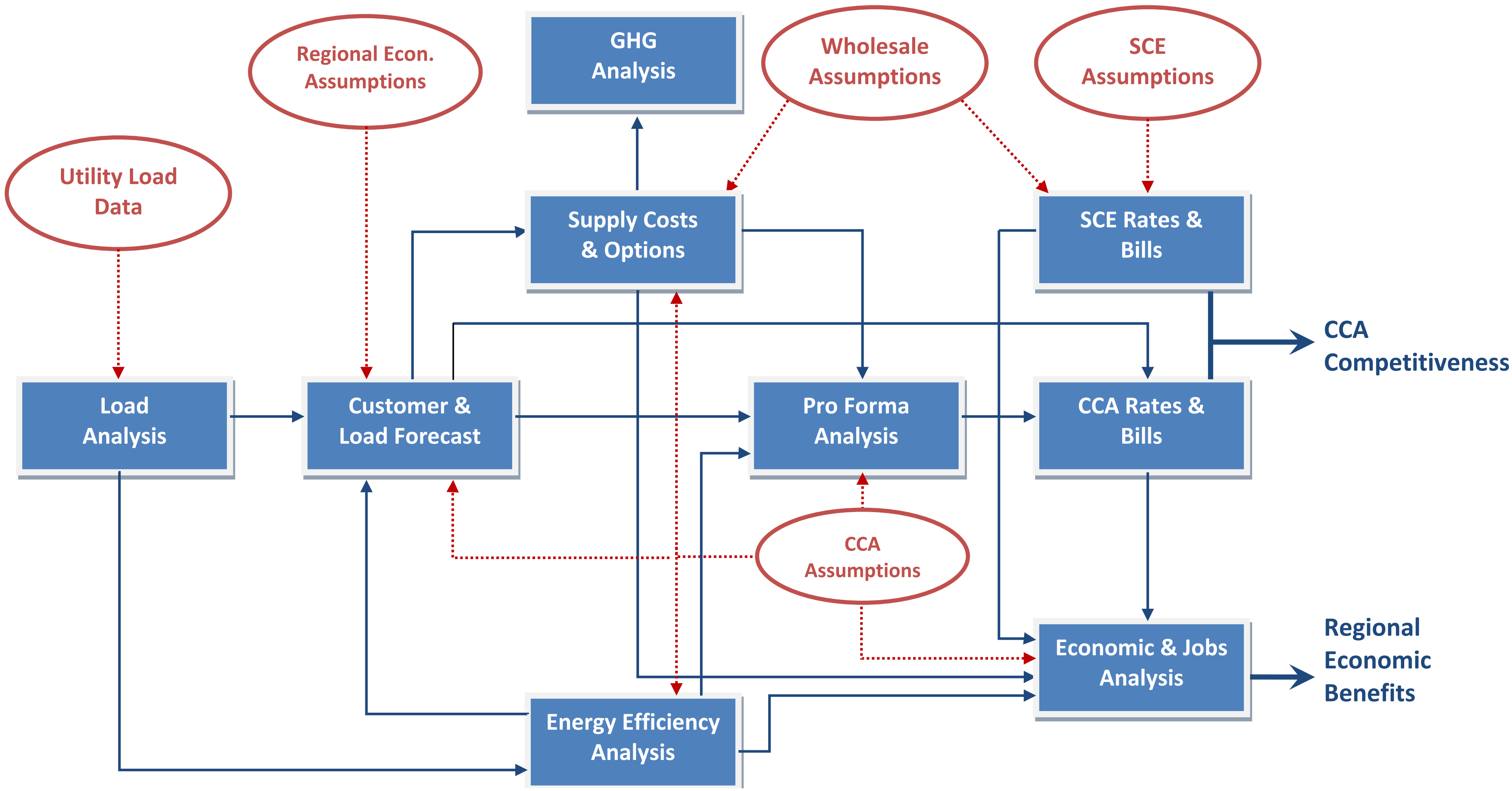
Chapter 2. Economic Study Methodology and Key Inputs

This chapter summarizes the key inputs and methodologies used to evaluate the cost-effectiveness and cost-competitiveness of a Long Beach CCA relative to SCE under different scenarios. It considers the regulatory requirements that a Long Beach CCA 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.

Understanding the interrelationships of all the tasks and using consistent and coherent assumptions throughout are critical to developing a meaningful analysis. Figure 3 shows the analysis elements (blue boxes) and major assumptions (red ovals) and how they relate to each other. As the figure illustrates, there are numerous interrelationships between the tasks. For example, the load forecast is a function of not only the load analysis, but also of projections of economic activity in the City.

An important point is highlighted in this figure 4: it is critical that wholesale power market assumptions are consistent between the CCA and SCE. While there are reasons that one might have lower or higher costs than the other for a particular product (e.g., CCAs can use tax-free debt to finance generation projects while SCE cannot), both will participate in the wider Western U.S. gas and power markets and therefore will be subject to the same underlying market forces. Applying different power cost assumptions to the CCA than to SCE, such as simply escalating SCE rates while deriving the CCA rates using a bottom-up approach, would produce erroneous results.

Figure 3. Task Map



Long 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; industry-standard methodologies for load forecasting will be used to provide the foundation of future procurement.

Because a Long Beach CCA is still hypothetical and has yet to sign up, let alone serve, any customers, the amount of energy that CCA customers is based on historical consumption data from SCE. Of course, if the CCA moves forward the forecast will be continually updated and refined to reflect ongoing economic development in the City, changes in load from energy efficiency and distributed generation.

As shown in Table 4, the City's total annual electric load, not including DA,[16] is about 3.1 GWhs, or 3% of SCE's total load. This load is spread across almost 180,000 accounts. As shown in both the table and in Figure 4, a very large portion of the load, over 40%, is from the large commercial and industrial class.[17] This is unusual; most other CCAs have only modest at best large commercial and loads. The importance of this fact is discussed later in this report.

Table 4. Potential Long Beach CCA Customers and Associated Load

	Customers	Annual Load (MWh)
Residential	158,480	746,292
Small Commercial	16,512	591,646
Medium Commercial	2,638	456,615
Large Commercial & Industrial		
On TOU-8 Sub-transmission	*28*	*853,323*
On other Tariffs	*78*	*366,780*
Total Large C & I	106	1,220,104
Other*	1,967	67,636
Total	**179,703**	**3,082,293**

*streetlights, traffic control, agriculture/pumping.

[16] The amount of DA service allowed in SCE's service area is capped by law. Due to existing contracts with their ESPs, DA customers are not likely to join a CCA. Thus, the pool of possible CCA customers is limited to those currently served by SCE.

[17] More specifically, from SCE Rate Schedules TOU-8 (Primary) and TOU-8 (Sub-transmission)

Figure 4. Long Beach Load Distribution

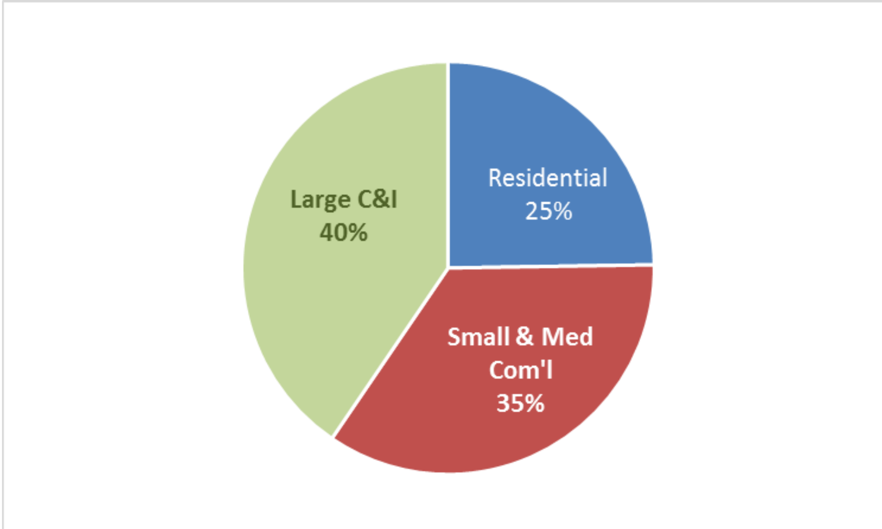
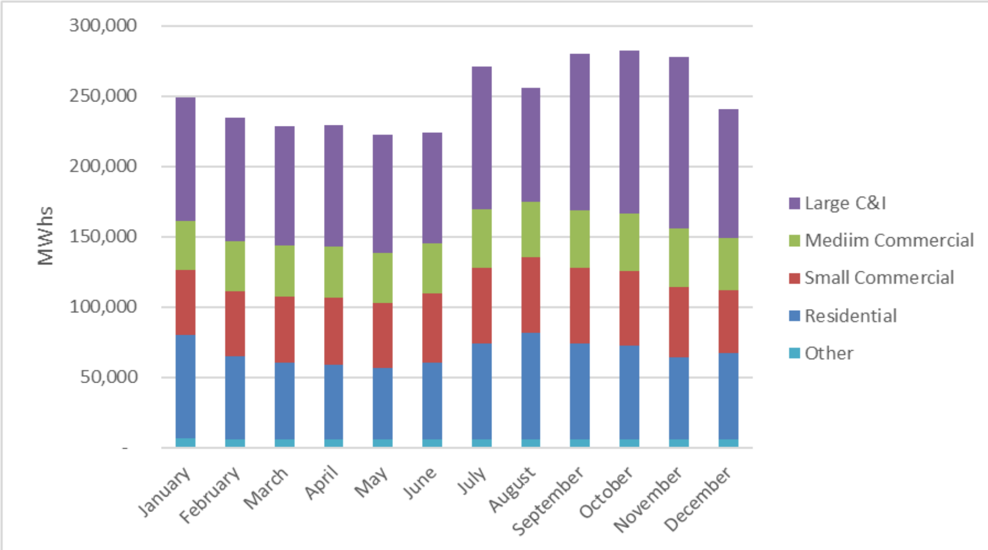


Figure 5, below shows the potential monthly load for the Long Beach CCA. The highest load months are in the late summer and fall, while the lowest are in the spring. Also note that the highest month is only about 25% higher than the lowest month. This is attributable to Long Beach's coastal climate. In hotter inland areas, where air conditioning is more common, the differential between the highest and lowest month is more pronounced.[18] This provides a benefit to Long Beach, as it does not have to acquire as much "resource adequacy" capacity as it would were it located away from the Pacific.

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 each rate classes' total load into hourly consumption values. SCE provided the monthly usage by rate class, but it did not provide the hourly load profile. For the residential and small commercial classes, the load profile is based on profiles provided by the Clean Power Alliance, the CCA serving Los Angeles and Ventura Counties. For the medium and large commercial and industrial classes (i.e., customers taking service on rate Schedule TOU-8), we relied upon the published SCE dynamic load profiles.

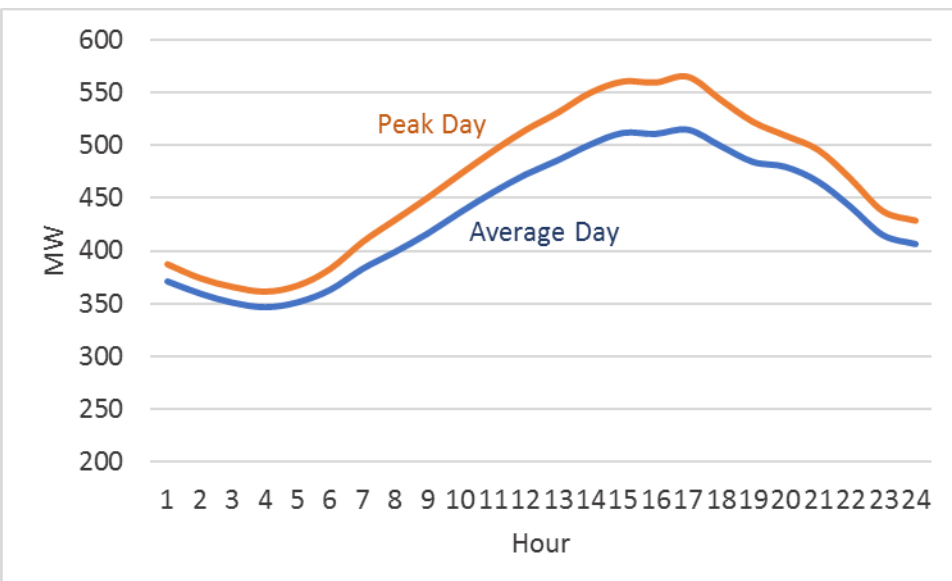
[18] The ratio of the usage in the highest-load month to the lowest-load month for Long Beach is 1.3; for the City of Riverside, a municipal utility, the ratio of the highest-load month to the lowest-load month is 1.7. (City of Riverside Public Utilities, 2018 Integrated Resource Plan, September 26, 2018. page 2-2.)

Figure 5. Long Beach CCA Load (Monthly, 2020)



Based on these data, Figure 6 below illustrates the 24-hour load curve averaged across all days in September and the day with the highest load. The top of the orange line reflects the maximum capacity need for the CCA and is the basis for the CCA's resource adequacy requirement in September.

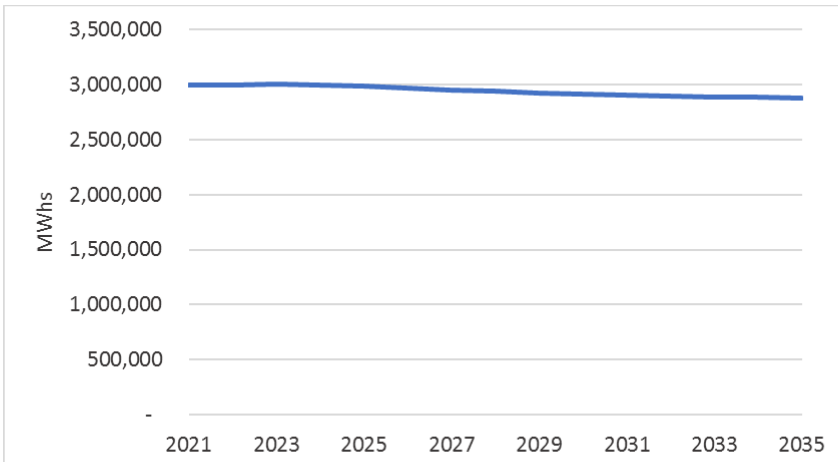
Figure 6. Long Beach CCA Load Shape (September)



Forecasting

The CCA's base load forecast through 2030 reflects the annual average growth rate from the California Energy Commission's most recent electricity demand forecast for SCE's planning area. This growth rate incorporates load reductions from energy efficiency programs and expected behind the meter distributed generation (e.g., rooftop solar). As Figure 7 shows, the CCA's load is forecast to be relatively flat for the first few years and then slightly decline. The Net growth rate from 2021to 2035 is negative 0.3% per year.

Figure 7. CCA Load Annual Forecast



Large Customer Significance

Having large commercial and industrial loads account for a large fraction of the CCA's potential load carries with it several important implications. First, a single "opt-out" of one of these customers, be it during the initial roll-out or after CCA service has commenced, can have a marked impact on the CCA's supply-load balance. This must be accounted for with constant and open communications with the larger customers and a procurement risk management plan that accounts for this possibility. Second, given the SCE rate structure, the "cost to serve" these customers (that is, the cost of providing them power and accounting for the overhead burden they place on the CCA) can exceed the rate revenue that they bring in. In other words, even if the CCA offers only a $1 savings to a TOU-8 subtransmission customer relative to their taking SCE service, the CCA could spend more on serving that customer than they receive in rate revenue. This is a perverse result of the ratemaking process at the CPUC, which sets rates based on "marginal costs" rather than the full actual costs to serve. While there is sound economic theory behind this ratemaking approach, it creates difficulties for CCAs (and DA electricity service providers) who are trying to offer price-competitive service to larger customers in SCE's territory.

Knowing this, City staff and MRW team member ZGlobal reached out to the largest electricity consumers in Long Beach to (a) understand their interest in CCAs and priorities with respect to power (e.g., low cost versus lower carbon content) and (b) get permission to use their specific load data in the analysis. Enough data were gathered to separately and explicitly account for a significant fraction of the large customer base in the analysis. Based on this data and the SCE rates, the MRW Team chose to include scenarios where the customers on the TOU-8 subtransmission tariff were not included in the CCA.

Phasing in the CCA's Load

All the scenarios assume a simple phase-in schedule for the CCA:

1. City accounts to begin service in March 2021
2. Large commercial customers in June 2021
3. Residential and small commercial accounts to being service on or about October 2021

There are three reasons to phase-in the CCA's load. First, there are significant logistical back-office activities that must occur: loads must be forecast on a daily basis for scheduling into the CAISO; daily meter data must be exchanged between SCE and the CCA; the CCA must calculate its customers' bills based on SCE data and return the billing amounts to SCE for presentation. While the providers of these services are becoming more familiar with the various protocols, it is simpler to begin serving only a small number of customers—often the municipal and government accounts—so as to work out the metaphorical kinks on less sensitive accounts before rolling out to the general public.

Second, CCAs phase in their load for economic reasons. For example 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. Thus, if the CCA is properly hedged, it can be advantageous to phase in the commercial loads in the summer to take advantage of the higher margins.

Third, since the CCA's rates will, at least initially, be tied to SCEs, 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 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.

CCA Power Supplies

The cost to provide power is by far the largest expenditure a CCA makes. A CCA the size of Long Beach should expect to spend approximately $100-140 million per year for wholesale power.[19] The Long Beach CCA power supply plan will be guided by legislative requirements, regulatory mandates and CCA policies, as well as future market dynamics.

[19] High value assumes service to all customers (net 5% opt-out). Low value assumes service to all customers except those of SCE Schedule TOU-8 sub-transmission (again net 5% opt-out).

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 Power. 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.[20] 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 a Long Beach CCA will be. Unless the Long Beach CCA 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 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 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

[20] 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.

3) **Flexible** capacity requirements to meet the largest continuous three-hour load increase ("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 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.

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 to meet a 1-in-10 weather year peak and an N-1-1 contingency (e.g., the sequential loss of two transmission elements). Beginning with the 2020 compliance year,[21] the Local RA requirements are set three years ahead and updated each year. LSEs are required in their annual filings to show that they meet 100% of local requirements for the next two years and 50% of the third-year requirement.[22]

The CAISO also determines the required Flexible RA needs and 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 LSEs must demonstrate purchase of 90% of their flexible RA requirement in their annual RA filing, and 100% of the requirement in their monthly RA filings.[23]

There is a bilateral market for RA capacity, with standardized products for system, local and flexible RA capacity. The RA mandates can also be met through RPS contracts, as well as with resources that are contracted under tolling agreements that provide both capacity and dispatchable energy. Non-dispatchable renewable resources are assigned net qualifying capacity based on their effective load-carrying capacity (ELCC) during RA "measurement hours" (currently hours ending 17-21, or 4:00 p.m. - 9:00 p.m.).

An LSE may apply certain "credits" toward meeting its RA requirements that it may receive as a result of capacity purchases made by the IOUs or CAISO:

- Dispatchable DR programs administered by IOUs but available to all customers in the utility service territory;

[21] 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.
[22] 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.
[23] 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.

- Cost Allocation Mechanism (CAM) capacity that IOUs procure on behalf of all customers and for which all customers are charged;
- Behind-the-meter generation directed by CPUC and procured by the IOU on behalf of all customers;
- Reliability Must-Run (RMR) capacity designated by CAISO to meet local capacity needs; and
- Capacity Procurement Mechanism (CPM) capacity procured by CAISO to resolve collective (or individual LSE) capacity deficiencies.

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). On November 7, 2019 the CPUC issued a decision addressing the potential for system resource adequacy shortages in SCE's transmission access area due to the impending retirement of approximately 3,750 MW of once-through cooled (OTC) power plants as well as the risk of additional non-OTC retirements. The decision calls on the State Water Resources Control Board to extend OTC compliance deadlines by three years for at least 2,500 MW and up to 3,750 MW of affected capacity. The decision requires LSE's in SCE's transmission access area to purchase a *pro-rata* share of 3,300 MW of new or existing capacity through an all-source solicitation. The procurement will be "all-source," meaning that it includes both supply- and demand-side resources. There is a phase-in of the requirement, with at least 60 percent delivered by August 1, 2021, 80 percent by August 1, 2022, and 100 percent by August 1, 2023.

Additional Potential Requirements. In a separate rulemaking (R.17-09-020), the CPUC is also considering the development of a "Central Procurement Entity" (CPE) to take over RA procurement for a portion of the overall requirement, or potentially the entire RA requirement, for LSEs under CPUC jurisdiction. The CPE could be a public benefit corporation, new state agency, the IOUs, or some other entity (e.g., the CAISO). The CPUC has previously indicated that it believes a CPE is in the best interests of the State and electric customers. If such an approach were to be implemented, there would need to be an allocation of procurement costs and credits among the various LSEs. Workshops have been held to discuss these issues among stakeholders and on August 30, 2019, a group of generators, CalCCA, and SDG&E put forth a comprehensive plan to implement a CPE that would procure "residual" RA requirements for all LSEs. This would allow LSEs to take full advantage of existing RA agreements and to have the CPE only procure for the RA requirements not met by LSEs' existing RA contracts and resources. The proposed CPE would take effect no sooner than 2022 compliance year. Note that neither SCE, PG&E, or any ESPs have signaled support for this proposed plan.

In another rulemaking (R.17-06-026), parties are trying to develop an approach whereby IOUs would be forced to divest their excess resources to other LSEs in the market. One approach that is being considered is to have a mandatory allocation of Local RA resources amongst all LSEs (i.e., IOUs, CCAs, and ESPs) in individual TAC areas and to have a voluntary allocation of the IOU's excess System and Flex RA as well as RPS and GHG-free resources. In the case of

System and Flex RA and RPS and GHG resources, if LSEs do not choose to voluntarily accept the offered allocations, then the IOU would auction off the non-allocated resources (thereby reducing above-market costs). If certain resources were not selected in the voluntary auctions, then the above-market costs of those resources would be included in the PCIA.[24] This proposal is just being developed by the co-leads assigned to this topic and no decision by the CPUC on this issue would occur before the middle of 2020. However, if a system of this type were adopted by the CPUC, it could simplify procurement of RA for newly formed CCAs.

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 Long 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 60% 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 ZGlobal. Likewise, resource adequacy requirements are estimated based on peak loads and after accounting for net qualifying capacity from renewable resources (based on ELCC estimates) and CAM credits. The remaining capacity need is assumed to be purchased at a forecasted market price as described below.

Renewable

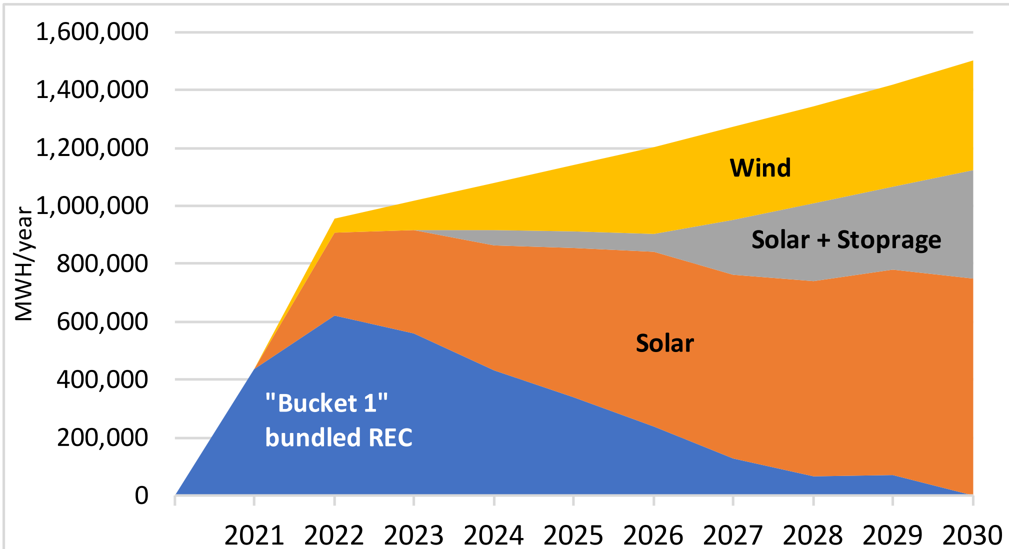
The cost of renewable energy from solar photovoltaic (PV) facilities has steadily fallen since the establishment of the California RPS mandate in 2002. Looking forward, solar PV prices are expected to continue to decline, although at a slower rate as the technology matures and if import tariffs continue 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 overgeneration. Thus, there are advantages to a diversified supply portfolio including wind, geothermal and biomass, as well as energy storage.

Figure 9 below shows the assumed mix of renewable resources in Supply Scenario 1: meeting but not exceeding the State's renewable portfolio requirement, e.g., 37% in 2021, 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, (i.e., "Bucket 1" renewable energy credits). 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

[24] A system of this type is used for allocating excess pipeline capacity for core gas customers.

balance of renewable resources: wind and solar are generally complementary in California—that is, when solar output is high, wind output is low.

Figure 8. Renewable Power Generation by Source (Supply Scenario 1)



Assumed renewable power prices are shown in Figure 10. The 2021 prices are consistent with current reported renewable contract prices from other California CCAs and municipal utilities. For future solar prices we relied on the DOE's Solar Energy Technologies Office SunShot 2030 goals for levelized cost of energy, which show modest declines in constant dollars.[25] When converted to nominal dollars there is a slight upward trend, which we continue through the period of analysis. Solar combined with 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 storage, we assume projects are likely to be commercial scale (i.e., large rooftop), so we relied on the SunShot 2030 goals for Commercial PV, which show significant declines from 2020 costs. We do not expect commercial PV costs to cross over and become less expensive than utility-scale solar, so we therefore did not continue the Commercial PV price trend past 2030, but rather assumed the real dollar cost declines end and that the prices increase with inflation after 2030.

For wind prices we relied on the DOE's Wind Vision report to establish a forecasted price for 2030 and continued the price trend for subsequent years.[26]

"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 $19/MWh, remaining level in nominal dollars.

Alternative renewable costs are explored in the sensitivity scenarios.

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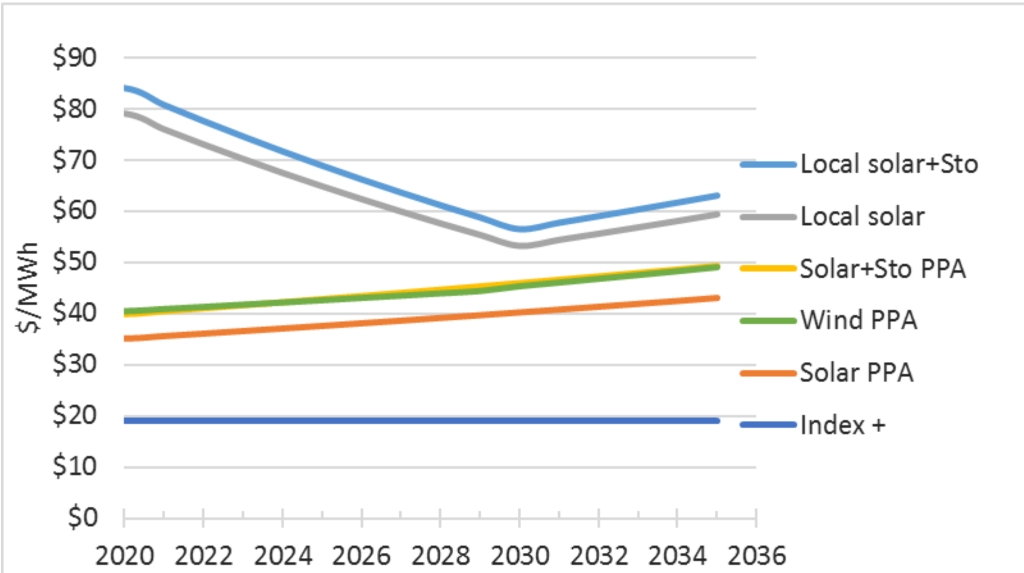
[25] https://www.energy.gov/eere/solar/sunshot-2030
[26] https://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf, Figure 3-12.

Figure 9. 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, ZGlobal performed detailed production cost simulation modeling of California and the western grid. ZGlobal used the PLEXOS production cost model to derive hourly market prices for energy and ancillary services. PLEXOS Integrated Energy Model[27] is a commercial optimization engine that can simulate the economic commitment and dispatch used by the California ISO's (CAISO) day-ahead market processes which simultaneously optimizes energy dispatch and ancillary services capacity awards across the ISO grid. In this way, the simulation will determine locational marginal prices and ancillary service marginal prices in the same manner the ISO day-ahead market sets prices. ZGlobal developed models for 2021 and 2030 using input assumptions that are based on common case inputs and planning guidelines from WECC, CAISO, CPUC and CEC. The key assumptions considered for the assessment included the impact of higher California renewable energy standards (50% RPS by 2030), planned gas-fired and nuclear generation retirements and adopted California Energy Commission (CEC) demand forecasts which consider energy efficiency programs and increased behind-the-meter solar generation.

Market prices or locational marginal prices (LMPs) for the City of Long Beach are based on the Southern California Edison (SCE) aggregated load prices which the ISO establishes for each

[27] http://energyexemplar.com/software/plexos-desktop-edition/

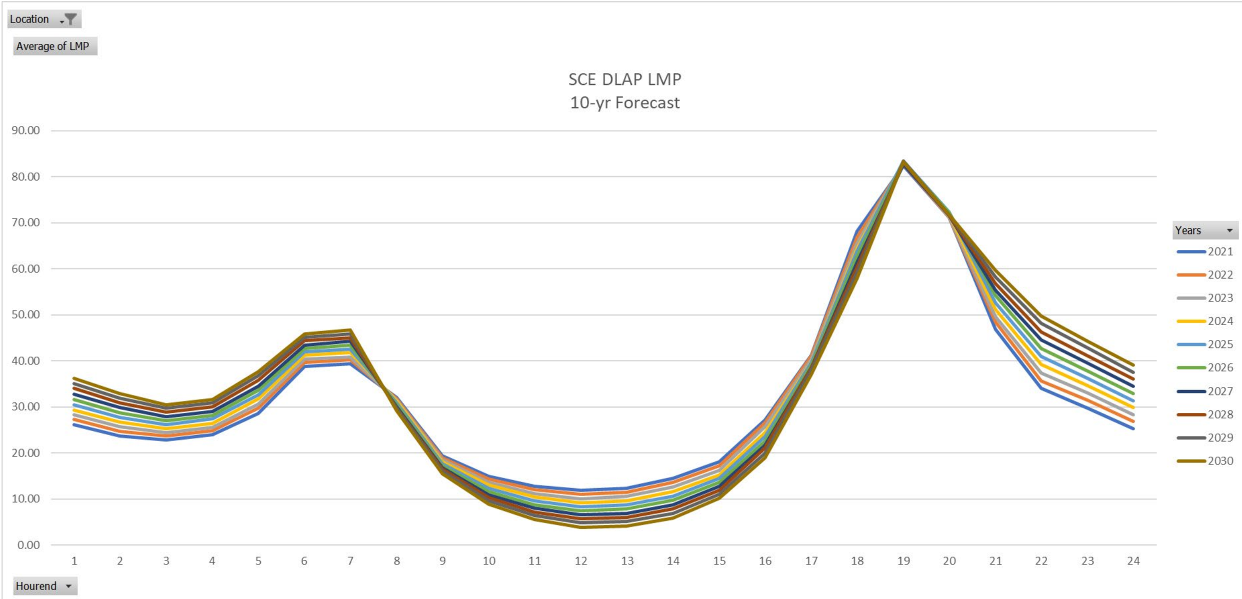
hour of the day for day-ahead and real-time markets. ZGlobal's study produces a 10-year forecast of the CAISO market pricing based on the 2 study years simulated in the production cost modeling and then interpolating for the intermediate years. Such modeling considers detailed loads and generation resources, as well as transmission constraints, to determine the hourly market clearing resources and their operating costs, as well as estimated losses and congestion prices for specific pricing nodes, including those serving Long Beach. The resulting prices reflect the market from which a Long Beach CCA would make wholesale purchases, which includes the cost of complying with California's cap-and-trade regulation of CO_2 emissions.

Figure 11 shows the average hourly price comparison of the 10-year price forecast. In real terms, there is little difference in the peak LMP prices among years. However, as increased renewables are built over the 10-year periods, the mid-day prices during high solar hours are anticipated to get more depressed.

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 ZGlobal 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 11 presents the average hourly shape of forecasted market clearing prices for power delivered to SCE's load aggregation point over a 10-year period. Price data for individual months or days demonstrate even greater variation across the hours of a day.

To estimate wholesale power costs for each hour, we began with the forecast of CCA loads for that hour and subtracted generation from RPS resources (excluding Index + supplies since the energy is ultimately provided through market purchases). Generation shapes were provided by ZGlobal and reflect CAISO system average hourly deliveries by resource type. Thus, we are assuming solar and wind resources are sourced from across the CAISO system rather than a particular location. More detailed portfolio analysis, such as during RFP bid evaluation, would need to account for specific project delivery profiles. The resulting net short quantity for each hour is then multiplied by the forecasted market price for that hour and summed across the months and years to estimate wholesale power costs for each time period.

Figure 10. ZGlobal Forecast of Market Prices (2021-2030)



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. The CPUC's 2018 Resource Adequacy Report shows weighted average System RA prices for the 2018 through 2022 compliance years ranging from \$2.65/kW-month to \$3.25/kW-month. Even at the 85th percentile, prices are only slightly higher at \$3.33/kW-month to \$4.25/kW-month.[28] Local RA prices for the LA Basin are slightly higher than System RA prices, averaging \$4.25/kW-month for the 2018-2022 period compared to \$3.75/kW-month for System RA capacity.

A September 2019 report from the CPUC Energy Division on "The State of the Resource Adequacy Market" confirmed that there are currently excess RA resources in the market, but pointed to an overall tightening of future supply due to coastal power plant retirements and reductions in solar capacity values.[29] As discussed above, the CPUC is proposing to address the perceived tightening of the RA market and need to ensure future resource sufficiency by recommending that OTC compliance deadlines be extended, combined with mandated procurement of a comparable amount of capacity (e.g., 2,500 MW) in the SCE transmission

[28]https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report%20rev.pdf
[29] https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442462515

access area. We would expect such an expansion in effective RA supply to avoid a price spike that may be associated with a tightening market.

Locally-Sited Renewables

To identify the potential of distributed solar generation in Long Beach, project team member Rincon Consulting developed a GIS analysis to identify parcels within the City that could potentially support the development of PV solar arrays. Rincon used a methodology of weighted factors that would positively or negatively influence the development of PV solar arrays on a subject parcel. That is, each land parcel in the City was given a score for their ability to support solar PV. Positive factors—ones that indicated a more promising location for PV development included, for example: if the parcel is owned by the City; if the parcel is identified as an environmental hazard concern site; and if the parcel is zoned for commercial or industrial use. Sample negative factors included: if the site was in a flood zone; if it is a designated Historical Resource; and if it is zoned as residential. The details of the analysis are included in Appendix 1.

Note that this analysis examined "in front of the meter" resources—ones that directly connect into the distribution grid. It did not examine the potential for "behind the meter" resources—ones that are used primarily to offset the electricity use of a house or other building rather than to sell power to the grid. This is not to say that rooftop solar should not be incentivized by a CCA—many CCAs do so—but rather that this analysis focused on resources that the CCA could purchase power from to serve the CCA's load.

The study confirmed the casual observation that there is little undeveloped land in the City. This eliminated what are generically better locations for of large-scale solar: industrial brownfield parcels. Second, the study found that the best remaining sites tended to be parking lots and structures over which PV arrays could be placed. However, these are significantly more costly and more difficult to develop than brownfield sites.

The analysis identified the top 200 parcels in the city for PV development. A typical project with a high score would be the City's ongoing effort to install nearly 4 MW of solar PV on parking canopies (i.e., on purpose-built structures shading existing City parking loads) and rooftops on City buildings. The 200 parcels could, if all were fully developed provide on the order of 100 megawatts of solar capacity. Of course, because most of these parcels are privately owned, only a fraction of this amount could actually be installed.

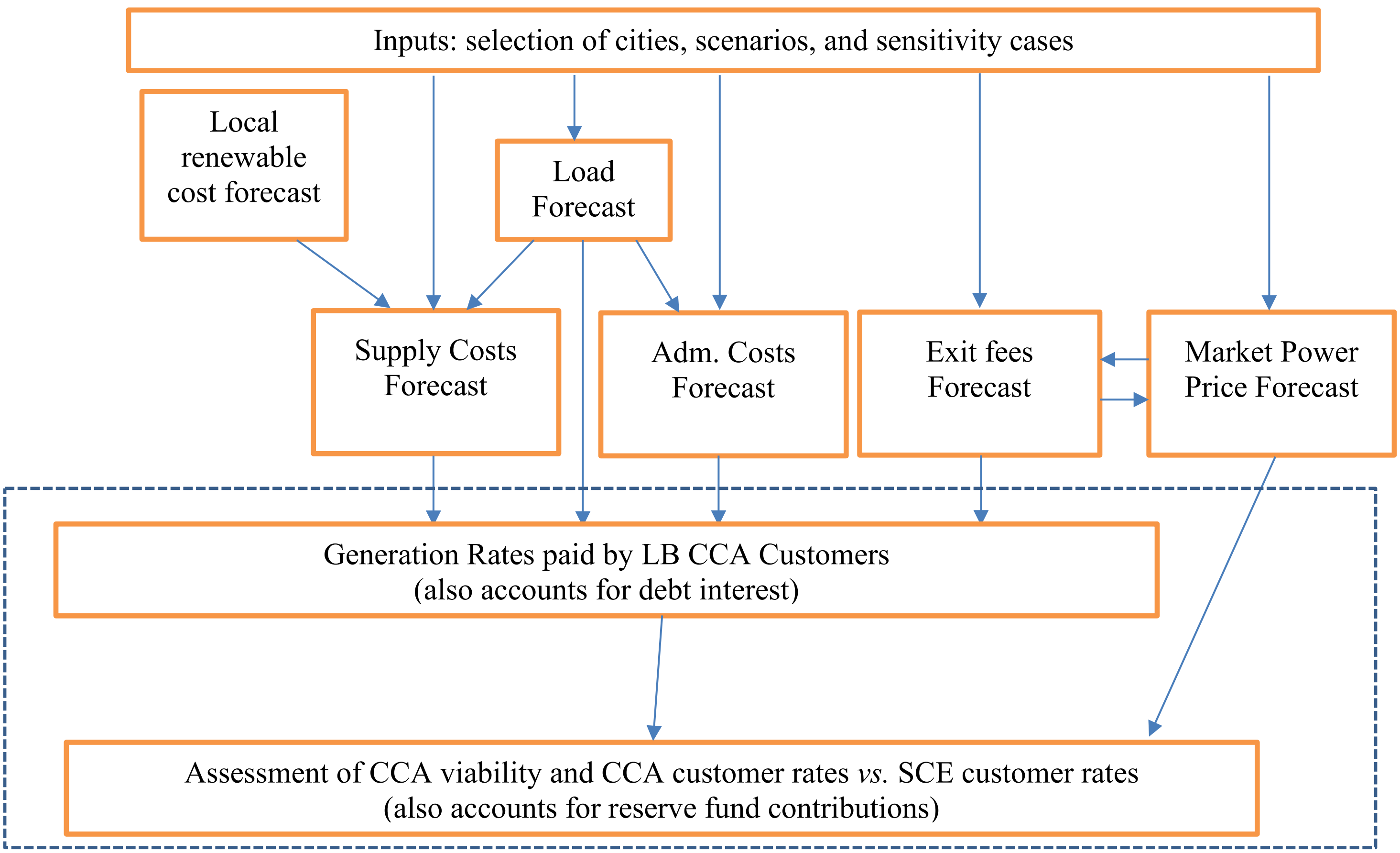
Given the difficulty and cost to develop the parking canopy based solar, the resource was not explicitly considered as a resource in the CCA analysis. This does not mean that such resources cannot play a role in a Long Beach CCA; only that they were not included as part of the financial analysis here.

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. Figure 12 provides a schematic of the pro forma analysis, outlining the input elements of the analysis and the output results. The analysis involves a comparison between the generation-related costs that would be paid by Long Beach CCA 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.

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 11. Pro forma Analysis



Startup costs

Startup costs are the costs the Long Beach CCA will incur before operations begin**.** Table 5 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 Long Beach were to move forward, these values would be refined based on more detailed projections.

Table 5. Estimated Start-Up Costs

Item	Cost	One-time or Ongoing?
Technical Study	$200,000	One-time
JPA Formation/Development	N/A	One-time
Implementation/Business Plan Development	$100,000	One-time
Power Supplier Solicitation & Contracting	$100,000	Ongoing
Staffing	$1,500,000	Ongoing, lower initially
Consultants and Legal Counsel	$700,000	Ongoing at reduced level
Marketing & Communications (incl. out-out)	$700,000	Ongoing at reduced level
SC&E Service Fees	$50,000	Ongoing at reduced level
CCA Bond	$150,000	One-time
Equipment and lease	$1,000,000	Ongoing
Miscellaneous (contingency)	$500,000	Ongoing at reduced level
Total	$5,000,000	
Working Capital	~$15,000,000	One-time; maximum line of credit amount
Total	**$20 million**	

Typically, the city forming a CCA would directly pay for the initial start-up costs, such as the technical study. 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 load 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 loads could be rolled into a longer-term 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 $15 million when the Long Beach CCA is fully operational (i.e., serving all potential customers.)[30]

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.

[30] 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.

These startup costs are assumed to be financed over 5 years at 5% interest.[31] 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 plan for times 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 15% of its annual revenue. 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 6, below summarizes the assumed ongoing administrative and general costs. These costs are assumed to trend with inflation (e.g., escalate at about 2% per year).

Table 6. Ongoing Administrative and General Costs

	2021	2022	2023	2024
SCE Fees, $/cust,/month	$0.061	$0.063	$0.063	$0.068
Data Management Fees $/cust./mo.	$1.02	$1.05	$1.05	$1.11
Administration – Labor[32]	$1,167,000	$2,824,000	$3,445,000	$3,689,000
Administration- Non-Labor	$218,000	$290,000	$300,000	$314,000
Outreach-communications	$1,203,000	$241,000	$110,000	$110,000
Professional Services	$449,000	$770,000	$520,000	$495,000
Data Management Fees	$2,325,000	$2,384,000	$2,449,000	$2,501,000
SCE Metering and Billing Fees	$139,000	$143,000	$147,000	$150,000
Total	$5,501,000	$6,652,000	$6,971,000	$7,259,000

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 Long Beach CCA 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 Long

[31] 6% is approximately the prime rate plus 100 basis points.
[32] See page 58 for staffing estimate details.

Beach CCA'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.

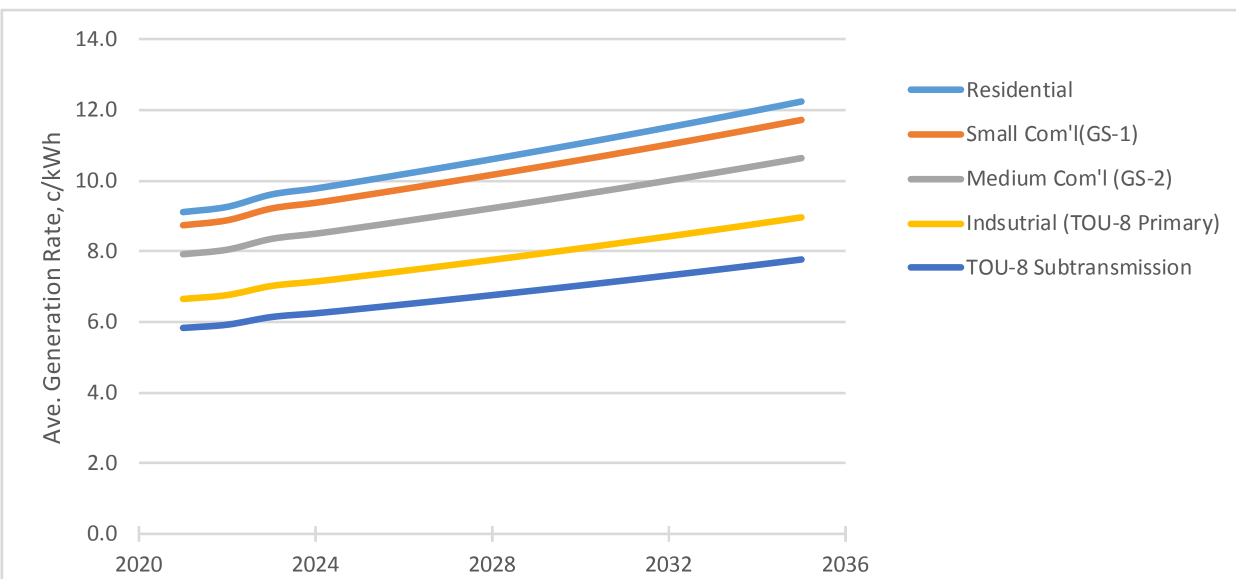
To develop this forecast, the key cost drivers of each of SCE's generation rate components were examined, separately evaluating costs for renewable and non-renewable energy purchases, for SCE-owned generation facilities, and for capacity purchases. The study assumed that near-term changes to SCE's generation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

The forecast further assumes that SCE is compliant with the renewable and carbon-free requirements recently 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 Long Beach CCA, SCE would need minimal if any new renewables to meet the 2030 goal.

The forecast for SCE's generation resources are based on publicly available data and forecasts. As with the CCA cost forecast, we relied on the market price forecast produced by ZGlobal to estimate the cost of market purchases. However, since SCE protects data that would reveal its detailed power procurement activities (e.g., hedging), we were unable to perform the hourly analysis completed for Long 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 2.5% per year. This forecast is show in Figure 13, below.

Figure 12. 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.

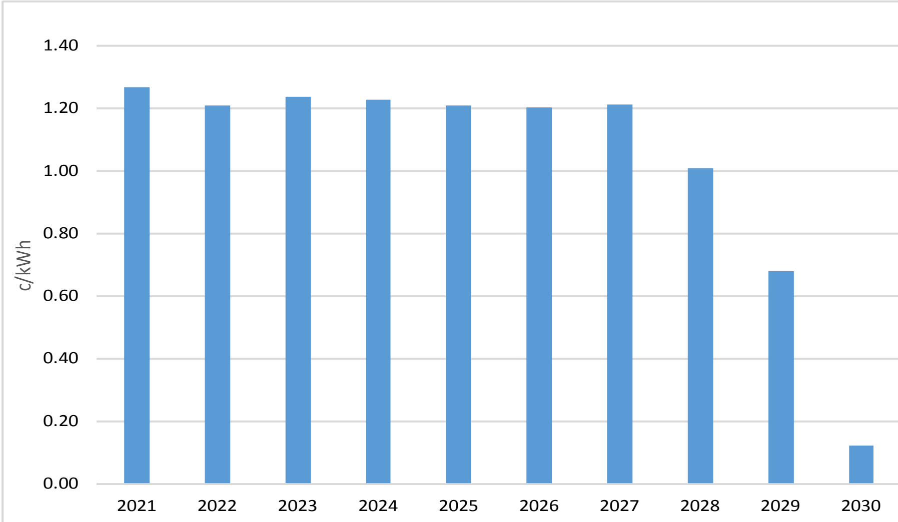
The PCIA is not paid directly by the CCA, but by the individual customers taking CCA service. Thus, it does not appear explicitly on the CCA's books, however it must be accounted for in any CCA cost analysis. While both CCA customers and customers that choose to remain in SCE bundled service pay this 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 through 2030. Based on our modelling, we expect the PCIA to remain between 1.0¢ and 1.3¢ per kWh through 2027. After 2027 the PCIA is modeled to decrease markedly until it is nil in 2032.[33] 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 2030 is shown in Figure 14.

Figure 13. Forecast Average PCIA

[33] It could, in fact, be negative after 2030, but for the conservatism, the modeling assumes that it does not go below zero.



SCE Green Option Tariff

CCA's frequently offer their customers the option to have 100% of their power met using renewable resources, albeit at a higher rate. A Long Beach CCA could offer such a rate option. However, Long Beach customers currently have something akin to this option via SCE's Green Tariff Shared Renewable (GTSR) Program. The program was established in 2016 under Senate Bill 43, and pursuant to CPUC Decisions 15-01-051 and 16-05-006, to extend access to renewable energy to ratepayers that are currently unable to install onsite generation.[34] It offers homes and businesses the option to purchase 50% or 100% of their energy use from solar resources. The program provides those with homes or apartments or businesses that cannot support rooftop solar the opportunity to meet their electricity requirements through renewable energy and support the growth of renewable energy resources.

A customer must positively elect to be on the GTSR (i.e., it is "opt-in."). Once enrolled, there is no minimum length of time that a customer must take service under this Schedule, nor is there any termination fee for departing the program. Customers are eligible to remain on the Green Rate Program for up to 20 years from the date they first began service.

A generating facility eligible to provide power to GTSR customers must be (a) solar; (b) new; (c) between 500 kW and 20 MW; and (d) located in SEC's service territory. Renewable Energy Credits (REC) generated by facilities under the GTSR program cannot be used by SCE for RPS compliance.

The GTSR-Green Rate (GTSR-GR) consists of (a) a credit equal to the average generation rate of the customer's otherwise applicable tariff; (b) an adjustment change to reflect the difference between the time of delivery profile the GTSR solar facility and the customer's class consumption profile; (c) a charge for the renewable power, the PCIA and the CTC; (d) a CAISO grid charge; (e) an charge for Resource Adequacy (RA); and a program administration charge. Ignoring the PCIA and CTC, the average cost to a GTSR customer is about 1.1¢/kWh higher

[34] California Public Utilities Commission, Decision 15-01-051, p.3

than the SCE otherwise applicable generation rate. The program is open for enrollment until subscriptions reach 269 MW.

A Long Beach CCA has the flexibility to offer rates corresponding to 100% green power, or any green power content greater than the state's minimum. While MRW believe that is could likely do so at a competitive price, this option was not explicitly investigated here.

Chapter 3. Cost and Benefit Analysis

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 Long Beach CCA are is summarized in this chapter. While a full pro forma through 2035 is modeled and included in the appendix, the uncertainty in the forecast elements make the latter 15 years less pertinent.

Scenarios

Table 7 shows the scenarios examined: two supply scenarios, with two customer sets.

Table 7. Power Content and Customer Options Considered

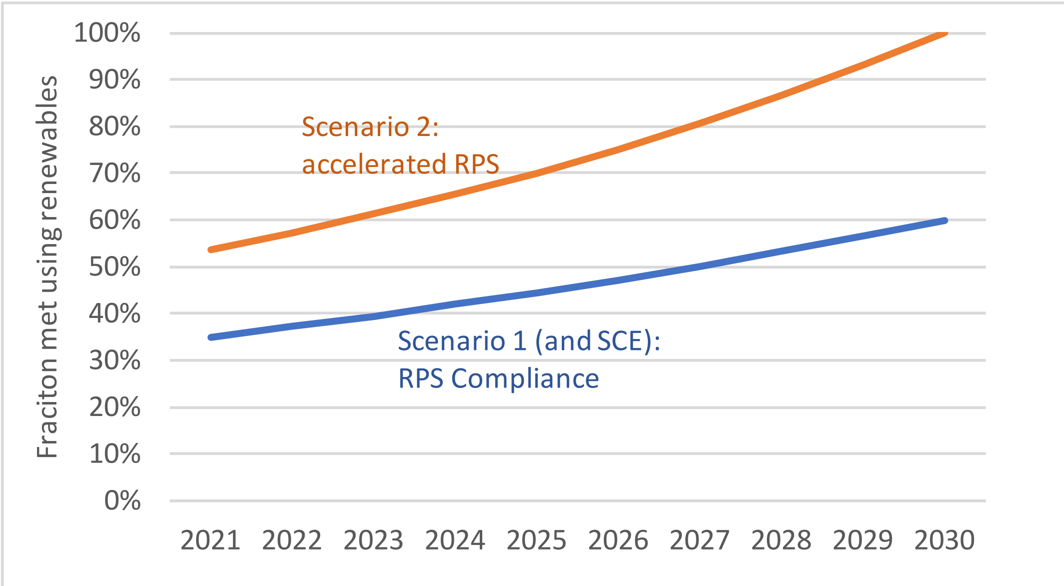
	All Customers Served	All Customers Except TOU-8 subtransmission Served
Supply Scenario 1: Meet State Renewable mandates and SCE's GHG emissions	X	X
Supply Scenario 2: 50% renewable power content in 2021, ramping to 100% in 2030	X	X

Supply Scenarios

Supply Scenario 1 assumes that the hypothetical Long Beach CCA simply complies with the State's requirements concerning renewable power. It starts in 2021 with 37% of its power being met using renewable resources and escalates this faction to 60% by 2030. Above the renewable output, hydropower is assumed to be used (priced as a modest premium above system power) so that the CCA's net GHG emissions is no greater than SCE's. The remaining fraction of the CCA's power needs are assumed to be met using system power form the CAISO.

Supply Scenario 2 assumes that the CCA goes beyond the State-mandated RPS requirements and utilizes increasingly greater amounts of renewable power. Specifically, Supply Scenario 2 assumes that the CCA will start at 50% renewable content in 2021 and achieve net 100% renewable power by 2030.

Figure 14. CCA Scenario Renewable Power Content



Customer Scenarios

Two customer scenarios are considered: one in which CCA service is offered to all electric customers in the City and one in which CCA service is offered to all electric customers except those served on the TOU-8 subtransmission tariff.

Why Separate out TOU-8 Subtransmission Customers?

The cost to provide power to a CCA depends upon when the CCA must procure power. If its load is concentrated more in hours when the market prices are high, them the total cost of power to the CCA will be higher. Similarly, if the CCA has high peak loads (MWs) relative to its average load, then costs increase because of the need to procure resource adequacy, which is a function not of the number of kWhs sold but the peak demand.

This thinking holds true for each customer class or SCE tariff. Customer classes, like residential, tend to consume power during times of higher prices while also having a higher peak load relative to the class's average load. This makes them, on average, more costly to serve. On the other end of the spectrum, industrial customers, including and especially those on Tariff TOU-8 subtransmission, tend to use power nearly full out 24 hours a day, seven days a week, and thus tend to be less costly to serve.

For Long Beach, the estimated cost to serve (COS) its largest industrial customers—those on Tariff TOU-8 subtransmission, is higher than the SCE's rate. This is clearly a very important issue for Long Beach, as over 25% of the load in the City customers served on the TOU-8 subtransmission tariff.[35] Most Southern California CCAs—all but one, in fact—do not have significant TOU-8 subtransmission load, and as such do not have to address this issue. The one

[35] While 40% of the City's load is large commercial and industrial, only 25% is served on this specific rate schedule,

remaining, the Clean Power Authority (CPA) has chosen not to meet or beat this SCE rate, but instead offers rates to this class at CPA's cost of service. For practical purposes, this means that over half of CPA's TOU-8 subtransmission load has opted to remain with SCE. CPA was quite explicit about this rate differential when phasing in the large customers, reaching out to each of them individually to ensure that they could opt-out to SCE if they so wanted.

Furthermore, as discussed above, the CCA will likely not be able to serve the TOU-8 sub-transmission class at rates that would both be lower that SCE and generate net revenue for the CCA. As such, the CCA would have to either have the residential and small commercial classes to subsidize these rates or offer rates that would be higher than SCE and thus cause the price-sensitive large users to opt-out of the CCA program.

Therefore, we include the second customer scenario, which assumes that customers on SCE TOU-8 subtransmission rate are not served. This reduces the load the CCA would serve by about 25%.

Supply Scenario 1

Supply Scenario 1 serving all customers

Figure 16 shows the Supply Scenario 1 forecast of average CCA costs and SCE's generation rates, assuming that all customers are served, including TOU-8 subtransmission ones. 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 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.

The bottom-most green segment represents the cost of renewable power to the CCA. The renewable power costs ramp up with increasing renewable content, as required by SB 100.

The brown segment is for the costs of non-renewable, wholesale market power. This segment slowly decreases, as renewable power increases.

The 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, even if the "intermittent" renewable resources are not generating at their optimal rate (e.g., solar on rainy days). The more intermittent renewables—solar and wind—that are added to the CCA's generating mix, the more back-up capacity is needed to ensure reliability.

The yellow segment is for operations and debt service. That is, from 2021 through 2024 the loans associated with the start-up costs are paid down. Once that debt is retired, the operations costs segment decreases markedly.

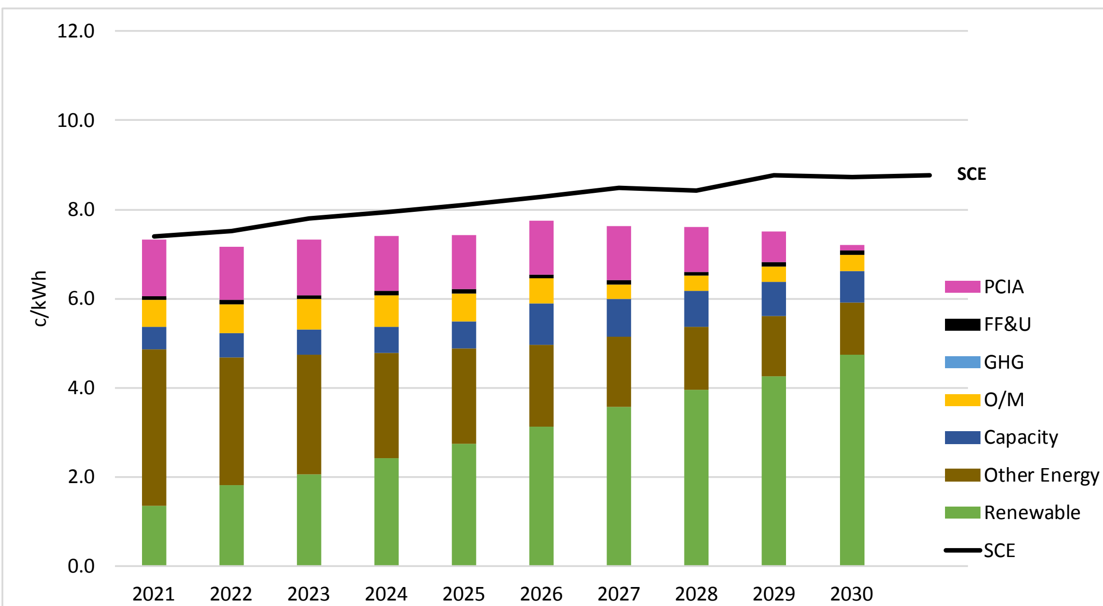
The light blue segment is for carbon cap and trade allowances. Note that for practical purposes, the carbon cap-and-trade allowances would be built into the purchase prices of natural gas-fired market resources. However, because it is an important variable on its own, the figures have separated it out.

The narrow black segment is for franchise fees and uncollectibles. Franchise fees are those collected the SCE and paid to the City for the right to operate the electric monopoly franchise in the city. It is paid as a percent of each customer's total bill and is automatically built into SCE's rates. So that cities remain financially whole when customers' power is provided by a CCA, SCE charges CCA customers a "franchise fee surcharge."[36] Second, as with any business, a certain fraction of the CCA's bills will not be paid and are treated as "uncollectible." To account for these two factors, one must gross up the CCAs rates by about 1.2%.

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 (for 2019) and applies the known and anticipated changes to the wholesale power market prices and SCE's power purchase contracts.

Figure 15. Supply Scenario 1 Average CCA Cost Projection (serving all customers)



[36] See SCE Tariff Schedule FFS.

As shown in Figure 17, the costs of CCA operation in Supply Scenario 1 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:

- 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).
- The CCA can change customers the same rate as SCE am retain the margin to build up cash reserves for a rainy day.
- 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.

WHAT DOES A 0.5¢/KWH MARGIN MEAN?

If the CCA uses it to reduce rates, then the 0.5¢/kwh would reduce CCA customers' electric bills by ~3%. For a residential customer this translates to about $2.50 per month,

If the CCA retains the 0.5¢/kwh margin, it would generate about $15 million annually. If this was set aside, it would take from two to three years for the CCA to reach its reserve target 15% of annual revenues.

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

In 2021, this "margin" between CCA average cost and SCE rate is about 0.4¢/kwh, increasing to about 2¢/kwh in 2030. Note that this does not mean that the CCA can or will fully pass on this margin as rate savings to its customers. There are other uses that the CCA leadership may choose to use this margin for, most notably the generation of a rate reserve fund. As discussed elsewhere, other CCAs have chosen to use their margins for more generous solar PV programs, incremental energy efficiency, EV charging, or other programs that benefit the community.

Supply Scenario 1 without serving TOU-8 subtransmission customers

Figure 17 shows the CCA cost versus SCE rate comparison for Supply Scenario 1 with the CCA serving all but the TOU-8 subtransmission customers. (It is Analogous Figure 16, figure for Supply Scenario 1.) The costs of CCA operation are consistently below that of the SCE rate, with "margins" between CCA average cost and SCE starting at 0.7¢/kwh, increasing to ~2.2¢/kwh in 2030.

Figure 16. Supply Scenario 1 Average CCA Cost Projection (not serving TOU-8 subtransmission)

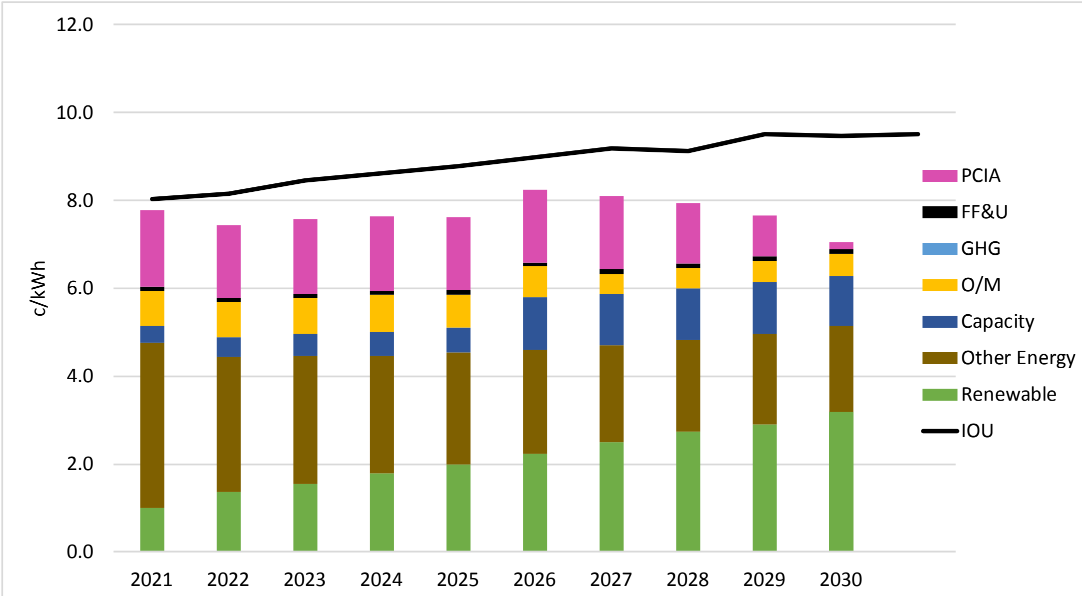


Table 8 shows the "margin"—the gap between the CCA cost of service columns without the TOU-8 subtransmission load the average margin is greater by about 0.2-0.4¢/kWh.

Table 8. Supply Scenario 1 CCA Margins, ¢/kWh

Year	Serving All Customers	Serving all but the TOU-8 subtransmission Customers
2021	0.4	0.7
2022	0.9	1.1
2023	1.1	1.3
2024	1.1	1.4
2025	1.3	1.6
2026	1.1	1.1
2027	1.5	1.5
2028	1.5	1.5
2029	1.7	2.1
2030	2.1	2.4

Table 9 shows, on a dollar basis, the potential total margins available to the CCA under the Scenario 1 with no large industrial load being served. For perspective, the table also contains a column showing how much of the margin would be needed to offer a 5% discount off the average SCEs rates. As the table illustrates, a 5% rate savings could not be offered in the first year. In practice, in the first few years any rate savings would have to be balanced against funding of reserves.

Furthermore, the total margins would likely have to remain in the CCA (i.e., not transferred to the general fund) for rate reductions, CCA reserve accumulation, or CCA/energy-related projects.

Table 9. Scenario 1 CCA Margins ($millions per year), not including rate reduction or contributions to reserves

Year	Scenario 1 with Deferred Industrial Service	Cost of a 5%* Rate savings
2021	$7.3	$8.9
2022	$24.5	$18.8
2023	$28.8	$19.5
2024	$30.7	$19.8
2025	$39.7	$20.1
2026	$24.7	$20.5
2027	$32.6	$20.8
2028	$33.0	$20.6
2029	$45.6	$21.4
2030	$54.2	$21.2

Greenhouse Gas Emissions

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 power sources: large hydroelectric dams and nuclear power from the Palo Verde Nuclear Power Plant, of which SCE is a partial owner. The GHG-emitting portfolios for Power Supply Scenario 1 and SCE are shown in Table 9.

Table 10. CCA (Supply Scenario 1) and SCE Power Content in 2022

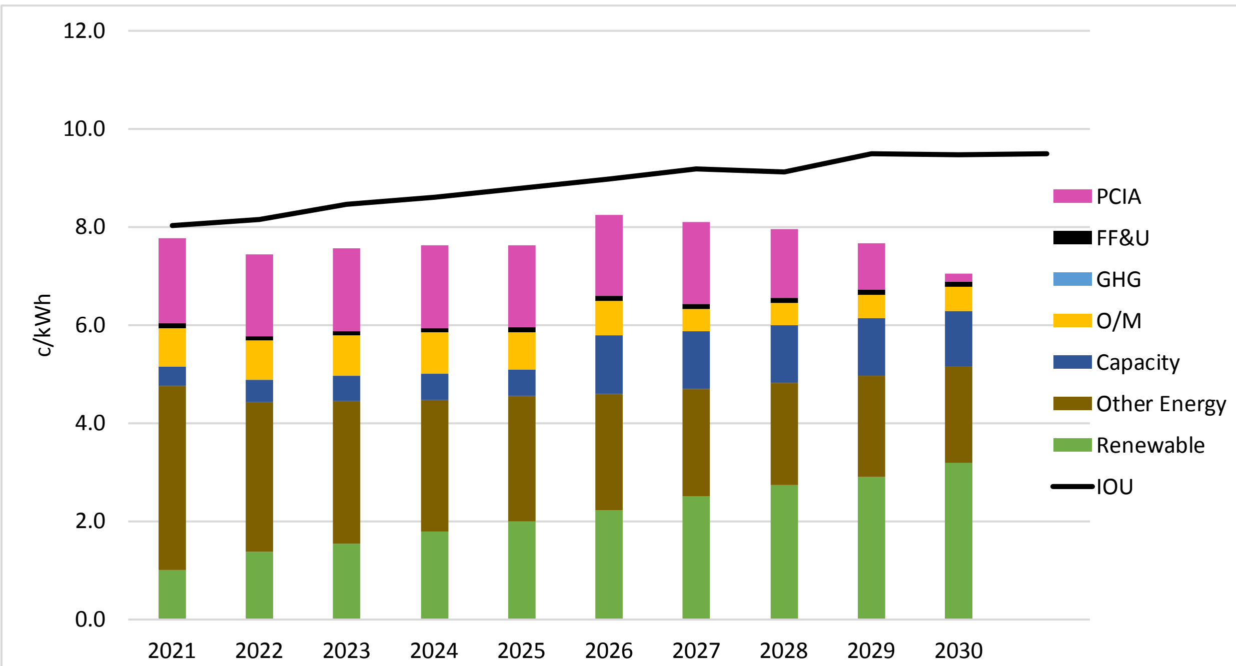
	CCA Scenario 1	SCE
Renewable	37%	37%
Hydro	15%	7%
Nuclear		8%
GHG-Free	**52%**	**52%**
Gas		3%
System	48%	45%
TOTAL	100%	100%

Supply Scenario 2 (High Renewable Penetration Chase)

Supply Scenario 2 serving all customers

Figure 18 shows the Supply Scenario 2 projections of average CCA costs and SCE's generation rates assuming that the CCA serves all customers. As with Figure 19, 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.[37] When the bars are below the 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.

Figure 17. Supply Scenario 2 Average CCA Cost Projection (serving all customers)



Note that even though by 2030 the CCA will be providing 100% net green power, it will still be incurring some costs for "brown" system power. This is because, as described in the *Renewables – what does it mean to be 100% Green?* section earlier, even when the CCA generates the same number of renewable kilowatt-hours as its customers consume, the timing of the renewable generation and consumption do not align. Therefore, there will be hours where the CCA is effectively selling its excess green generation when it is generating more renewable power than its customers are consuming and purchasing system power when customer consumption exceeds the CCA's renewable generation. When the CCA is selling its excess green energy, those sales

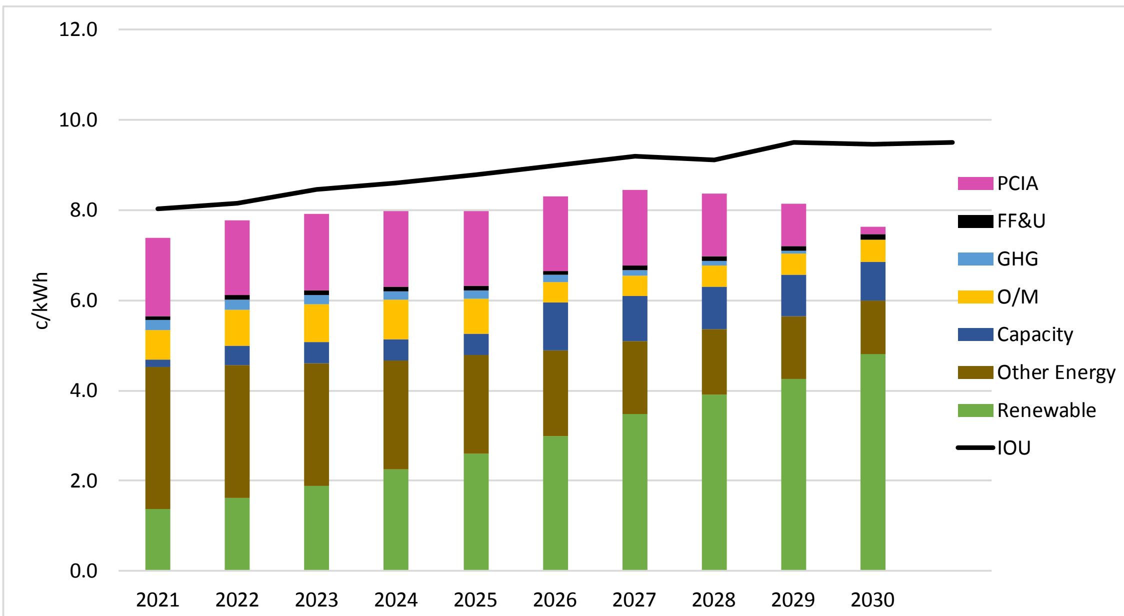
[37] The SCE generation rates in these comparisons are still the default SCE generation rates, NOT the SCE Green Tariff. We keep this comparison because a customer would default back to SCE's standard generation rate no matter the renewable content of the CCA.

revenues are credited against the renewable costs in the green segments of the cost columns in Figure 18, while the costs of system power are shown explicitly as the brown "Other Energy" column segments in Figure 18.

Supply Scenario 2 without serving TOU-8 subtransmission customers

Figure 19 shows the Supply Scenario 2 projections of average CCA costs and SCE's generation rates assuming that the CCA serves all customers. Like with Scenario 1, not serving the TOU-8 subtransmission customers increase the Scenario 2 margins by 0.3-0.4¢/kWh.

Figure 18. Supply Scenario 2 Average CCA Cost Projection (not serving TOU-8 subtransmission)



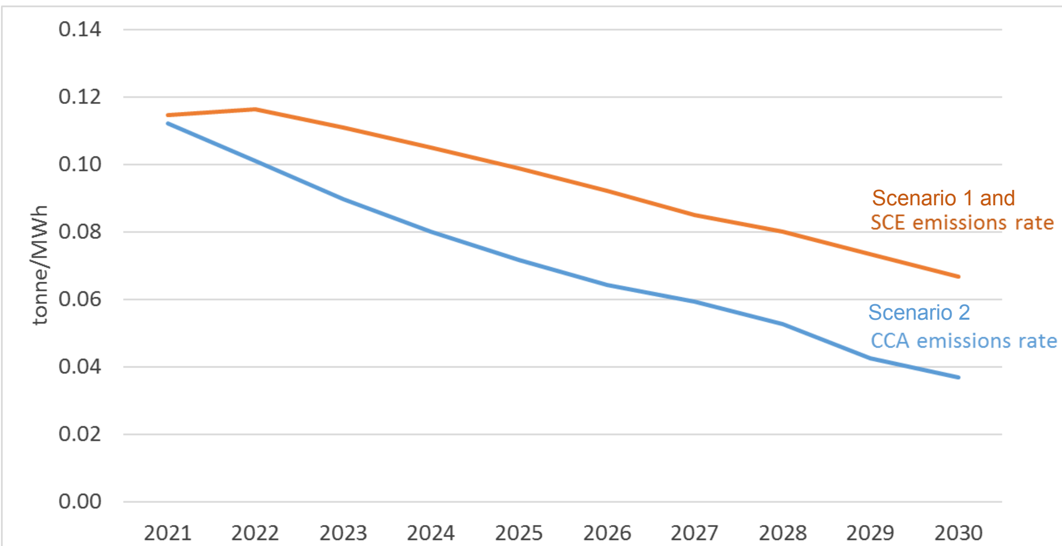
Greenhouse Gas Emissions

As shown in Figure 20 and Table 10, under Supply Scenario 2 the CCA can achieve reduced GHG emissions relative to SCE service, even without relying upon non-RPS compliant GHG resources like large hydro power. Emissions could, of course, be reduced further if the CCA utilized non-RPS compliant GHG resources like large hydro instead of system power for the balance of its generation.

Table 11. CCA and SCE Power Content in 2022

	CCA Scenario 1	CCA Scenario 2	SCE
Renewable	37%	57%	37%
Hydro	15%	15%	7%
Nuclear			8%
GHG-Free	**52%**	**72%**	**52%**
Gas			3%
System	48%	28%	42%
TOTAL	100%	100%	100%

Figure 19. Scenario 2 Carbon Emissions Rates



Scenario Comparisons

Table 11 shows the average margins for the CCA for both supply scenarios, with and without the TOU-8 subtransmission class being served. As the table shows, the margins are from 0.2¢/kwh to 0.5¢/kwh greater when the TOU-8 subtransmission class is not served.

Table 12. Scenario Margins, ¢/kWh

	Serving all customers		Serving all but TOU-8 subtransmission	
	Scenario 1	Scenario 2	Scenario 1	Scenario 2
2021	0.4	0.1	0.7	0.5
2022	0.9	0.3	1.1	0.8
2023	1.1	0.5	1.3	0.9
2024	1.1	0.5	1.4	1.0
2025	1.3	0.7	1.6	1.2
2026	1.1	0.5	1.1	0.8
2027	1.5	0.8	1.5	1.1
2028	1.5	0.8	1.5	1.1
2029	1.7	1.3	2.1	1.6
2030	2.1	1.5	2.4	1.9

Chapter 4. Sensitivity of Results 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 must be 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 natural gas and power market prices

(3) higher resource adequacy compliance costs,

(4) Higher PCIA than forecast, and

(5) Lower SCE Rates

The specific assumptions on the sensitivity scenarios are shown in Table 12.

Table 13. Sensitivity Case Definitions

Sensitivity Case	Definition
Base	Supply Scenario 1, no TOU-8 subtransmission load
Higher renewable costs	Renewable costs 20% higher than Base
Higher gas and power prices	Power Prices 33% higher than Base
Higher Resource Adequacy Cost	RA compliance costs 100% higher than Base
Higher PCIA	PCIA 33% higher than calculated in Base
Lower SCE Rate	SCE rates 5% lower than in Base

Sensitivity Case Results

Figure 21, summarizes the 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 cost to average cost for the CCA to serve its load, including the PCIA. (Each case is discussed in detail below) 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. When the bar is negative, the CCA's cost of service is greater than SCE's rates and the CCA would either have to charge rates higher than SCE or operate at a deficit. Consistent with the rest of the analysis, the margins are the smallest during the first years of operation.

Figure 20. Sensitivity Results

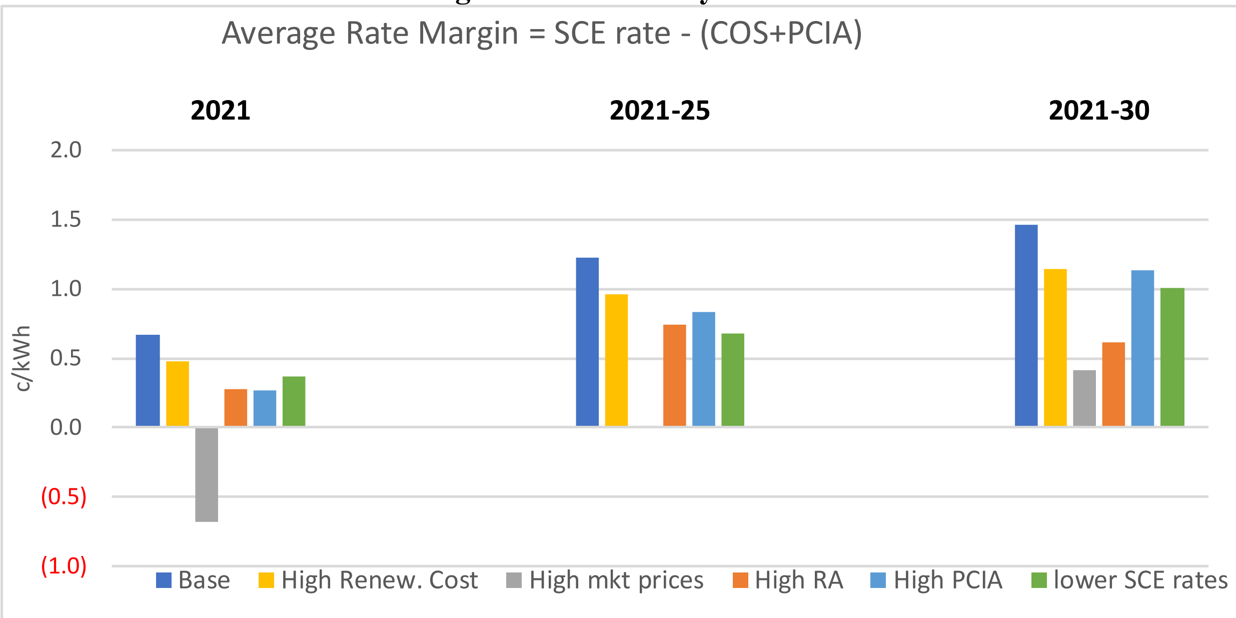


Table 13 provides some additional context to what the margins shown in the prior figure mean. For each case, the table indicates if the CCA could (a) offer a 3% discount off its customers' total electric bills (i.e., both the CCA energy changes and the SCE delivery charges and PCIA); that same 3% discount and fully fund the CCA's reserve fund target by 2025; and (c) offer a 5% rates savings and fully fund the reserves. As the table shows, only in the base case—Scenario 1 serving all customers except TOU-8 subtransmission, could the last criteria be met. In all of the others, a 5% rate savings could not be achieved.

Table 14. Sensitivity Cases Implications

Could the CCA:	Offer 3% rate savings? *	Offer 3% rate savings* and fully fund reserve by 2025?	Offer 5% rate savings and fully fund reserve by 2025?
Base	Yes	Yes	Yes
High Renewable Costs	Yes	Yes	No
High Market Prices	No	No	No
High RA Prices	Yes	No	No
High PCIA	Yes	Yes	No
Low SCE Rate	Yes	No	No

**Off of Total bill (CCA generation and SCE charges), over each of the first 5 years.*

Higher Renewable Cost Sensitivity

In the Higher Renewable Cost sensitivity, renewable prices are set 33% higher than in the base case. These higher prices affect both the CCA and SCE, but they have a greater effect on the CCA because SCE has significant amounts of renewable resources under long-term contract, which would not be affected by future renewable prices. As shown in Figure 21, with the high renewables assumption the average margin over 10 years is 1.1¢/kwh. Under this case, the CCA could offer a 3% rate discount and meet its reserve targets by 2025.

Higher Power Prices Sensitivity

California power prices have long been a function of natural gas. Natural gas prices have been low and relatively steady over the last few years, but they have historically been quite volatile and subject to significant swings from local supply disruptions (e.g., Hurricanes Katrina and Rita in 2005). Power and natural gas increases affect power supply costs for both CCA and SCE, but, the CCA is more sensitive than SCE. This is largely because the assumed CCA power portfolio in the early years relies on non-unit specific contracts for RPS compliance,[38] which could expose the CCA to greater market risk. Under this case, the CCA could not ever offer a 3% rate discount. However, using sound risk management strategies, such as hedging and locking in power prices can help shield the CCA against higher market power prices.

Higher Resource Adequacy Costs Sensitivity

As discussed earlier, the cost to comply with RA requirements is both highly uncertain and likely to increase. In the Higher RA Cost sensitivity, RA compliance costs at 100% higher than the Base scenario. This increase could occur not only due to higher RA prices, but to changes in how much RA needs be procured as well as changes to how much "free" RA is allocated to the CCA through the "Cost Allocation Mechanism" (CAM) process.[39] As shown in Figure 21, with the high RA assumption the average margin over 10 years is 1.1¢/kwh. Under this case, the CCA could offer a 3% rate discount, but could not meet its reserve targets by 2025.

Higher PCIA Sensitivity

The models used to create this report explicitly simulate the calculation of the PCIA. Therefore, underlying changes to the market—higher or lower natural gas or high or lower renewable costs, explicitly ripple through to the PCIA. However, for the sake of interest and conservatism, this sensitivity represents a case where the PCIA is arbitrarily increased to the greater of 130% for the calculated PCIA or 1.0¢/kWh. This assumption only impacts the CCA. As shown in Figure 21, with the high PCIA assumption the average margin over 10 years is 1.1¢/kwh, which is about 20% less than the Base Case. Under this case, the CCA could offer a 3% rate discount, but could not meet its reserve targets by 2025.

[38] While not tied to a specific unit, these contracts are still Product Content Category ("bucket") 1 compliant.
[39] See pages 19-22 for a discussion if changing RA requirements.

Lower SCE Rate Sensitivity

Like with the PCIA, the models used to create this report explicitly simulate the calculation of the SCE rates. Therefore, underlying changes to the market—higher or lower natural gas or high or lower renewable costs, explicitly ripple through to both SCE and the CCA. However, rate setting is not fully predictable; MRW must rely upon public sources of data to understand and model SCE's rates. Therefore, as a conservative sensitivity, MRW explored the impact of our SCE rate forecast was 5% too high. In this case, the CCA could offer a 3% rate discount, but not meet its reserve targets by 2025.

Sensitivity Case Implications

There are three major implications that are illustrated by the sensitivity cases.

1. Under any single adverse assumption contained in the sensitivity cases, the CCA can generate positive margins during the first 5 years.
2. However, the margins are very modest and offer little opportunity for rate savings, and combinations of adverse events or prices could result in the CCA not being competitive.
3. The high market price case is both possible and, if not properly hedged against, causes negative margins in the first few years. If Long Beach is to pursue CCA in the next two or three years, it should carefully assess the power market to ensure that it can manage the risk and volatility of RA compliance.

Chapter 5. Example of a Hypothetical 5-Year Cash Flow Analysis & Financial Strategy

The scenario analyses in the prior chapters are based on more generalized assumptions. Because the first five years are of particular concern with respect to financing and cash flow, this chapter shows a more detailed potential monthly cashflow during the first five years. This analysis looks at cashflow over five years (2021-2025) and focuses on the startup, launch and early operational phases of the CCA.

This analysis includes a hypothetical financial strategy during the period when debt is 1) used to collateralize and launch the program and 2) subsequently paid off with net revenues generated over the initial years of operations. It does not represent a recommendation; an actual financing plan would be set by the CCA, in conjunction with its banking/financing partners. It is included here as an illustration of the details of what goes into the early year financing process.

The analysis reflects accounting structures, contract payment terms, credit and collateral requirements and other financial, regulatory and business process requirements of CCAs. The forecast horizon and level of specificity in this report section, related appendix and accompanying spreadsheet provided to the City is based upon budgeting workbooks employed by operational CCAs to support financing and power purchase negotiations.

Scenario Assumptions

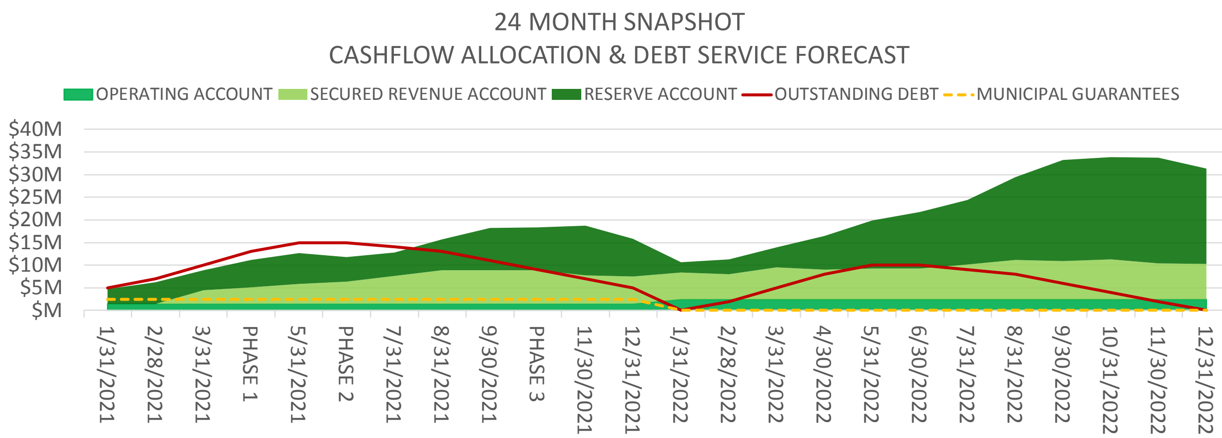
The modeling exercise is based on **Scenario 1**, where the CCA enrolls all bundled service customers, apart from the subset of large industrial customers taking service from SCE on TOU-8-subtransmission rate schedules.

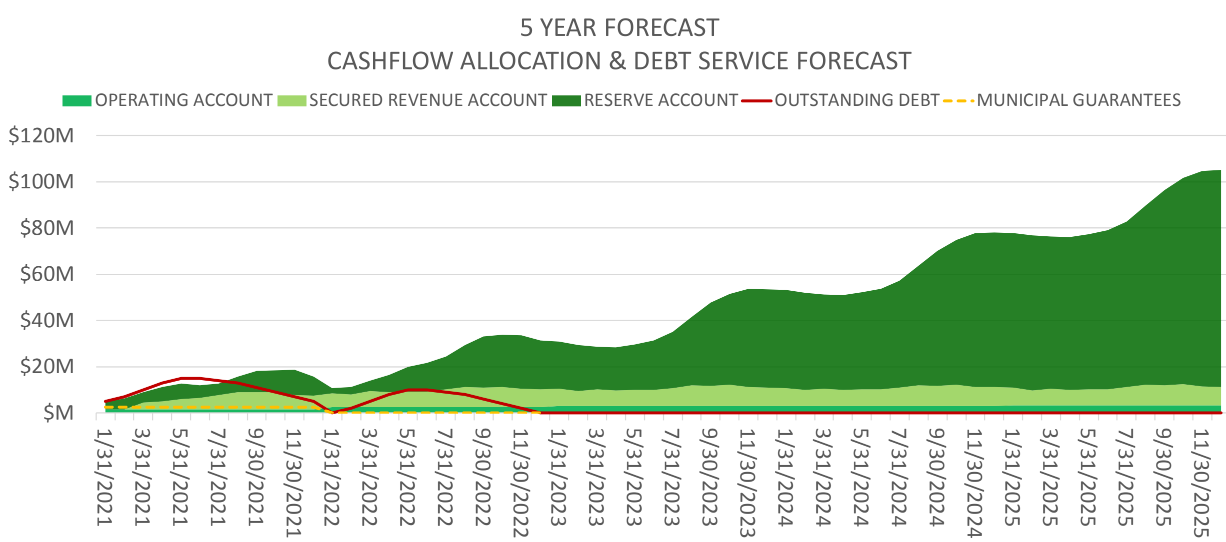
Financing Requirements & Debt Service Forecast Results

The $15 million in financing is assumed to be provided by:

- $5 million term loan at 6% interest
  - Municipal guarantee: 50% ($2.5 million)
  - CCA guarantee: secondary lien on revenues
- $10 million line of credit (LOC) at 2% interest
  - Municipal guarantee: 0%
  - CCA guarantee: secondary lien on revenues

The CCA launches in April 2021, pays off the term loan within a year, and continues to draw upon the line of credit during the second year of operations. Thereafter, the enterprise has collected sufficient reserves to self-fund annual cashflow requirements — as visualized in the two graphs below:





- The **Secured Revenue Account** is a restricted multi-party waterfall managed by the CCA's collateral trustee (a neutral, third-party financial institution). During program operations, customer receipts are deposited by the utility directly into this account. As a credit enhancement, energy suppliers have first rights to revenues in this account (lenders have subordinate rights), which must maintain a minimum balance for collateral and to pay for electricity market expenses and contingencies. To support forward energy purchases prior to program launch, funds from loans or government contributions are deposited by the CCA into this account; post-launch, an additional amount is typically accrued to provide further collateral.
- Each month thereafter, funds in excess of the required amount are disbursed to the CCA's **Operating Account**, which pays for non-energy expenses each month, and typically holds funds to cover 4-6 weeks of these expenses.
- From there, additional funds are deposited into the **Reserve Account**, which retains funds for future rate relief, disburses funds to satisfy collateral obligations, and also supplements as necessary the Secured Revenue Account and Operating Account.

Revenue Allocation and Cost Comparison to SCE

The allocation of revenues collected via the CCA's rates are shown in the table and graph below, along with a comparison to what CCA customers would have paid if served by SCE:

REVENUE ALLOCATION & COMPARISON TO SCE ($/MWh)

	2021	2022	2023	2024	2025
On-Peak Power	$29.63	$25.34	$24.96	$24.36	$24.36
Off-Peak Power	$9.97	$10.23	$10.63	$11.03	$11.03
Renewable & GHG Free	$6.11	$7.09	$7.19	$7.36	$6.66
Capacity	$4.28	$5.37	$5.86	$6.17	$6.94
Grid Charges	$2.57	$2.37	$2.39	$2.41	$2.50
Utility Fees	$0.24	$0.36	$0.35	$0.35	$0.36
Services	$2.24	$1.99	$2.01	$2.05	$2.07
Outreach, Marketing & Mailers	$0.70	$0.04	$0.05	$0.05	$0.05
Staff & Overhead	$2.93	$2.74	$2.93	$3.08	$3.25
Local Programs & Development	$0.45	$0.69	$1.82	$1.82	$1.83
Financing Charges	$0.42	$0.10	$0.05	$0.05	$0.02
Reserves	$9.14	$9.20	$10.05	$11.18	$12.78
Uncollectibles	$0.35	$0.33	$0.34	$0.35	$0.36
CCA AVERAGE RATE	**$69.03**	**$65.90**	**$68.72**	**$70.34**	**$72.33**
Power Charge Indifference Adjustment (PCIA)	$12.74	$12.76	$13.05	$12.97	$12.89
TOTAL CUSTOMER 'EFFECTIVE' RATE TO COMPARE	$81.77	$78.66	$81.77	$83.32	$85.22
SOUTHERN CALIFORNIA EDISON AVERAGE RATE	$86.80	$83.74	$86.80	$88.35	$90.18
CCA RATE DECREASE	$5.03	$5.08	$5.03	$5.04	$4.96
% Discount to SCE Generation Rate	5.80%	6.07%	5.80%	5.70%	5.50%

Key Performance Indicators

The table below provides various summary figures and Key Performance Indicators (KPIs).

For example, CCAs seeking to establish a credit rating, as MCE Clean Energy and Peninsula Clean Energy have done, within the first 3-5 years of operations are advised to accrue reserves that cover their operating expenses for various lengths of time:

- Baa rating: 30-90 day operating reserve
- A rating: 90-150 day operating reserve
- AA rating: 150-250 day operating reserve

The CCA is forecasted to satisfy these requirements over the 5-year forecast period — while additionally saving customers nearly $50 million in rate savings and providing $14 million in local program funding:

SUMMARY FIGURES AND KEY PERFORMANCE METRICS

	2021	2022	2023	2024	2025
Revenues from Operations	$76,282,309	$143,490,033	$150,641,968	$153,684,098	$157,411,761
Operating Expenses	$66,135,282	$123,352,329	$128,491,295	$129,140,303	$129,462,963
Financing Charges	$0	$0	$0	$0	$0
YE retained net revenues (cumulative, accrual basis)	$10,147,027	$30,284,731	$52,435,404	$76,979,198	$104,927,997
Annual, as a % of revenue	13%	14%	15%	16%	18%
Cumulative, in terms of days of OpEx	**56**	**90**	**149**	**218**	**296**
YE cash position	$16,921,614	$32,574,451	$54,664,135	$79,174,640	$106,307,107
Unrestricted cash reserves	$8,213,367	$21,145,945	$42,524,057	$66,873,272	$93,817,210
Maximum Debt	$15,000,000	$10,000,000	$0	$0	$0
YE Outstanding Debt	$5,000,000	$0	$0	$0	$0
Municipal Guarantees (liability)	$2,500,000	$0	$0	$0	$0
Debt Service Capacity Ratio (DSCR)	2.31	3.54	43.32	-	-
Energy expenses as a % of revenues	76%	76%	74%	73%	71%
Reserve collection as a % of revenues	13%	14%	15%	16%	18%
Overhead as a % of revenues	10%	9%	10%	11%	10%
Power Charge Indifference Adjustment (PCIA) payments	$14,150,367	$28,040,458	$28,755,593	$28,480,334	$28,195,143
PCIA as % of CCA rates	18%	19%	19%	18%	18%
Renewable content of CCA portfolio	37%	39%	42%	44%	47%
Carbon Free (hydro & renewable content)	52%	51%	52%	54%	55%
Local Program Funding	$500,000	$1,500,000	$4,000,000	$4,000,000	$4,000,000
Rate decrease vs. SCE	5.8%	6.0%	5.8%	5.7%	5.5%
Community savings from rate decreases (annual)	$5,591,644	$10,994,780	$11,092,319	$11,057,680	$10,848,556
Community savings from rate decreases (cumulative)	$5,591,644	$16,586,423	$27,678,742	$38,736,422	$49,584,978

Customer Phase-In Strategy

An important factor in any CCA's startup financing strategy is the customer phase-in schedule. Structuring it well is actually a primary purpose of the entire modeling exercise. Doing so requires forecasting and analyzing cash-flows on a monthly basis during the critical period over which debt is repaid.

The highest-level dynamic — which is primarily the result of SCE's rate structures and the PCIA charge — is that revenues from customers fluctuate widely over the course of the year in aggregate. The different rate structures mean these patterns also vary between different groups of customers. On average, nonresidential customers actually cause losses for the CCA out of eight months out of the year — but then bring in substantial net revenues in June through September (primarily because of high demand charges in the summer). In contrast, residential ("domestic") customers generate nominally positive net revenues year-round.

Consequently, the phase-in strategy relied upon:

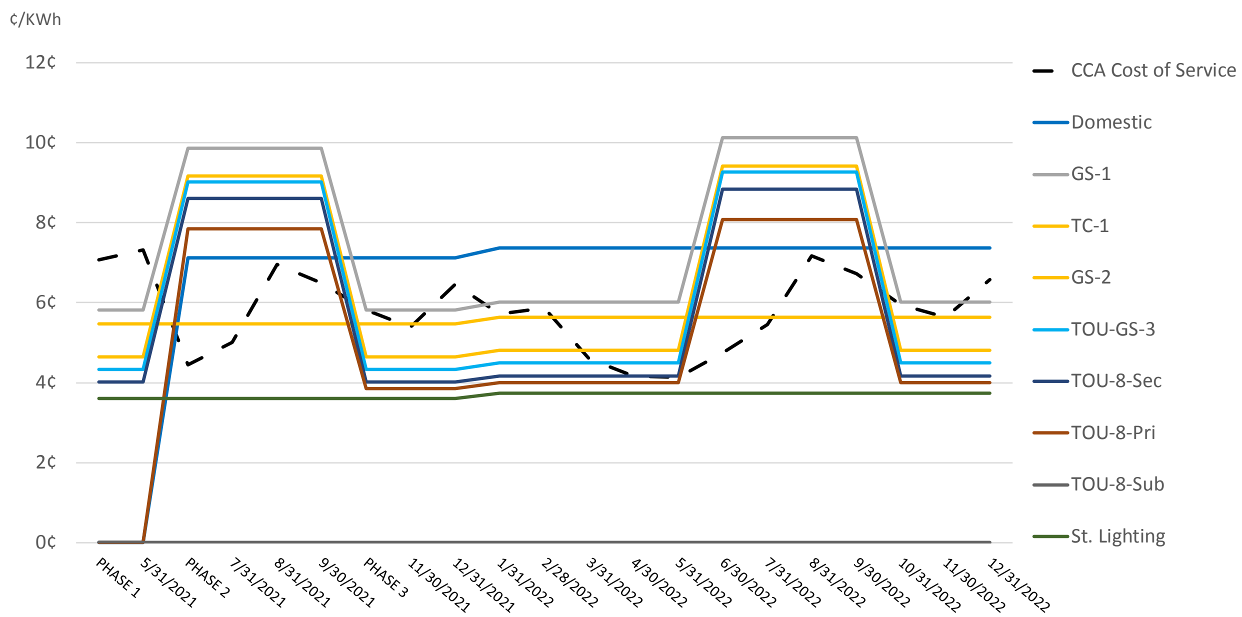
- Enrolls municipal accounts in April 2021;
- Enrolls nonresidential customers, and a small percentage of residential customers, in June 2021 maximize initial net revenues;
- Balances the winter decline in revenues by enrolling the remaining residential customer base in October 2021;
- The three charts which follow visualize these dynamics and their impact on the CCA over the three phase-in periods.

First, we can see when certain customer class rates are above or below the CCA's cost of service:

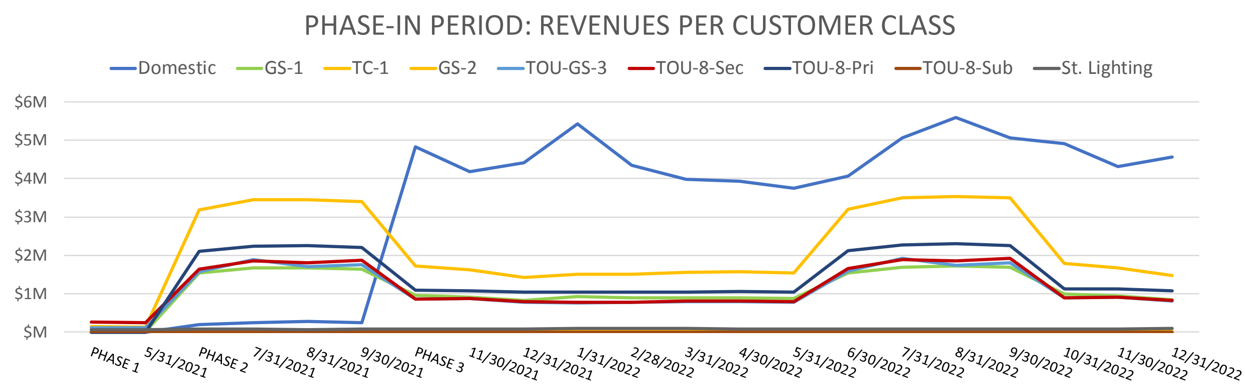
CUSTOMER ACCOUNTS BY ENROLLMENT PHASE

	Phase 1 APRIL 2021	Phase 2 JUNE 2021	Phase 3: OCT 2021	TOTAL (post opt-outs)
Domestic	-	8,064	153,222	166,923
GS-1	375	16,550	-	17,392
TC-1	596	-	-	596
GS-2	224	2,279	-	2,568
TOU-GS-3	28	177	-	210
TOU-8-Sec	21	45	-	67
TOU-8-Pri	-	42	-	43
TOU-8-Sub	-	-	-	-
Small AG	65	56	-	122
Large AG	4	9	-	13
St. Lighting	969	360	-	1,340
Standby - Sec	-	-	-	-
Standby - Pri	-	-	-	-
Total	**2,282**	**27,583**	**153,222**	**189,276**

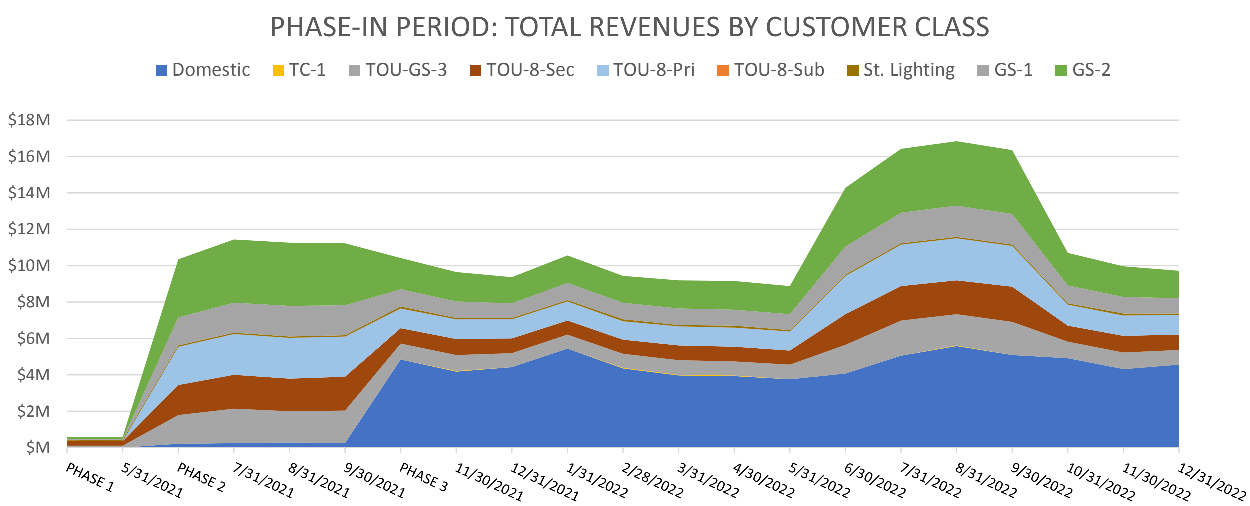
PHASE-IN PERIOD 'BREAK EVEN': CCA COST OF SERVICE vs. CUSTOMER CLASS RATES
(average rates include demand charges)



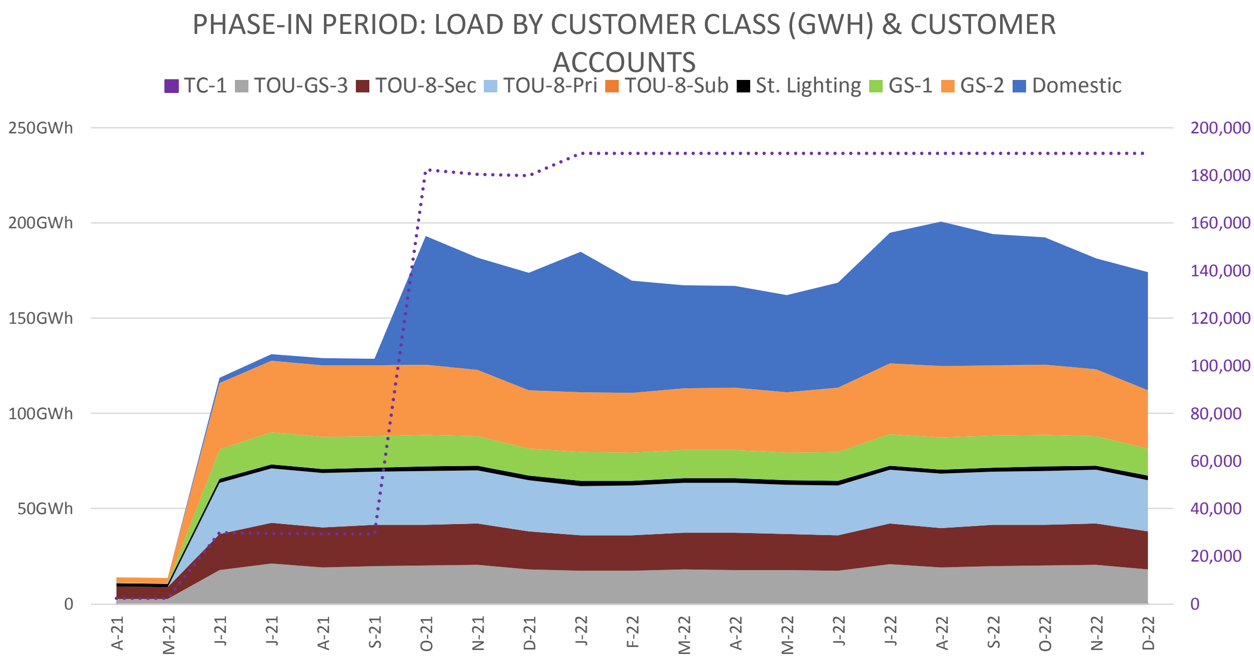
Next, note how the enrolling residential customers ("domestic", in blue) in the charts below provides substantial revenues as the other classes drop going into the off-season, and continue to do so the next year as well after the CCA is at full enrollment:



Consequently, total revenues for the CCA are maximized during Phase 2 enrollments, which diminishes the financing requirements for the subsequent Phase 3 enrollments:



This chart shows the three phase-in periods in terms of customer accounts and load volumes:

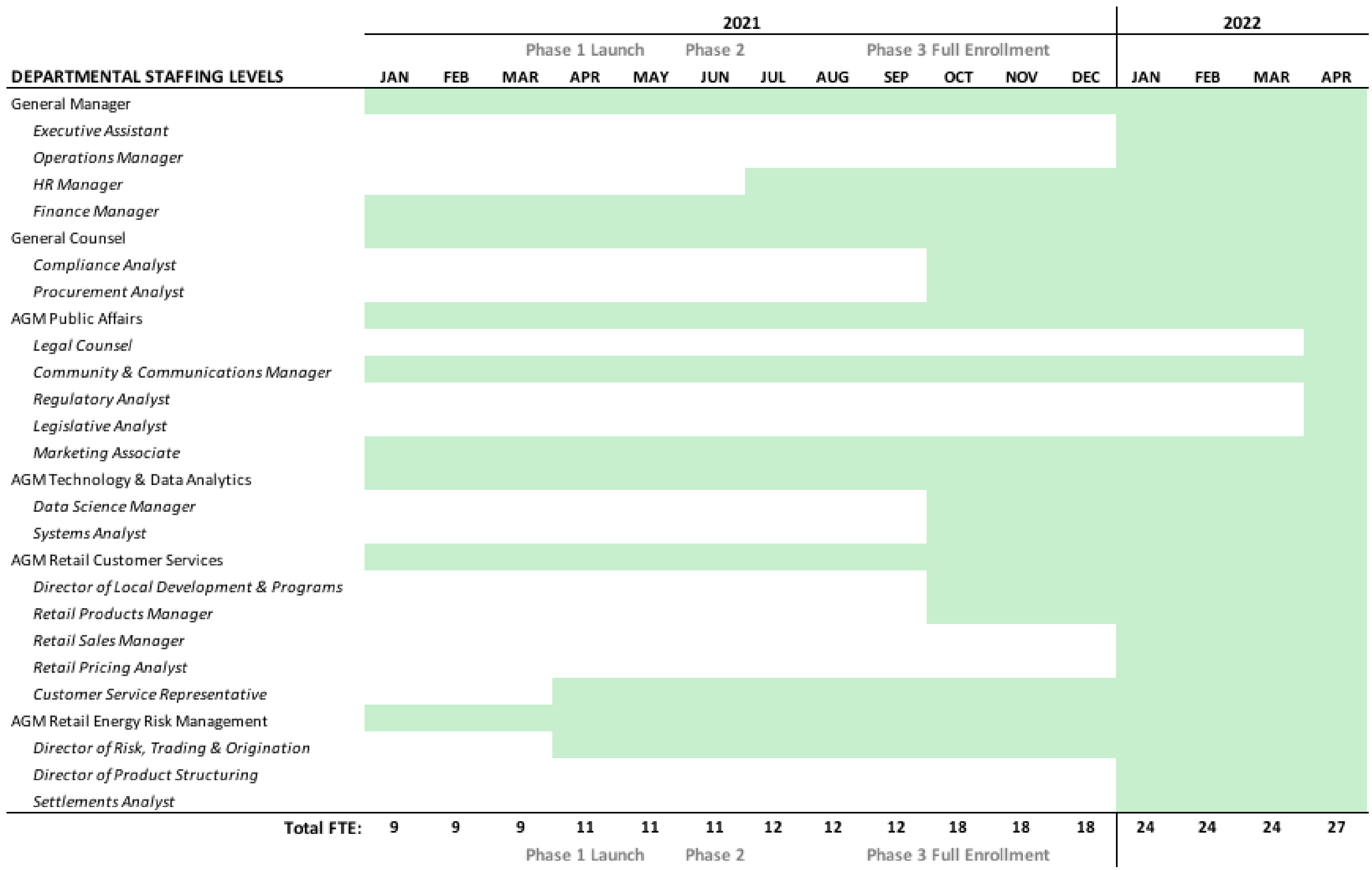


Staffing

The figure on the following page shows the development of internal capacity, in terms of agency staff levels and titles by department, during the first year of CCA operations:

These staffing levels are intended to provide the CCA with:

- Initially: sufficient oversight of third-party contractors providing operational and advisory services during the planning and initial customer phase-in stages;
  - Operational services provided by third-party contractors: Portfolio Management & Power Market Operations, Retail Data Management and Billing, and Customer Care and Call Center Operations;
  - Advisory services: Accounting and Audits, Marketing and Branding, Technical Consulting Services, HR, IT & Admin Support, Financial Advice, Regulatory Engagement & Legal Advice, and Legislative Advocacy.
- Subsequently: the foundational internal capacity necessary to continually evolve data management, risk management analytics, energy procurement, local development programs, as well as innovative retail rate structures and distributed energy resource integrations across all customer classes.


2021
2022
Phase 1 Launch
Phase 2
Phase 3 Full Enrollment
DEPARTMENTAL STAFFING LEVELS
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
APR
General Manager
Executive Assistant
Operations Manager
HR Manager
Finance Manager
General Counsel
Compliance Analyst
Procurement Analyst
AGM Public Affairs
Legal Counsel
Community & Communications Manager
Regulatory Analyst
Legislative Analyst
Marketing Associate
AGM Technology & Data Analytics
Data Science Manager
Systems Analyst
AGM Retail Customer Services
Director of Local Development & Programs
Retail Products Manager
Retail Sales Manager
Retail Pricing Analyst
Customer Service Representative
AGM Retail Energy Risk Management
Director of Risk, Trading & Origination
Director of Product Structuring
Settlements Analyst
Total FTE: 9 9 9 11 11 11 12 12 12 18 18 18 24 24 24 27
Phase 1 Launch
Phase 2
Phase 3 Full Enrollment

Chapter 6: Risks & Mitigating Strategies

As discussed so far, there are potential benefits to CCA formation, but there are also risks. This chapter lists many of the larger risks that a Long beach CCA would face—and in fact all CCAs must deal with—along with summaries of how the CCA can address the risk. If Long Beach were to pursue CCA formation, it should create a risk management plan that would flesh out more specific risk policies and proceedings. The basic content of a risk management plan is included in Appendix 2.

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 Long Beach joined a JPA-governed CCA, the formation documents for the CCA define the rights and responsibilities of each member of the CCA. Similarly, the JPA's books are completely separate from any of their member cities, and thus isolates the city from any CCA liabilities.

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. 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 form their CCA.[40] If there are negative communications to Long 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 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

[40] The exception to this is the large industrial customers in CPA's CCA. CPA chose not to offer competitive rates to these customers as the CCA could not cover their cost to serve them. The large opt-out, over 50%, was not unexpected and was planned for.

addition, prudent power procurement strategies will allow for a reasonable uncertainty in load, especially that associated with DA expansion, without having to either dump power at a loss or purchase excessive amounts at high spot market prices. CCAs also may be able to 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 objective is to offer power to Long Beach residents and businesses are a competitive price relative to SCE. In this circumstance, competitiveness is tied to the rate offered by SCE. A number of factors can cause Long Beach CCA's net power costs to exceed SCE. Long Beach CCA 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 to be less than Long Beach CCAs. Assuming that SCE's rates are based on its cost of service, Long Beach CCA obviously has little or no ability to influence the rates that SCE offers.

Mitigation: While Long Beach CCA has little ability to affect SCE's generation rates, it will 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 a Long Beach CCA customer to realize an economic benefit (i.e., pay the same or less for electricity), the sum of the Long Beach CCA 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 Long Beach CCA customers, it will be necessary for Long Beach CCA 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 such 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 requirement has been simply the equal to a 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 occur in 2020 due to the limited expansion of the DA cap from SB 327. Additional expansions are possible, if not likely.

***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 that 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.

Energy Risk Management

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. Those risks are listed below.

- Net Revenue
- Market Price
- Volume
- Temporal
- Basis

- Counterparty Credit
- Counterparty Performance
- Liquidity
- Operational

To mitigate risk, 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. A detailed discussion of how procurement risk is managed by CCAs is shown in Appendix 2: CCA Energy Risk Management. CCA Risk Management plans can be found on their respective websites.[41]

Elements of Risk to a Community Choice Aggregation Load Serving Entity

Net Revenue. Net revenue risk is the likelihood that revenue received from retail customers and sale of surplus energy is less than the cost of procuring energy on behalf of those retail customers. Those costs include forward supply purchases, new development of generation facilities, purchase of energy in the CAISO day-ahead and real-time markets and ancillary products such as Resource Adequacy, Renewable Energy Credits, carbon-free products and CAISO ancillary services and administrative costs.

A major component to the cost side of the Net Revenue equation is the Power Charge Indifference Adjustment (PCIA) that the incumbent utility charges all load that it no longer serves. The rationale is that the incumbent utility planned for those customers so they should pay a fee to reimburse the utility for those purchases. The higher the PCIA the higher the cost the CCA incurs.

Market Price. Market price risk is the CCA's exposure to spot market prices that it pays in the California Independent System Operator's (CAISO) markets to serve its load.

Energy that is supplied by the CCA on behalf of its retail customers is procured in its entirety from the CAISO's day-ahead and real-time markets every day for each of the 24 hours in a day. The energy from the CAISO's market is from energy suppliers that offer the CAISO energy every day for each of the 24 hours in a day. The result is the CCA purchases its expected energy from the CAISO at the CAISO's hourly day-ahead market clearing prices and residual energy based on meter reads from the CAISO's real-time market. Those clearing prices vary hour-to-hour in the day-ahead market and every 15 minutes and 5 minutes in the real-time markets depending upon factors such as time-of-day, time-of-year, availability of supply, natural gas prices and transmission equipment outages.

Although the CCA procures all of its load from the CAISO market, the CCA will mitigate the risk of buying energy at the CAISO's constantly changing market clearing prices by obtaining supply and selling energy from those suppliers into the CAISO market. In that way although the

[41] 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.

CCA is exposed to market prices for purchasing energy from the CAISO, it receives market prices for selling energy supply into the CAISO's markets. The result is that market price exposure is only for the amount of load that is not hedged with off-setting supply or some other product.

Volume. Forecasting customer usage against what is actually consumed affects procurement. Over-forecast of customer usage results in over-procurement and the need to resell excess energy at a cost that is different than what it bought at. Under-forecast results in under-procurement and reliance on default energy purchases from the CAISO's markets.

Factors that affect energy forecasts are categorized into long-term fundamentals and short-term transitory. Long-term fundamental factors include:

- Customers that decide to opt-out
- Behind-the-meter installations of generation, typically roof-top solar panels for residential customers and larger steam-recapture or other qualifying facility type of generators for larger industrial customers
- Changes in customers' business such as expansion, contraction or shutting down entirely
- Energy efficiency installations
- Electric vehicle charging
- Inherent limitations to modeling customer load and accuracy

Short-term transitory factors include:

- Weather
- Short-term maintenance
- Production ramp ups
- Events such as festivals and other activities
- Inherent limitations to forecasting weather and customer load

Long-term fundamental factors affect mid-term and long-term procurement (ranging from one month to multiple years). It is fundamental because it indicates a behavioral change or choice that affect load more permanently as opposed to a transitory change that is short-term due to weather or maintenance outages.

Temporal. Temporal risk is the difference between the customer load profile (energy amount and time when energy is consumed) and supply profile (energy amount and time when energy is produced) that is acquired by the CCA to serve its load.

If the supply and load volumes are identical and delivery of supply coincides with when customers consume energy, the CCA's risk to market prices is mitigated (ignoring for now, basis risk that is described in the next section). This is because whatever the CCA has to pay for its load at CAISO market prices, the supply that the CCA sells to the CAISO market will receive the same CAISO market clearing prices (again, ignoring basis risk).

However, most energy supplies are independent and not correlated with customer load. For example, solar energy is produced between 6 AM and 7 PM depending upon time of year.

Customers consume energy 24-hours per day. That means that 1,000 MWh of solar energy does not match 1,000 MWh of customer load. And because prices vary hour-to-hour, the value of the solar energy produced will be different than the cost of energy consumed by customers.

Basis. Basis risk is the difference in location between where energy is supplied onto the CAISO's grid and where energy is consumed from the CAISO's grid. The CAISO's market energy prices are nodal-based and therefore location-specific. Nodes are electric substations, generating facilities and interconnections to neighboring out-of-state and in-state utilities. Each of these locations has its own nodal price that varies based on congestion (too much energy flowing through a transmission line or other type of equipment) and energy losses. The more valuable nodes, that is locations where the grid most needs energy to reduce or eliminate congestion and losses, the higher priced the node.

Loads are aggregated into a single point called a DLAP (Distributed Load Aggregation Point). Supply nodes are individual nodes. Because the CAISO markets are designed to minimize costs to consumers, and the most efficient way to do that is to locate supply near load, the DLAP prices are typically higher than the supply nodes. The difference between these supply and DLAP prices is basis risk.

Counterparty Credit. Counterparty credit risk is the likelihood that a counterparty to a transaction could default before the final settlement of the transaction. The more highly rated the counterparty, the less likely it is to default. Counterparties that do not have credit ratings could provide a parental guarantee if it is a subsidiary of a larger entity. It could also provide collateral as protection to the CCA.

Counterparty Performance. Counterparty performance risk when the CCA is selling to a purchaser stems from not receiving payment from the purchaser.

The risk when the CCA is buying from a supplier occurs when market prices increase after the CCA purchases a product. That means the product is more valuable to the market rather than under its contract. The CCA's risk is if the supplier should default and is no longer able to provide the supply, the CCA would then have to go to the market to procure a new source of supply at a higher price.

For example, a CCA has procured 10,000 MWh of energy from a supplier at $40/MWh for delivery beginning in 2021 for a total cost of $400,000. If the market price moves to $50/MWh and the supplier cannot deliver the 10,000 MWh of energy in 2021, then the CCA will have to go to the market to procure a replacement for 10,000 MWh at $50/MWh for a total cost of $500,000, an increase in cost of $10,000 to the CCA.

Liquidity. Liquidity risk is defined as a cash shortfall whereby an CCA does not have the cash available for making payments to its suppliers in a timely fashion. This could occur during start-up when starting from a net revenue position of zero and incurring start-up costs in addition to steady-state operating costs. It can also occur when customer revenue forecasts fall short of expectations and/or costs are above expectations. A fundamental shift in market conditions or an event that drives prices or energy consumption could also affect net revenue and resultant liquidity.

Operational. Operational risk affects the CCA's costs and revenue if operations are not implemented efficiently and accurately. And because there are numerous data handoffs and dollar flow exchanges among the CCA, the incumbent utility, the CAISO, retail customers and wholesale energy suppliers, there is a need to ensure that processes are well understood and monitored.

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 California Air Resources Board (CARB) is regulates emissions.

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

- Direct Access
- Resource Adequacy[42]
- Power Charge Indifference Adjustment
- Renewable Energy Purchase Requirement
- Power Content Label Reporting
- Central Procurement Entity
- Energy Provider of Last Resort (POLR)

[42] 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.

These include procuring sufficient resource adequacy capacity of the proper type and meeting RPS requirements that are evolving.[43] Additional rules and requirements might be established. These could affect the bottom line of the CCA.

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

Political Risk

Any major decision made by the city Council carries with it political risk. If the CCA go well, it will could go unnoticed by most residents and businesses. If things go upside down, the blame and accountability will be directed at the elected officials.

In addition, Long Beach has a long relationship between SCE; it is the largest city served by SCE. While there have been occasional bumps in the relationship road, there is not the acrimony directed at SCE as there is in Northern California at PG&E. If Long Beach forms a CCA there is a possibility that certain relationships the City enjoys with SCE/Edison International may dissipate.

[43] Rules to establish RPS requirements under the new 50% RPS mandate are currently being debated at the CPUC.

Chapter 7. Macroeconomic Impacts

This chapter describes how establishment and operation of a CCA will affect the economy of Long Beach over the period from 2021 to 2030. **It is based on Supply Scenario 1 and assumes that the CCA is not serving the TOU-8 subtransmission customers. Further, it assumes half of the margin in each year goes towards rate savings.**

Overview: How a CCA Will Affect the Local Economy

Types of Impacts. In general, effects occur via three mechanisms:

1) *Direct CCA Administration and Operation Spending.* This includes spending for staffing, supporting office equipment and professional-technical services and I/T-database services. Setup is a short-term effect, while continuing operations is a long-term effect.
2) *Direct Effect on Energy Bill Savings*. Costs savings provides local households with additional money to spend on local consumer goods and services. It provides local commercial and industrial energy customers with a reduction in their "cost of doing business" which makes them competitive for serving wider markets. That enables them to grow further and increase employment. Municipal energy customers can provide more local services with the money saved. These impacts grow over the long-term.
3) *Indirect and Induced Economic Impacts.* The above (1,2) effects will directly grow local economic activity and that will lead to further purchases from local suppliers of materials and services (referred to as "indirect effects"). It will also lead to re-spending of the additional worker wages on consumer purchases in the community (referred to as "induced effects").

These three effects occur over time. There is also a spatial component because the economy of Long Beach can indirectly benefit from spillover impacts on supplier activities in surrounding parts of Los Angeles County or adjacent Orange County. All of these various impact elements are covered in this report.

Analysis Methodology. In the pages which follow, we explain how the direct spending effect on Long Beach is calculated on the basis of the expected CCA budget, and how the direct energy cost savings for Long Beach customers is calculated on the basis of expected change in energy rates and customer energy use. The underlying factors that are the basis for these calculations are derived from energy scenarios and financial analyses in prior chapters.

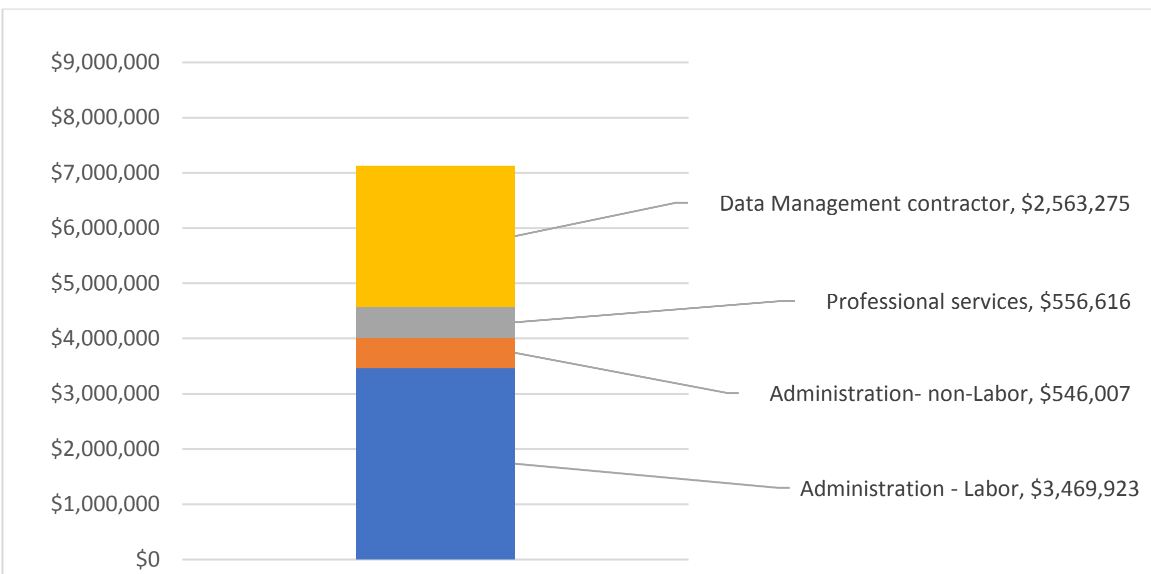
To calculate the indirect and induced economic consequences, a multi-regional input-output (I-O) economic model was used representing the economy of Long Beach and its interactions with the rest of Los Angeles County and adjoining Orange Counties. An I-O model is an accounting system that shows how each type of industry/organization buys and sells products and services from other industries. It also shows the extent to which the inter-industry purchases and sales occur within the study area or occur as flows of money to and from industries located outside of the study area. This kind of accounting system makes it possible to calculate expected indirect and induced economic effects that occur as a consequence of direct changes in spending and income among local industries. The economic modeling process also included estimates of how rate changes would affect the economic competitiveness and growth of local industries.

Spending Impacts from CCA Administration and Operations

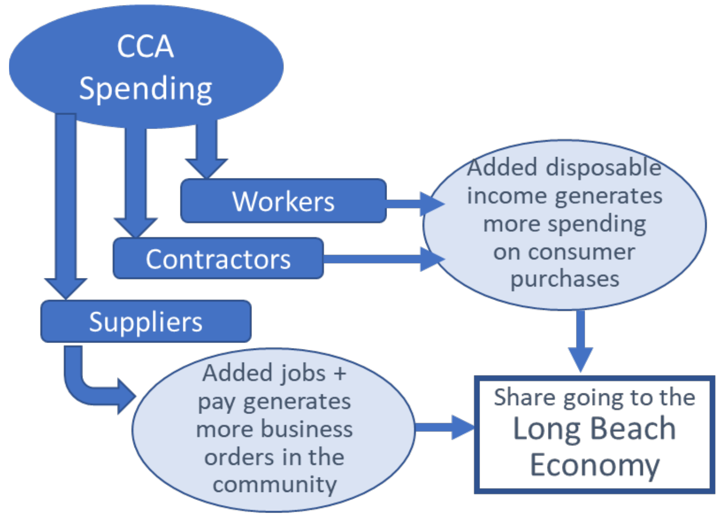
The setup and operation of a CCA comes at a cost, which is reflected in the rate impact calculations. However, the money is spent on employing local workers and purchases of materials and support services, some of which are also locally located. The spending thus creates jobs and income in the local economy. This section explains the spending impact.

Over the long-term, there will be continuing operation with a staff assumed to be approximately 26 employees plus contractors, with an annual operating budget averaging $7.1 million/year. That budget will grow with inflation over time, from $5.4 million in 2021 to $8.0 million by 2030. Figure 21 shows a breakdown of the average year expenditures including administration, office operations and purchases of professional services and data management from contractors. These activities will generate additional income within the economy of Long Beach and surrounding areas. There are other costs associated with energy purchases in later years, including payoff of startup loans and SCE exit fees that will affect CCA operating costs and energy rates, but they will not directly affect the local economy.

Figure 21. Expected Breakdown of 2021-2030 Annual Average Spending for CCA Operation



Economic Impact of CCA Operation Spending. The $7.1 million of average year CCA spending (from Figure 21) will go into the pockets of workers, suppliers and contractors, of whom some but not all will be located in Long Beach. These money flows are illustrated in the graphic below.



To calculate the economic impact of these money flows for Long Beach, we utilized the IMPLAN input-output economic model. The model calculated the portion of direct CCA spending that will represent income to local workers and revenue for local product and service suppliers. This represents the "direct effect." Specifically, the $3.5 million of CCA administration labor budget (from Figure 22) was presumed to go for jobs located in Long Beach, although an estimated 36% of that money will be spent outside of Long Beach. Of the other CCA spending, it was also assumed that most of the professional service and supplier money, but only a small share of the data management spending, will generate income in Long Beach.

Altogether, Table 15, column 1 shows a that the expected direct spending effect on business revenue in Long Beach ($4.7 million per year) will be significant, though less than the ($7.1 million/year) amount of total annual CCA budget. However, this direct spending effect also leads to additional local economic impacts explained below.

The economic model calculated how direct purchases of supplies and staff salaries will recirculate in the economy, leading to further "indirect" (supplier) impacts and "induced" (worker wage re-spending) impacts. The total of direct, indirect and induced impacts is shown in column 2. The results indicated a total impact on annual worker income in the city ($5.2 million/year) that is larger than the direct worker income impact ($3.8 million per year). The model results also show that the CCA budget spending will ultimately lead to a total average impact of $8.3 million per year of business revenue in Long Beach.

Table 15. Impact of CCA Operations Spending, 2021-2030 Annual Average

	Annual Operations: 2021-2030 (average)	
Impact Measure	**Direct**	**City Total**
Jobs	28	43
Total Wages Paid ($ millions)	$3.8	$5.2
Total GRP (Value Added, $ millions)	$4.2	$7.1
Total Business Output (revenue, $ millions)	$4.7	$8.3

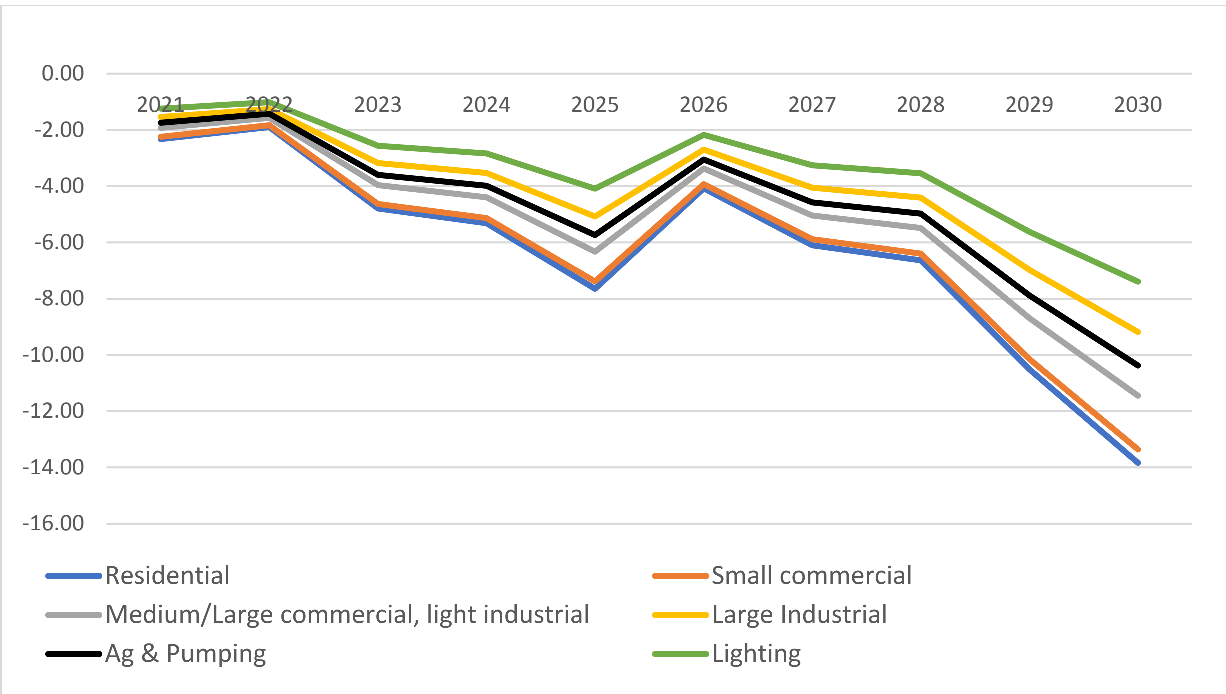
Note that in this table, "output" represents total business sales (revenues) occurring in the study area. "GRP" is gross regional product, which is the portion of output that represents income to workers and net income to businesses. "Wages" represent the portion of GRP going to pay workers.

Energy Bill Savings Impacts

To calculate the value of anticipated energy bill savings, we utilized information from prior chapters that calculate the expected rate reduction by rate class, and then multiplied it by the expected energy load occurring in each rate class. The expected savings in energy costs will be distributed across different rate classes and will affect the economy in different ways that are explained in the discussion of economic implications.

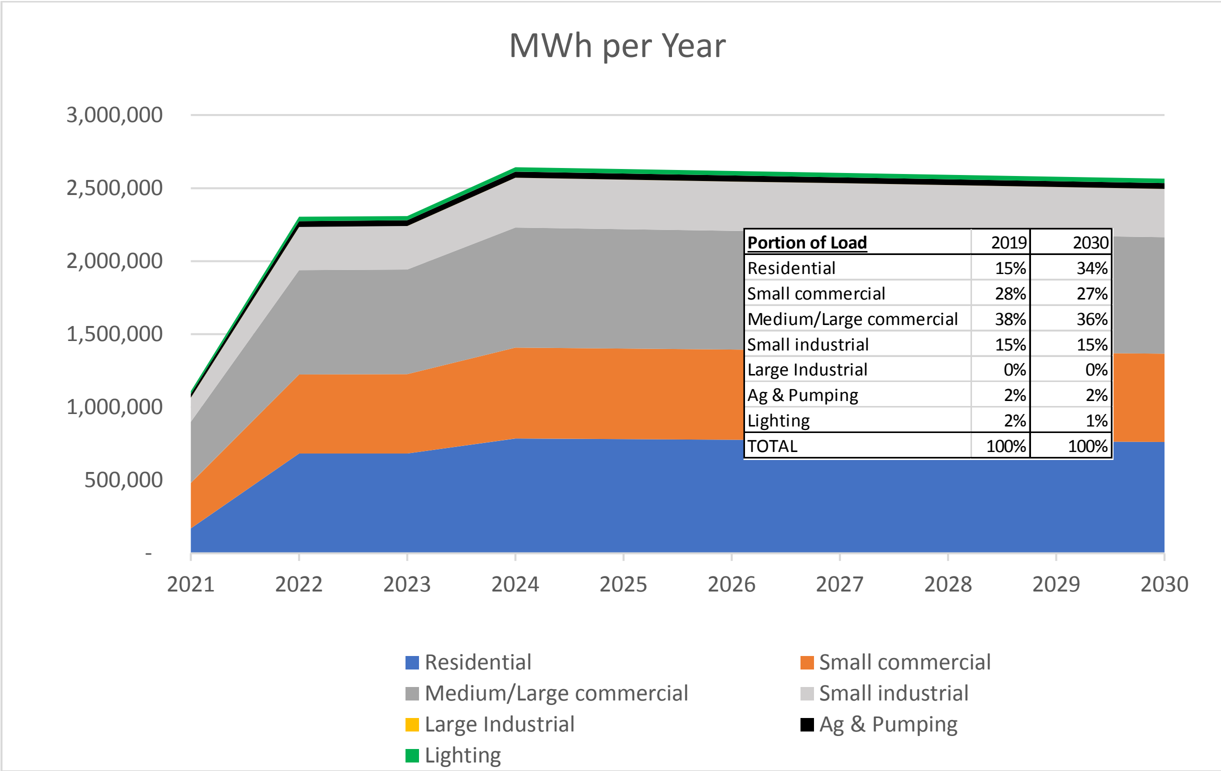
Calculation of Energy Bill Savings. Figure 22 shows the expected average rate reduction by rate class. These rate reductions are not guaranteed but are based on Supply Scenario 1, using one-half of the annual margins from that scenario, and a further assumption that the CCA is not serving TOU-8 subtransmission customers.

Figure 22. Average Rate Reduction (dollars per MWh) by year and rate class



The rate reduction applies to Long Beach CCA electric customers. Figure 23 shows the assumed projection of CCA energy consumption by customer rate class. It shows load growth in early years for all sectors, but particularly the residential sector. Total annual energy consumption is projected to be around 2.5 million MWh over the 2024-2030 period.

Figure 23. Energy Consumption Projection (MWh)



The total expected energy bill savings for Long Beach electricity customers is the product of the expected rate reduction multiplied by the expected level of consumption. So, for instance, the expected average rate savings in 2025 is roughly $6/MWh (Figure 22) and the expected consumption in that year is roughly 2.5 million MWh (Figure 23). Hence the total expected cost savings for that year is $6/MWh x 2.5 million MWh = $15 million.

The cost savings will vary over time. Figure 24 shows that the savings increases from roughly $2 million per year in the first year (2021) to over $26 million per year by 2030. There is a blip in 2026-2027 due to debt payments on startup costs. The average energy bill savings for the 10-year period is actually $12.1 million per year.

Figure 25 shows the breakdown of cost savings by customer rate class for an average year. It shows that of the roughly $12.1 million in bill savings for an average year, 33% of the savings will be for residential customers, 25% will be small commercial customers, 29% will be medium/large commercial customers and 12% will be small industrial customers. Street lighting and agriculture account for the remainder.

Figure 24. Annual Energy Bill Savings for Long Beach Electricity Customers ($ millions)

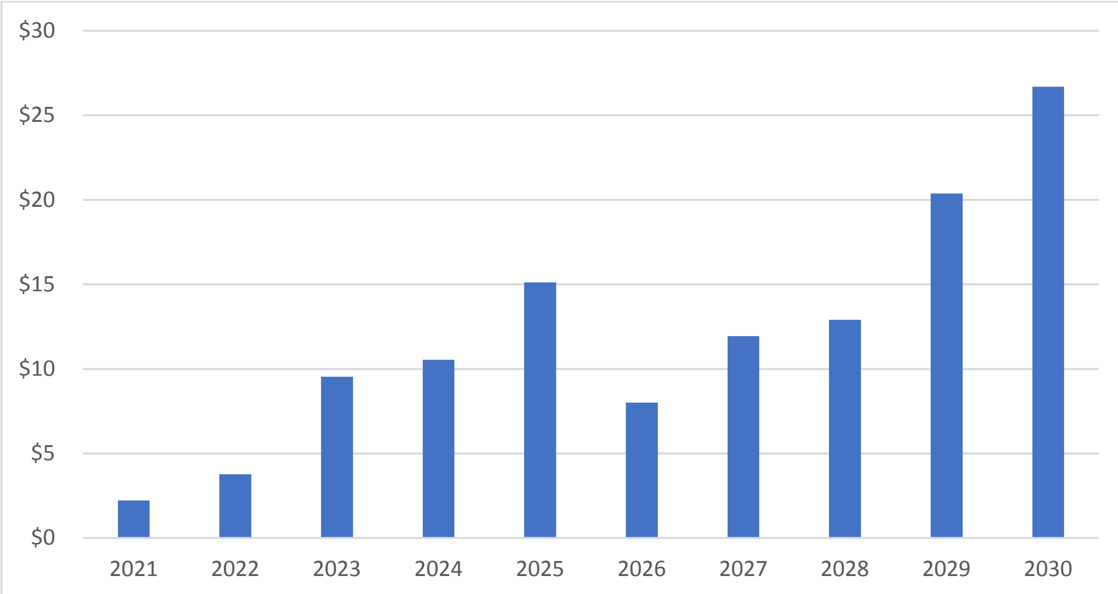
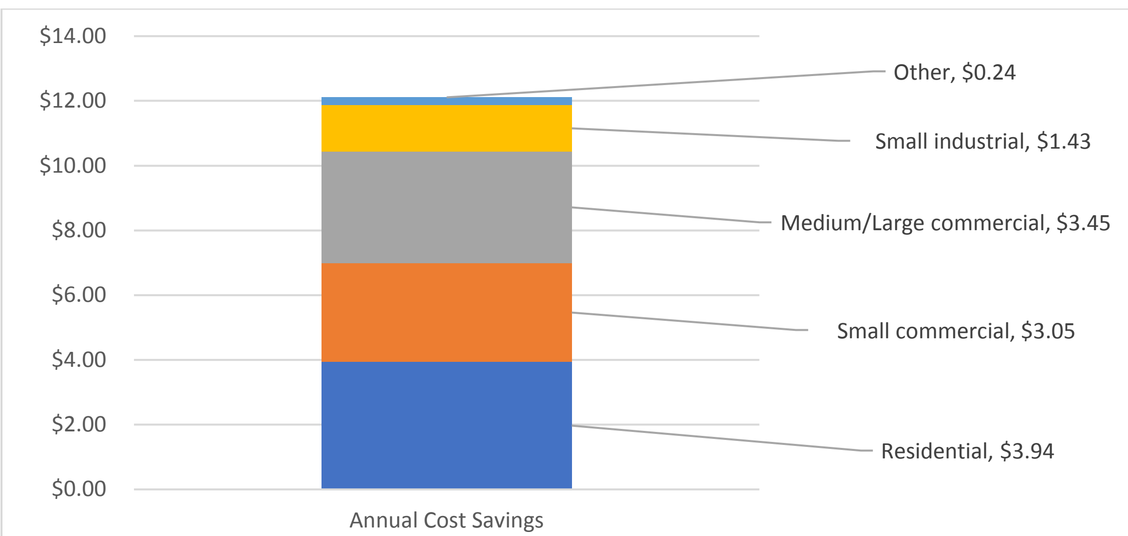


Figure 25. Composition of Annual Average Energy Bill Savings, by Rate Class ($ millions)



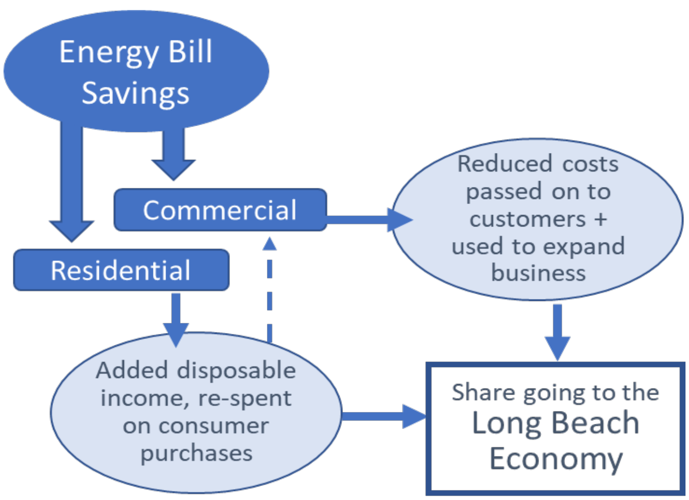
Economic Impact of Energy Bill Savings. The expected energy bill savings will enable both additional consumer spending and business productivity benefits in the local economy. In the economic model, cost savings generate the following impacts:

- Energy bill cost savings for residential energy customers becomes added disposable income for Long Beach residents, and that generates additional local consumer spending.

- Energy bill cost savings for commercial energy customers represent added business income and increases business productivity. Commercial businesses typically pass on added net income in the form of lower prices for customers (thus increasing disposable household income) as well as added investment in expansion to create more jobs. Either way, the cost savings can increase money available to be re-spent in the community.

- Savings for industrial customers enables that sectors of the economy to be more cost-competitive in serving broader markets beyond the local community. However, Long Beach does not have large industrial activity so the competitiveness effect will be muted.

These money flows are captured by the economic model and are illustrated in the graphic to the right. Some but not all of the money will flow to Long Beach businesses. That direct effect, in turn, will lead to further "indirect" effects on sales for local product/ service suppliers as well as "induced" effects of worker wage re-spending.



Total impacts on the growth of Long Beach's economy are shown in Table 16 below. Actual impacts will vary by year, reflecting differences in consumption as shown earlier in Figure 24.

Table 16. Impact of Energy Bill Savings, Annual Average: 2021-2030

Effect of Energy Bill Savings	City Total
Jobs	143
Wages ($ millions)	$8.6
GRP (Value Added) ($ millions)	$13.8
Output ($ millions)	$21.0

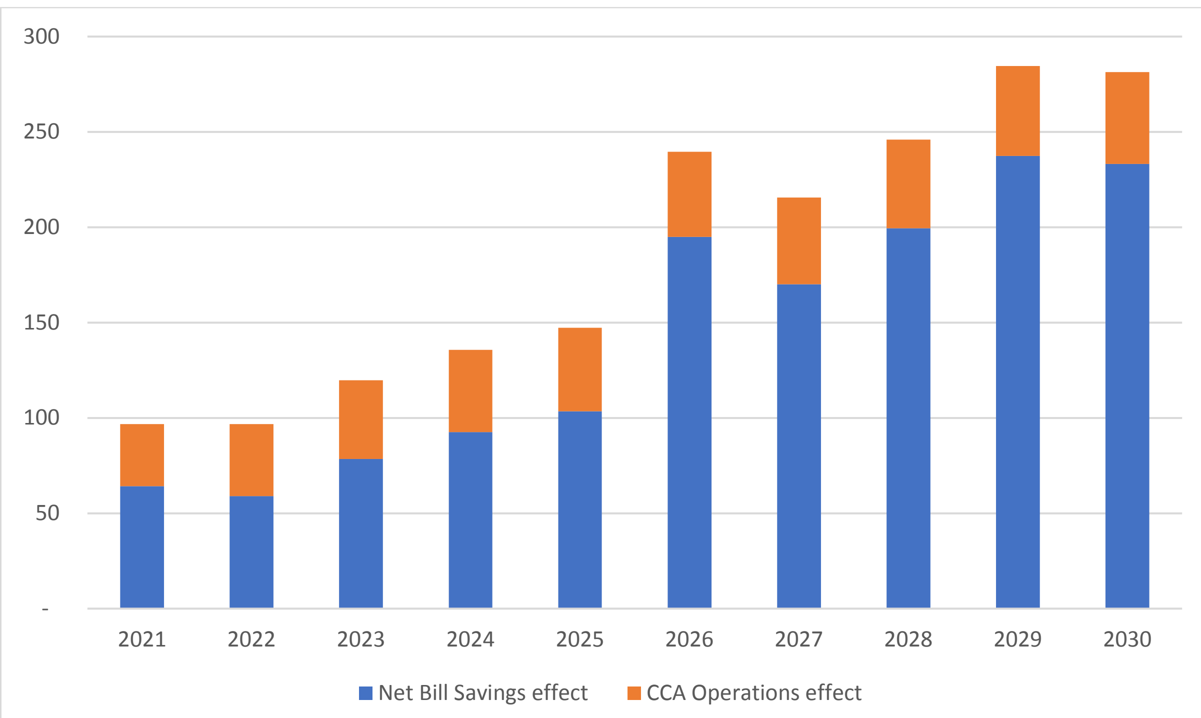
Overall Impacts on Jobs and Economic Growth

The overall economic impact of the CCA represents the combined effect of CCA operations spending, energy cost savings and their additional indirect and induced economic impacts. Table 17 and Figure 26 show how each of these elements contributes to the overall economic impact over time. It shows that energy bill savings will be the main source of impact on the local economy, though the CCA operations spending will also contribute to local economic activity.

Table 17. Total Economic Impact on City of Long Beach (2021-2030 Annual Average)

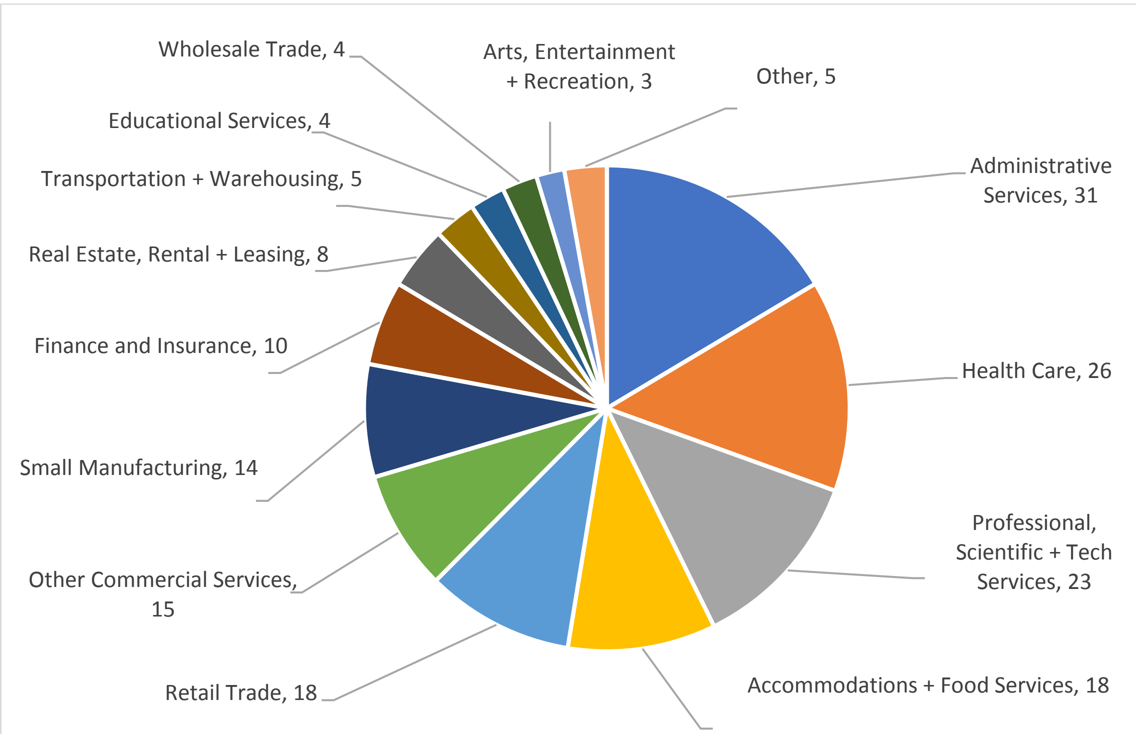
Source of Impact	Jobs	Wages ($ millions)	GRP ($ millions)	Output ($millions)
CCA Operations Spending	43	$5.2	$7.1	$8.3
Energy Cost Savings	143	$8.6	$13.8	$21.0
TOTAL	186	$13.8	$20.9	$29.3

Figure 26. Long Beach Job Impacts by Source and Year



Job Impacts by Industry Sector. The economic impact of CCA operation and associated energy bill savings will be distributed widely across all sectors of the Long Beach economy, as shown in Figure 27. Some are industries that will benefit from increased consumer spending; others are regional product and service providers who will gain from increased cost-competitiveness. Among the jobs listed here, the average wage is $102,120/year.

Figure 27. Mix of Benefitting Industries, Annual Average Job Impact



Chapter 8. Overview of Power Agency Design & Implementation Process Options

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, formulation of financial and debt policies, and 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 in as an enterprise. Enterprise 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 separate 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 Long Beach CCA 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 communication 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 Long 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 Long Beach 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 Long Beach departments.

All larger CCA have dedicated staffs of 15 – 40 employees. The closest analog to Long Beach is San Jose Clean Energy (SJCE). SJCE is the only larger city with an enterprise CCA. Its planning documents show an eventual staff of 20.

Forming 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. 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 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, for instance 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.

A quantitative analysis of whether a JPA would benefit or reduce the financial prospects of the CCA, based upon the addition of specific agencies and their associated energy load, is beyond the scope of this report. Additional analysis would be necessary to determine if adding the load of other agencies to the load served by the Long Beach CCA would create different demand patterns and peaks, or compound existing peaks, either of which might adversely impact Long Beach CCA customers, or the customers of the other prospective JPA members.

A standard JPA would be possible for the City, but it would require joining with at least one other jurisdiction. This could include one of the neighboring cities who has already formed a CCA or are also considering CCA, such as Irvine and Huntington Beach. If this option is to be pursued, discussions with potential partners would need to begin.

Joining an Existing Joint Powers Agency (Clean Power Alliance)

Long Beach has been offered to become a member of the CPA, the CCA that serves unincorporated Los Angeles and Ventura Counties along with 29 municipalities within those counties. CPA was formed in 2017 and rolled out service to its customers in 2018 and 2019. It is by far the largest CCA in the state, projected to provide over 10,000 GWhs (10 billion kWhs) in 2020. This will place CPA in the top 70 electric utilities by sales in the US (by load).[44] Were Long Beach to join, its load could increase to over 13,000 GWh, placing it within the top 50 electric utilities in the country.

CPA is governed by a board of directors with one voting member per jurisdiction. Votes are tallied on an equal basis, one vote per jurisdiction, no matter its size. After an affirmative vote, three directors may call for a volt based on load share. In that case, 50% of the weighted voted share would be needed to carry the item.[45]

CPA offers 3 tiers of service, differentiated by renewable content and price: 36% renewable at a modest price savings relative to SCE; 50% renewable at the same price as SCE, and 100% renewable at a price premium relative to standard SCE service. Each member jurisdiction may to select the service tier in which to default its residents and businesses. For example, communities such as Santa Monica have chosen to default its residents and businesses into the 100% Green tier. Santa Monica residents need not remain on that tier—they may affirmatively select another tier, but if they take no action, they are placed in the 100% green tier, albeit at a price that exceeds the standard (less green) SCE option. The city of Hawthorne, on the other hand, defaults

[44] Based on 2017 sales, per EIA. https://www.eia.gov/electricity/sales_revenue_price/
[45] JPA agreement, section 4.10.3

its residents and businesses into the lower cost "lean" tier, while allowing them to affirmatively choose the either of the more costly, but less emitting, other tiers.

The general benefits and drawbacks discussed above about JPA formation apply to Long Beach joining CPA. It would need to weight the benefits of joining an ongoing concern, with management and governance structures in place, versus the flexibly of forming a city Enterprise or entering into a new JPA.

To Join CPA, the City would have to pass an ordinance requesting membership.

Joining the California Choice Energy Authority

The California Choice Energy Authority (CCEA) is a new form of CCA JPA, where the JPA provides requested services to its member CCAs but does not control any of its general policies or programs. More specifically, the CCEA provides its member jurisdictions, as desired:

- Power, including contract procurement, portfolio management, load forecasting and scheduling, and complying with and demonstrating procurement-related regulatory requirements (e.g., resource adequacy, renewables, etc.).
- Regulatory and compliance support, including needed preparing and filing compliance reports to the California Public Utilities Commission, the California Energy Commission, and the California Independent System Operator; and general regulatory advocacy.
- Billing and data management, including interface with SCE and call center operations.
- Treasury, including CAISO invoice validation, rate design development and risk management.

The City would be responsible for setting policies, setting rates, marketing and customer outreach, and the implementation of any desired local programs.

The CCEA Board of Directors is the Lancaster City Council. The actual services provided by CCEA are via contractors and consultants supervised by City of Lancaster personnel (e.g., Lancaster City Manager, Lancaster Choice Energy's Executive Director.) Thus, CCEA's administrative simplicity (the City not having to acquire expertise or expert contractors) is a traded off against the fact that its member jurisdictions have to accept the contractors and service providers selected by CCEA. The bottom line is that CCEA is by design more of a client-contractor relationship than a standard collaborative JPA. It is also, by design, set up to serve smaller communities such as its current members who do not have the administrative expertise or desire to set up and operate a full CCA. Because the Long Beach would be significantly larger than rest of CCEA combined, it is not likely a good fit.

Financing

The CCA will need to evaluate the financing options available and the relative costs and benefits of each in consideration of the CCA's risk tolerance. Financing options include:

Direct Loan from City (startup): The City could loan funds from the General Fund for all or a portion of the start-up needs. The City would be secured by the CCA revenues once launched.

The City would likely assess a risk-appropriate rate for such a loan which is likely higher than the City earns for funds otherwise invested. This rate is estimated to be 4.0 percent to 6.0 percent per annum.

Collateral Arrangement from City (startup and ongoing): As an alternative to a direct loan from the City, the City could establish an escrow account to backstop a lender's exposure to the CCA. The City would agree to deposit funds in an interest-bearing escrow account which the lender could tap should the CCA revenues be insufficient to pay the lender directly.

Loan from a Financial Institution with Support (startup and ongoing): Another alternative to a direct loan from the City would be for the City to backstop a lender's exposure to the CCA via a letter of credit, loan guarantee, or other promissory. The financial institution would not call upon the City unless the CCA was unable to make payment.

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

Vendor Funding (ongoing): The City can pursue arrangements with its power suppliers to eliminate or reduce the need for or size of funding for the start-up and operations. This could come in many forms such as a "lockbox" approach with a power provider. That is, the revenues that SCE would collect on the CCA's behalf would first go into a secured "lockbox" account, from which the power suppliers would be directly paid. After the power providers are made whole, the remaining revenue would then flow the CCA.

Long-term bonds: Bond issuances may secure an adequate (large) pool of cash that could sustain the CCA for a significant period of time and provide a cushion for swings in demand and power prices. However, as a new entity, the CCA itself with no credit or business history would not likely about to issue debt. The City, using its own credit rating could in theory issue the bonds, but doing so would place the city's own credit rating at risk. Furthermore, a risk with bond issuance is it may result in the CCA incurring an unnecessarily high level of debt or a shortage of funds depending on the accuracy of the sales and power cost forecast. Bond issuances can also be expensive and the CCA could incur significant issuance/underwriting costs.

Short-term commercial paper (ongoing): Short-term commercial paper (less than nine months maturity typically) is usually not backed by any form of collateral and as such it is a form of unsecured debt—however only large entities with high-quality debt ratings will find issuers without having a much higher cost for the debt issue. The CCA is a new entity and does not have an established credit history or recognized debt rating and as such access to this instrument would be difficult without the backing of the City's General Fund.

Letters of credit (ongoing): These typically would be letters of credit required by the power producers/marketers, with the required level of extreme specificity and additional complexity and rigidity associated with these instruments. Typically, a letter of credit is issued by the entity's existing Banker; as a new entity the CCA would need to explore this option with their potential Banker(s), and/or have the letter backed by the City's General Fund.

The City of San Jose's CCA (SJCE) is similar in size to a Long Beach CCA. SJCE's initial capital requirement will be provided from the City budget and via conventional financing methods (e.g., bank loans or lines of credit). Subsumed in the initial capital requirement is SJCE's initial start-up funding (up to $7.5 million), plus capitalized interest and fees on startup funding, which will be provided by the City of San Jose through the issuance of Commercial Paper and will be repaid by from the working capital financing. For the working capital financing, SJCE will make repayments (including any interest, as applicable) over an assumed 5-year term. SJCE will recover the principal and interest costs associated with the initial funding via retail generation rates charged by SJCE to its customers. It is anticipated that the initial working capital financing will be fully recovered through such customer generation rates within the first several years of operations.

Table 18. Financing Used by Other CCAs

Forms of Support		
CCA Name	Pre-Launch Funding Requirement[1]	Funding Sources
Marin Clean Energy	$2- $5 million	Startup loan from the County of Marin, individual investors, and local community bank loan.
Sonoma Clean Power	$4 - $6 million	Loan from Sonoma County Water Authority as well as loans from a local community bank secured by a Sonoma County General Fund guarantee.
CleanPowerSF	~$5 million	Appropriations from the Hetch Hetchy reserve (SFPUC).
Lancaster Choice Energy	~$2 million	Loan from the City of Lancaster General Fund.
Peninsula Clean Energy	$10 - $12 million	PCE has also obtained a $12 million loan with Barclay and almost $9 million with the County of San Mateo for start-up costs and collateral.
Silicon Valley Clean Energy[2]	$2.7 million	Loans from County of Santa Clara and City members $21 million Line of Credit with $2 million guarantee, otherwise no collateral,

Chapter 9. Start-Up Schedule and Milestones

This section discusses phase-in options for the Long Beach CCA, presents a general overview of the main implementation requirements for establishing a CCA and discusses the main parties with which the CCA interacts, set up requirements, and CCA structure.

General Implementation Schedule

An implementation timeline for a CCA startup in 2021 shown in Table 19. The overall schedule is driven by CPUC requirements, which are shown in the second column.[46] While there are number of CPUC requirements for a new CCA, the factors driving the launch of the CCA are: submitting implementation plan for CPUC approval one year prior to launch; meeting the RA requirement filing requirements throughout the year prior to launch; and meeting the customer notification requirements 90 days before launch. The detailed CPUC process is also discussed in the following section.

Through both legislation and regulation, SCE is required to work cooperatively with a CCA during exploration, implementation, and operation of the CCA. During operation, SCE will provide electricity meter data to the CCA, bill customers, and remit customer payments back to the CCA. SCE is also required to include customer notices with the utility billing statements on a cost basis for the CCA. Some CCAs in CA did not use utility billing statement inserts opting instead to use direct-mail notices providing requisite information about enrollment and opt-out.

Prior to launch, the electronic communications between the CCA and SCE must be tested and verified. Communications with SCE will be vital to ensuring successful CCA transactions related to electric meter reading and billing. SCE uses the Electronic Data Interchange (EDI) standard to facilitate the electronic communications and data exchange with CCAs. As part of the process of working with SCE to establish the CCA, SCE will conduct EDI testing to ensure that operational data exchange is functioning prior to the CCA commencing service.

Although not listed on the table, the CCA must also interact with the CAISO. The CAISO is an independent non-profit organization which coordinates, controls, and monitors the state's transmission, generation, and electric energy markets. The CAISO operates the CA wholesale power system which balances the need for higher transmission reliability with the need for lower costs. To become a CAISO market participant, a CCA must:

- Assign a certified Scheduling Coordinator (SC)[47] to manage bids in the CAISO ancillary service and energy markets. The SC must both be specially trained in CAISO procedures and must have access to a secure communications link to the CAISO system through either the Internet or through the Energy Communications Network (ECN).
- Develop and implement processes and systems to support resource interconnection

[46] Per CPUC Resolution 4907.
[47] CAISO Scheduling Coordinators: http://www.caiso.com/participate/Pages/SchedulingCoordinator/Default.aspx

- Utilize appropriate metering and telemetry where required[48]
- Participate in CAISO energy markets and related market products[49]

The CCA's contracted power provider and/or SC addresses these requirements.

[48] Metering and telemetry ensure operational accuracy: http://www.caiso.com/market/Pages/MeteringTelemetry/Default.aspx
[49] CAISO market processes and products: http://www.caiso.com/market/Pages/MarketProcesses.aspx

Table 19. Implementation Schedule, Hypothetical CCA Launch in 2022

Time	PER CPUC Requirements	COORDINATION WITH SCE	Internal CCA
Mid-year			City Commit to CCA formation via Ordinance
Sept-Nov	Draft Implementation Plan		Establish City Enterprise/JPA/governance model
Dec	File Implementation Plan with CPUC		Hire CEO, Procurement Manager, Finance Manager, Operations Manager
Jan-21	CPUC notifies SCE CPUC confirms it has the Implementation Plan	CSD begins meetings with SCE to confirm its operations will conform with SCE's tariffs	Issue RFPs for: • Initial power provider • Scheduling coordinator (if separate) • EDI/ data management • Communications • Banking/finance services • Working capital loan
Feb-21	CCA provides draft customer notices to CPUC public advisor Within 15 Days, CPUC PA finalizes notice and returns to CCA CCA submit registration packet to CPUC (signed serve agreement with SCE, Bond amount currently $147,000)		
Mar-21	CPUC informs CCA regarding any Exit Fees If the registration packet is complete, the CPUC confirms Registration as a CCA.		Evaluate Responses to RFPs
Apr-21	April 1: CCA submits year ahead RA forecast		Negotiate with selected firms
Jun-21			Have key contracts in place
Jul-21			Begin public roll out

Time	PER CPUC Requirements	COORDINATION WITH SCE	Internal CCA
Aug-21	CCA submits its updated year ahead RA forecast	CCA Service Agreement EDI Agreements Electronic Funds Transfer agreements	Set rate policies; NEM
Sep-21		Issue Binding Notice of Intent	
Sep-21	CCA demonstrates RA compliance		
Feb-22	October 15: CCAs submit their January load migration forecast for the Resource Adequacy program.	EDI Testing	
Mar-22	Send out 1st opt out notice		Lock in power prices
Apr-22	Send out 2nd opt out notice	Dec 1: Receive Customers Mass enrollment information from SCE	Set rates/ NEM compensation
May-21	Utility shall transfer all applicable accounts to the new supplier		
Jun-1	Begin Phase 1 service		

Set Up. The three main CCA set up requirements include participating in the Open Season, providing certain customer notifications, and undergoing electronic communications compliance testing as described below.

CCA Open Season[50] is a specific calendar period within which a CCA can voluntarily notify SCE of the planned implementation date of its program. This notification limits the CCA's exposure to additional stranded cost charges or exit fees. During Open Season, a CCA may submit a Binding Notice of Intent (BNI) informing SCE of the number of customers by class and date that the CCA will serve, including arrangements for phased service. SCE utilizes the BNI to modify power procurement forecasts to reflect loss of the CCA load, thus limiting the CRS. While Open Season participation is optional, it is an important tool for a CCA to limit customer cost exposure. Open Season occurs annually from January 1 through February 15 or as late as March 1 when the California Energy Commission (CEC) LSE Load Forecasts are due on or after May 1.

Customer Notifications, Opt-Out and Enrollment. CPUC Section 366.2(c)(3) contains several requirements regarding CCA customer notifications, enrollment, and opt-out rights.

A CCA must inform potential customers at least twice within two months (60 days) prior to the customers' designated date of CCA enrollment as follows:

- The customer is to be automatically enrolled in the CCA;
- The customer has the right to opt out of the CCA without penalty; and
- The terms and conditions of the services offered.

A similar notification must be made twice within two billing cycles subsequent to a customers' enrollment in the CCA. The CCA must pay SCE for providing these notices or can opt for direct mail notification.

Requirements per CPUC Resolution 4907

As noted above, the CPUC must review certain actions of newly forming CCAs. CPUC Resolution E-4907 establishes the schedule for its process of review to coordinate the timeline of the mandatory forecast filings of the Commission's Resource Adequacy program to ensure that newly launched and expanding CCAs comply with Resource Adequacy requirements, as established by Section 380, before they serve customers.

[50] SCE Rule 27.2 Community Choice Aggregation Open Season: http://regarchive.SCE.com/tm2/pdf/ELEC_ELEC-RULES_ERULE_27_2.pdf

Table 20. CCA Implementation Schedule Per CPUC Resolution 4907

Date	Action
Day 1, Year 1 (On or before January 1 Year 1)	(1) The prospective or expanding CCA submits its Implementation Plan to Energy Division and serves it on selected docket service lists
Day 1 – 10, Year 1	(1) The CPUC notifies the Utility servicing the customers that are proposed for aggregation that an implementation plan initiating their CCA program has been filed.
Day 1 – 60, Year 1	(1) The CCA provides a draft customer notice to CPUC's Public advisor. (2) Within 15 days of receipt of the draft notice, the Public Advisor shall finalize that notice and send it to the CCA.
DAY 1 – 90, Year 1	(1) The CPUC sends a letter confirming that it has received the Implementation Plan and certifying that the CCA has satisfied the requirements of Section 366.2(c) (3). (2) The CPUC provides the CCA with its findings regarding any cost recovery that must be paid by customers of the CCA in order to prevent cost shifting. (P.U. Code Section 366.2 (c) (7).) (3) The CCA and the Utility should Meet-and-Confer regarding the CCA's ability to conform its operations to the Utility's tariff requirements.
DAY 1 – 90, Year 1	(1) The CCA submits its registration packet to the CPUC, including: a. Signed service agreement with the utility, b. CCA interim bond of $100,000 or as determined in R.03-10-003
Day 90 – 120, Year 1	(1) If the registration packet is complete, the CPUC confirms Registration as a CCA.
April, Year 1	(1) The CCA submits its year ahead Resource Adequacy forecast (P.U. Code Section 380)
August, Year 1	(1) The CCA submits its updated year-ahead RA forecast
October Year 1 (75 days before service commences)	(1) CCAs submit their Monthly load migration forecast for the Resource Adequacy program, filed about 75 days prior to the compliance month.
Within 60 days of the CCA's Commencement of Customer Automatic Enrollment	(1) The CCA shall send its first opt-out notice.
Within 30 days of the CCA's Commencement of Customer Automatic Enrollment	(1) The CCA shall send a second opt-out notice. (2) Once notified of a CCA program, the Utility shall transfer all applicable accounts to the new supplier
January 1, Year 2	(1) CCA begins service.

Chapter 10: Conclusions

The general conclusions of this study are as follows:

1. The analysis performed here suggests that Community Choice Aggregation (CCA) could potentially be financially feasible for Long Beach.
2. Nonetheless, there are key assumptions, such as market power prices and the cost to comply with the state's Resource Adequacy requirements, that remain uncertain that could greatly impact the financial performance and operations a CCA. Some of these can be mitigated, such as wholesale power market price exposure through sound hedging practices. Others are more uncertain, such as regulatory changes.
3. Given Southern California Edison's (SCE's) rate design, the CCA cannot cost-effectively offer competitive rates to customers taking service at SCE Tariff TOU-8 subtransmission voltage (a subset of the largest industrial users). This means that a CCA would be better off deferring offering service to these customers until the CCA can do so without losing revenue or offering them rates that are higher than SCE's.
4. Simply forming a CCA does not guarantee greenhouse gas (GHG) savings. Achieving GHG reductions requires the CCA to do more than just meeting the state renewable requirements; it requires the CCA to either acquire power from large hydroelectric facilities (which are carbon-free but do not qualify as "renewable" under State law) at an unknown premium price or dramatically increase the renewable content of the power beyond that required by the State.
5. Because the city is fully developed, there is only modest opportunity for developing grid-connected solar PV. This conclusion applies only to larger PV arrays and not to rooftop, net metered solar.
6. Long Beach's two primary options for CCA are forming a City-only enterprise or joining with the Clean Power Alliance (CPA), the CCA currently serving large portions of Los Angeles and Ventura Counties. The primary benefits of forming a Long Beach-only CCA are more local control over procurement practices and budgets, and services better tailored to Long Beach. The primary benefits of joining CPA are the reduced risk and security of joining with an already-operating entity and reduced administrative burden on City Staff, both in CCA formation and in ongoing management.
7. A Long Beach CCA can possibly result in economic and employment benefits to the region by offering lower rates, directly employing residents, and causing local renewable energy and other projects to be built. However, the CCA should not be seem primarily as a tool for local economic development; there are likely other, less complex and risky ways to pursue ED goals.

Appendix 1: GIS-Based Assignment of Parcel Scores for Potential PV Solar Development

Summary

Many CCAs place a priority on developing renewable energy projects within their jurisdictions. Depending on the location, this has included wind, solar, and biomass. This study uses geographic information system (GIS) analysis of the City to identify potential locations for utility-scale solar photovoltaic installations (i.e., systems connected to the electric grid, as opposed to systems located on building rooftops designed primarily to serve the electric load of the building), rank the applicability of the potential sites, and estimate the total potential power production from the identified sites.

Using the GIS, each city parcel was "ranked" based on key criteria, such as site ownership, zoning, environmental sensitivity, current use of the parcel. Some criteria made a parcel more attractive—City ownership, for example—while other criteria made is less attractive or ruled it out—located in environmentally protected areas.

The study first confirmed the casual observation that there is little undeveloped land in the City. This eliminated what is generically a better class of large-scale solar: industrial brownfield parcels. Second, the study found that the best remaining sites tended to be parking lots and structures over which PV arrays could be placed. However, these are significantly more costly and more difficult to develop than brownfield sites.

Third, the Study identified the "best' 200 sites, and found them to offer the potential to generate approximately 100 MW of power.

Given the load of Long Beach—over 3000MW, and the difficulty and cost to develop the parking-based solar, the resource was not explicitly considered as a resource in the CCA analysis.

Analysis Framework

Goal: Develop a methodology and conduct a parcel-level analysis to identify parcels that could potentially support the development of PV solar arrays within the City of Long Beach, CA using a methodology of weighted overlays of factors that would positively or negatively influence the development of PV solar arrays on a subject parcel.

Data. Parcel data was obtained from the Los Angeles County Assessor's Office and clipped to only include parcels within the City of Long Beach Boundary. As the analysis unit for this project is a parcel, each parcel in the clipped dataset was further attributed based on its correspondence with additional overlapping datasets.

The additional overlay dataset sources were obtained from publicly available datasets representing factors that could positively or negatively influence the potential for a parcel to be used for development of a PV solar array. These datasets included; Flood zones, Wetlands, Protected Open Space, Environmental Hazard Sites, and City zoning, and others. A complete list of the data sources used in the analysis can be found in Appendix A.

Methodology. First, the parcel data was attributed with values representing the presence or absence of the parcel within intersecting positive or negative factor layers. A model was developed to iteratively identify whether each parcel intersected each overlapping layer by iteratively intersecting the parcel data with datasets representing different factors that would either positively or negatively influence PV solar development (factor layers).

For each factor layer in the iteration, a field was added to the parcel dataset representing that factor, and if all or part a parcel intersected (or touched) the factor layer, that field was assigned a value of 1. If no part of the parcel intersected the factor layer, that field was assigned a value of 0.

When the iteration model concluded, the parcel dataset was extended with many fields that contained a binary 0 or 1 value, representing a parcel's absence or presence from an area of potential positive or negative influence on PV solar development. A highly simplified example showing an example record is illustrated below.

APN	City Owned	(In) Wetland	(In) Historical Resource	(In) Coastal Zone	(In) Flood Zone	(In) Environmental Hazard Site	(In) Compatible Zoning
123-456-890	1	0	0	1	0	0	1

Parcel Factor Scoring

After ascertaining each parcel's presence or absence in a particular influencing factor area, each parcel was assigned a score using an equation that evaluated each parcel's presence or absence within each factor area. For each parcel, if the value of a particular factor field was 1 (i.e. the parcel was present in that factor area), the parcel would be considered to be influenced by that factor and a second positive or negative score was assigned for that factor on that parcel. The value of the score that was assigned was set to represent how strongly positive or negative that factor may be in influencing PV solar development, or how strongly that parcel is positively or negatively preferred for PV solar development based on that particular factor.

For example, City owned environmental hazard sites may be considered highly preferred locations for PV solar array development. In assigning factor scores, a high value (e.g. +5) could be assigned to a parcel present in an environmental hazard area to indicate a strong preference for such a parcel to be used for PV solar development. Similarly, City Owned parcels are also highly preferred, so a high value (e.g. +3) could be assigned to indicate these parcels are not as highly preferred as an environmental hazard site but are still very preferable when considering that factor.

Some factors may exert different strength weights depending on their level of influence (or preference), with a weight representing the potential influence that factor would have on PV solar development on that parcel, (or the potential preference for a parcel give that factor). For example, a parcel in a residential zone may be less desirable than a than a parcel in an industrial zone. Thus, a residential zoned parcel may be assigned a weight of -5 to indicate it is not preferred, while a parcel in a more preferred industrial zone is assigned a weight of +5 or higher.

Additionally, for parcels within factor areas that may wholly discourage the development of a PV array on that parcel, negative weight values that correspond with the level of negative potential for these parcels to support PV array development given that factor may be assigned. For example, it's unlikely that PV solar arrays would be developed on parcels within protected open space. Thus, parcels in those factor areas may be assigned a highly negative score of -5 or more, to indicate a strong negative preference.

In the first model iteration, all parcels were initially assigned a starting score of 5 and then assigned a +1 or -1 score for each factor evaluated. However, assigned factor scores can be modified to reflect the relative effect that factor has to positively or negatively influence PV solar development on each parcel. Thus, the assigned factor scores can be changed (and model calculations rerun) to correspond with different implementation alternatives the City may wish to evaluate.

Finally, for parcels not situated within an influencing factor area (a factor field value of 0), no weight relative value was assigned.

This evaluation of influencing factors and assignment of individual factor scores was performed for each parcel. Factor scores were then summed to derive a total Parcel-Factor Score that represented each parcel's potential for supporting PV solar development based on the influencing factors evaluated.

Parking Area Scoring

In addition to developing a score for individual parcels, the contribution that parking lots could make to increasing a parcel's preference for PV solar array development was incorporated into the model. GIS data defining parking lots was obtained from the Los Angeles County, GIS and clipped to the City boundary to exclude parking lots outside of the City limits. Each parcel was assigned a parking lot score that was calculated as the ratio of the total parking lot area/parcel area. This ratio represented the proportion of the parcel that is dedicated to parking. A value of 1.0 was added to the parking lot area/parcel area ratio so that the parking lot score could only improve the parcel-factor score and to compensate for the effect of a small parking lot score eliminating high combined scores of other factors.

Environmental Justice Factor Scoring

The analysis also factored in disadvantaged communities and environmental justice concerns by incorporating CalEnviroScreen (CES) data from the California Office of Environmental Health. The CES data helps identify California communities that are most affected by many sources of pollution, and where people are often especially vulnerable to pollution's effects. CalEnviroScreen uses environmental, health and socioeconomic information to produce scores for every census tract in the state. The scores are mapped so that different communities can be compared. An area with a high score is one that experiences a much higher pollution or socioeconomic burden than areas with low scores.[51]

The CalEnviroScreen score for each tract is composed of two main factors:

- A Pollution Score - that is a relative measure of exposure to pollution and environmental effects.
- A Population Characteristics Score – that is a relative measure of each tract's sensitive populations and socioeconomic factors.

Given the concern to consider environmental justice for this project, the analysis focused on the individual components that make up the Socioeconomic factors portion of CalEniroScreen's Population Characteristics score. Those are:

- Educational attainment
- Housing burdened low income households
- Linguistic isolation
- Poverty
- Unemployment

These individual socioeconomic factors scores range from 0-10, where higher numbers indicate a greater burden for that factor within a given Census tract.[52]

In this analysis, the percentile values for each socioeconomic factor that were present in the CalEnviroScreen data were used. To convert the percentile to a Parcel Factor score that could be incorporated into the parcel scoring methodology, the factor percentile value was subtracted from 100. The result was then divided by 100 and multiplied by 2 using the formula below:

Parcel Socioeconomic Factor Score = (100 – CES Socioeconomic Factor Score in %)/100 * 2

Parcels having low socioeconomic factor scores of 0-50 were considered to have a positive preference for potential PV development. Parcels having high socioeconomic factor scores of 50-100 were considered to have a negative preference due to high socioeconomic burdens.

This calculation was performed for each of the five socioeconomic factors evaluated and then averaged.

Total Parcel Score

Finally, a Parcel-Factor Score was computed by summing all individual factor scores. The parcel factor score, Parking lot score, and the Socioeconomic Score were combined to derive a total

[51] https://oehha.ca.gov/calenviroscreen
[52] Update to the California Communities Environmental Health Screening Tool, CalEnviroScreen 3.0, January 2017, page 12 https://oehha.ca.gov/media/downloads/calenviroscreen/report/ces3report.pdf

Parcel Score which represented the potential preference for each parcel for PV development, given all individual factor considerations. The Total Parcel Score was calculated as the Parcel-Factor Score * the Parking Lot Score * the Socioeconomic Score. All individual factor scores, the Parcel-Factor Score, the Parking Lot Score, and the Total Parcel Score were appended to the parcel attribute table so that parcels could be mapped and symbolized by their individual factor scores as well as their total scores, for subsequent evaluation and discussion with the project team.

Calculating Potential PV Energy Output

Lastly, estimates for potential PV energy output per parcel based on separate calculations rooftops and parking lots were added to the model parcel dataset.

Rooftops

Rooftop output estimates for each parcel were obtained from the Solar Map Database Excel file located on the LA County GIS Data Portal.[53] and appended the model parcel dataset, to represent rooftop potential energy output. This value represents a conservative estimate of total yearly output (kWh). Output is System Size multiplied by 1,490, as 1,490 is the number that utilities agreed was a conservative estimate of power output from a 1 kW system over a year, including power losses due to soiling, transmission from the panel to the inverter, and inverter efficiencies.[54]

Sys_size	System Size (kW). This takes the square feet of the Optimal Area and uses a SunPower 225 panel (18.1% efficient), which is 3'x5' (15 square feet). The calculation is Optimal Area divided by 15 (number of panels) multiplied by .225 (kW per panel).
Output	Total yearly output (kWh) Output is System Size multiplied by 1,490. 1,490 is the number that utilities agreed was a conservative estimate of power output from a 1 kW system over a year, including power losses due to soiling, transmission from the panel to the inverter, and inverter efficiencies.

Parking Lots

PV energy output for Parking lots was estimated using data for parking lots obtained from the LA County GIS Data Portal. The parking lots were first clipped with the City Boundary to exclude parking lots not in the City limits. Next, the same methods used to calculate the Total yearly output (kWh) Output for building rooftops used in the Los Angeles County analysis [4] were applied using an assumed a System Size (kW) based on a 3'x5' (15 square feet) SunPower 225 panel (18.1% efficient).

The "optimal area" for PV arrays in parking lots was computed using the method outlined by Black and Veach[55] in their Distributed PV Potential Assessment for Pasadena Water and Power which multiplied the gross square footage of each parking lot by 75 percent. This provided an estimate of the technical potential for PV installation based on Black & Veatch's experience with parking lot PV installations that accounts for the space needed to accommodate carport structures and retains some uncovered portions of the parking log driving.

[53] http://egis3.lacounty.gov/dataportal/wp-content/uploads/ShapefilePackages/Solar_Data_2010.zip - Solar Map Database (1.6 GB)
[54] https://egis3.lacounty.gov/dataportal/2015/04/07/solar-data-summarized-to-2010-parcels/ - Solar Map Data Descriptions.doc
[55] Renewable Energy - Distributed PV Potential Assessment for Pasadena Water and Power

The number or panels for each lot was estimated by dividing the “optimal area” by 15 (the size of each panel), with the result multiplied by .225 (the number or kW per panel). The resulting value is the estimated total yearly output for each parking lot in KWh.

The rooftop output value and the parking lot output estimates were then appended to the parcel dataset.

Appendix A

Influencing Factors and Data Sources Evaluated

Factor	Data Source	Influence on PV Development	Factor Score (weight)	Notes
Parcels	LA County Assessor 2018	*Analysis Unit	NA	Base Unit of analysis
City Boundary	City of Long Beach	NA	NA	Defines subset of parcels for analysis
City Ownership	LA County Assessor Parcel Ownership Info	Positive	+1	
Agriculture	City of Long Beach Zoning and California Department of Conservation Farmland Mapping and Monitoring Program (FMMP), LA County 2016	Negative	0	No Agricultural sites in the City
Environmental Hazard Concern Sites	GeoTracker and EnviroStor	Positive	+1	
Flood Zones	Federal Emergency Management Agency (FEMA)	Negative	-1	
Wetlands	National Wetland Inventory	Negative	-1	
Protected Habitat/Open Space	California Protected Areas Database	Negative	-1	
Critical Habitat	Fish and Wildlife Service Critical Habitat	Negative	0	No Critical Habitat within City Limits.
Farmland	California Department of Conservation Farmland Mapping and Monitoring Program (FMMP), LA County 2016	Negative	0	Only 'Z' (Out of Survey Area) attributed land within City Limits.
Williamson Act Land	California Department of Conservation, Division of Land Resource Protection, 2016.	Negative	0	No Williamson Act land within City Limits.
Historic Resources	City of Long beach	Negative	-1	

Factor	Data Source	Influence on PV Development	Factor Score (weight)	Notes
Coastal Zone		Negative	-1	Negative unless Parcel has an Industrial use?
Environmental Justice/Disadvantaged Community **Socioeconomic Factors**	California Office of Environmental Health Hazard Assessment CalEnviroScreen *Population Characteristics Score*	Negative	-1	High score reflects areas with high socioeconomic burdens
Zoning - Commercial	City of Long Beach	Positive	+1	
Zoning - Industrial	City of Long Beach	Positive	+1	
Zoning - Institutional	City of Long Beach	Positive	+1	
Zoning - Park	City of Long Beach		0	
Zoning - Planned Dev	City of Long Beach		0	
Zoning P ROW	City of Long Beach	Negative	-1	
Zoning - Residential	City of Long Beach	Negative	-1	
Zoning – Specific Plan	City of Long Beach		0	
Parking Lots	LA County GIS	Positive	+1	Parking Lot Area/Parcel Area ratio

Parcel Score represents combined positive and negative weights of individual influencing factors.

Parking lot Score represents a ratio of the total parking lot area/parcel area (or the proportion of the parcel area dedicated to parking + 1.

Appendix 2: CCA Energy Risk Management

The core business of CCAs, accounting for ~ 90% of the cost of serving a retail customer base, is energy commodity risk management.

Consider the fact that CCAs have to commit to providing customers with electricity at a certain price, under retail rates that are typically fixed over the course of the year. The price that customers pay the CCA for power doesn't vary too much, in relation to power market prices that are constantly fluctuating on an hourly, fifteen-minute and five-minute basis over the course of the year (and are quite volatile in California). That spread, between what customers pay and what market prices are, moment to moment, creates the single largest source of financial risk for the agency.

To think of this another way: if the CCA could just charge customers whatever the market price of power was at every moment, there wouldn't be any financial risk for the agency. Because all the risk would be on the customers — whose bills could double one month to the next. The CCA has to therefore act as an intermediary that protects customers from power market price fluctuations.

To do so, CCAs essentially buy insurance — by entering into forward contracts for physical power supplies at a fixed price, or financial products that have similar hedging benefits. This essentially transfers this risk from the CCA to a supplier or financial counterparty. Those counterparties will charge a premium to provide the CCA with power at a fixed price, in exchange for their taking on the market price risk. When market price spikes will occur cannot be known with certainty— and so suppliers charge an intrinsic risk premium that is spread out and increases the cost of all a CCA's forward contracts.

This is another source of risk for the CCA: balancing the cost of forward contracts with what the transaction is actually worth to the agency in terms of risk-adjusted returns. "Portfolio Strategy" is essentially an evaluation of how much to hedge in forward contracts, in different time periods over the year, and when to buy. Just like insurance, buying too much will just waste money for the CCA. For example, you wouldn't want to take out an insurance policy to specifically cover your car windshield. You might replace one or two windshields over all the cars you ever own — but you'd pay much more for that insurance product over the same time period.

To conduct this sort of trade-off valuation, CCAs have to forecast what their customers' pattern of electricity usage will be, hour over hour, month over month. To assess this "volumetric risk," CCAs will forecast a baseline analysis, and then assess how much electricity usage could increase or decrease depending on weather conditions and other risk factors. This also impacts how much customers will owe the CCA for their electricity usage.

A similar price forecasting exercise is conducted for power market "price risk," to assess the likelihood of market price spikes at certain times and how that could change depending on risk factors like the cost of natural gas, wind patterns, whether it will be a wet or dry hydroelectric season, and so on.

Subsequently, the CCA will match the load and price forecasts together and analyze the "swing risk": the likelihood that their customers electricity usage is positively or negatively correlated with market price spikes. This risk factor can be particularly severe, since the price risk and the volumetric risk are multiplied together. For example, say that a CCA assesses a high likelihood of market price spikes during certain days and hours in September, and there's also a high likelihood that when that happens, the CCAs customers are going to be using a lot of electricity. The CCA will want to make sure it hedges its financial exposure by buying forward contracts.

This exercise is what allows the CCA to analyze what it's expected range of financial exposure is at different times. Then the agency looks at what suppliers and financiers are charging for forward contracts — and when the product is priced at a fair value relative to what the insurance is worth to the CCA — the CCA will transact. Blocks of power covering certain hours are typically purchased and layered together to "fill up" the "open positions" underneath their retail load profile forecast to create a "portfolio" or "book" of power contracts.

Managing the portfolio is a continuous process, because all these risk factors are constantly changing, and the underlying mathematics, software, and data handling for all of this is complex. — thus, a source of "model error risk".

Lastly, there's "imbalance risk". That's during the trading day, whenever the CCAs actual electricity usage falls above or below its forecasted usage. That creates market price exposure for the CCA. If load is higher than expected, the CCA has to buy power directly from the market to cover its shortfall. If load is lower than expected, and the CCA has bought power in forward contracts, that power is sold onto the market (which can be at a loss or a profit).

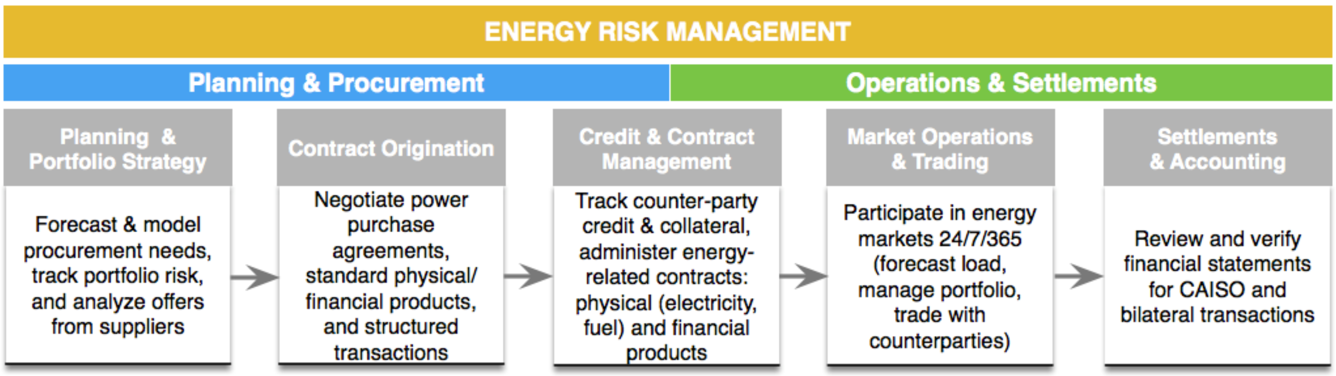
CCAs are allowed to schedule their load into the day-ahead or real-time markets in separately priced increments in part to hedge this risk. This "demand bidding strategy" requires predicting what the price levels and volatility risk will be in the day-ahead market versus the real-time market — referred to as the "DART spread" (i.e. Day Ahead vs. Real-Time market spread).

In summary, CCAs must manage:

- Risk in how retail customer rates are designed;
- Volumetric risk in terms of forecasting the pattern of electricity usage;
- Market price risk that forecasts the trends and likelihood of electricity market price spikes;
- Swing risk, which is the product of price and volumetric risk multiplied together;
- Model error risk, in terms of doing all these calculations correctly;
- The risk inherent in constructing a portfolio of forward power contracts, and accurately assessing when it makes financial sense to hedge or remain open to market exposure (and how much).

- Imbalance risk — unplanned market price exposure because of the difference between forecasted and actual electricity usage moment to moment.
- DART spread risk and demand bidding strategies — to intelligently and incrementally parse imbalance risk exposure across the Day Ahead and Real Time markets.

Consequently, risk management is a discipline that spans planning and portfolio analysis, contract origination and management, short-term load forecasting, scheduling and balancing of operations, and financial settlements — as shown in the figure below:



Source: Community Choice Partners

Commodity risk management within a competitive market is a complex practice. Supplying power to any aggregation of customers requires a diverse portfolio of energy products of various types and term lengths to be contracted for and actively managed as market conditions change over time.

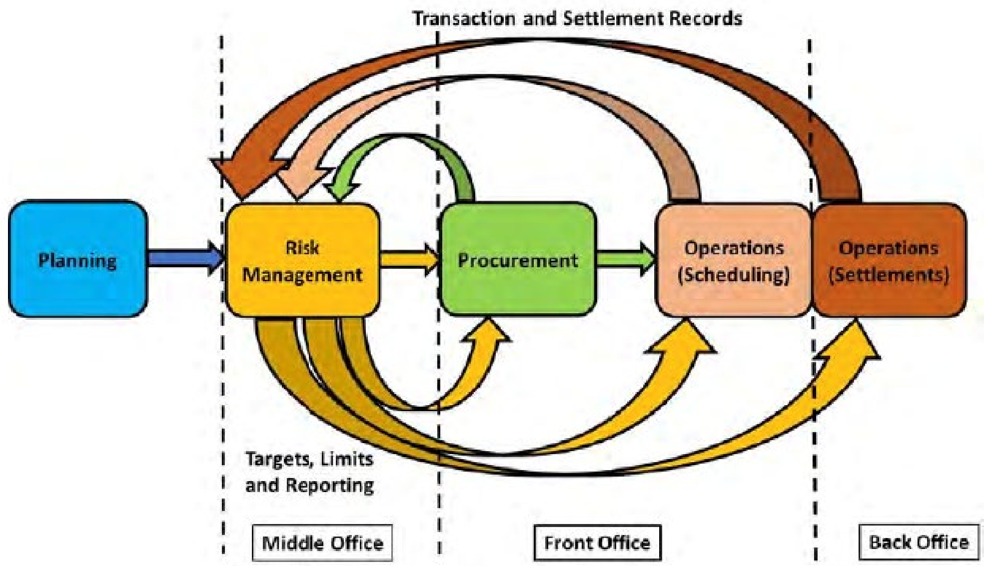
A "diversified portfolio" of energy products includes not just physical electricity products (energy, capacity, renewable certificates, emission reduction credits, ancillary services), but also physical fuel products (primarily natural gas, transportation and storage) as well as financial or insurance products (transmission congestion revenue rights, call/put options, etc.).

Significant expert analysis and market experience is required to assess how much of the portfolio should be contracted for in advance (hedged) versus exposed to market prices, and which products to purchase, in what volumes, when and from which counterparties in the market.

Subsequently, the portfolio has to be actively managed. Risk exposures may change in relationship to market price movements, the creditworthiness of counterparties, etc., and decisions taken whether to buy or sell certain products. During operations (the trading day on the market when contracts are settled), a number of contingencies can occur that also require intelligent decision making — including deviations between forecasted load and what customers actually use moment-to-moment, unplanned power plant outages, and market price volatility. Afterwards all of the data and financial obligations must be tracked, audited and settled in accordance with contracts and market rules.

Back, Middle and Front Office Functions

To organize these decisions and processes, the commodity risk management industry distinguishes between "back, middle and front office" departments and responsibilities:



Source: "Advanced Energy Risk Management Services for South Bay Clean Power: Questions and Answers with Five Portfolio Managers"

Within the commodity risk management discipline, the "**front office**" is the department that interfaces and transacts directly with buyers and sellers and the electricity market, while the "**back office**" collects all the data necessary to track and audit the financial settlements that occur after the trading day. The "**middle office**" conducts sophisticated forecasting and analytics to guide strategic decisions in the front office, continuously monitors sources of risk, and also provides independent (departmentally separate) management oversight of both front and back office transactions to ensure compliance with adopted risk management policies and transaction limits.

Underpinning the back, middle and front office operations is the governance of the enterprise. What is acceptable in terms of financial risk, and the specific ways that risk is managed in practice across the front, middle and back office (wherein the middle office is responsible for monitoring and compliance) is formally adopted in an Energy Risk Management Policy and accompanying Policies and operational Procedures; this trifecta is referred to as the "3Ps" of Energy Risk Management.

These documents are highly detailed, and specify the sources of financial risk, credit policies, the methodologies to be employed in assessing and reporting risk, the management oversight procedures that must be followed, the responsibilities of all staff and contractors involved, the transaction and trading authority delegated to specific parties therein (by product type, term length, volume and/or financial commitment), and what to do in the event that transaction limits or other rules are violated.

Front Office Procurement and Market Operations & Back Office Settlements

Power operations require an entity to be certified with the CAISO (the California Independent System Operator that oversees electricity market operations) as a "Scheduling Coordinator" to be able to submit short-term load forecasts, schedule power contracts, and receive data for settlements (invoice processing) while maintaining financial security requirements.

Transacting in the electricity markets require participants to post collateral, in amounts that vary according to the CAISO grid operator's estimate of each participant's financial exposure. The CAISO may revise these estimates as positions and market conditions change, and also make "margin calls" that draw upon this collateral and require additional capital to be posted as warranted.

Most energy products that a CCE transacts are physical electricity products contracted bilaterally in advance ("hedged"), and then scheduled in the electricity markets; the CCE then sells excess power or purchases any additional electricity required directly from the electricity markets. In this manner, the inevitable deviations between a CCE's expected load and the actual usage of customers moment to moment is a source of "imbalance" risk for the agency — with the magnitude of the financial risk determined by both the size of the CCE's market exposure and market price volatility (the price level of the market at the moment when electricity is purchased or sold). The ability of a CCE to maintain competitive rates over time as compared to the incumbent utility in part depends upon how expertly it manages its portfolio and sources of financial risk.

Consequently, it is not just the Scheduling Coordinator function but also the active trading capabilities of a front office that are strategically important for CCE; an energy portfolio that is diversified (in terms of various contract lengths, product types, and range of counterparties) affords more flexibility, lower cost and opportunity to manage risk — but doing so requires a comparatively sophisticated operation.

The front office department — not just the Scheduling Coordinator function (required to financially and operationally engage in the power markets in any capacity) but also the ability to actively manage diversified power portfolio by trading in the market and bilaterally with third-parties —requires substantial staff expertise and infrastructure, with trading desks and secure databases housed in "control centers" that are operated on a continuous basis (24/7).

Procuring energy products for a diversified portfolio requires various enabling agreements to be executed in advance with a range of counterparties that offer "physical" electricity and fuel products as well as financial and insurance products. These counterparties may be fuel suppliers, power plant operators, financial and insurance institutions, financial-only electricity market participants, wholesale suppliers and Energy Service Providers (ESPs) which maintain their own diversified portfolios.

Certain products are standardized and highly liquid (such as on- or off-peak block power purchases) while other "originated" products require customization and competitive negotiation with a range of suppliers. The front office procures these various energy products within transaction limits and guidance set by the middle office analytics; creditworthiness of counterparties must also be considered, as counterparty default or non-performance is a source of financial risk. All contracts executed (electricity, fuel, financial and insurance products) must be compiled in a database and managed in accordance with contract terms.

Depending on the contract, it may be bought, sold or exercised in advance of or during the trading day; the front office may buy or sell physical and financial products and exercise financial options as warranted by market conditions and risk management procedures.

The back office subsequently collects all the data necessary to track and audit the financial settlements that have accrued — both through the electricity markets directly (after the trading day for physical power products and certain financial products) and bilaterally outside of the electricity markets (which may be fuel, financial and insurance products).

Bilateral contracts outside of the electricity markets must be accounted for, settled or contested in accordance with contract terms. For daily transactions in the market directly, the CAISO grid operator informs market participants of their payment obligations and credits, which are re-calculated over time as more accurate data is received and analyzed (any changes in this regard are called “resettlements”, which take place over a matter of months). To verify the accuracy of the grid operator’s calculations, the back office has access to the underlying data and will often conduct “shadow settlement” calculations to duplicate the results; any discrepancies may be contested by market participants and clarified with the grid operator.

Planning and Middle Office: Forecasting, Modeling and Risk Management

The “middle office” forecasting analytics and oversight procedures that underpin Energy Risk Management are highly sophisticated, given that the forecasting must capture a wide degree of uncertainty across multiple, inter-related dimensions:

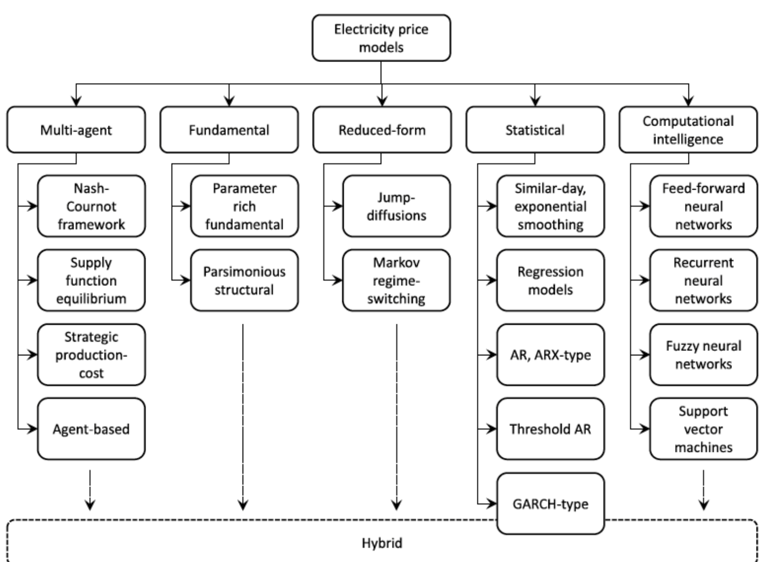
1. Volatility of electricity market, natural gas prices and seasonal hydroelectric generation output;
2. The inherent unpredictability of the underlying factors that impact price formation (such as weather that drives hourly patterns of electricity usage, varying by location across the power grid);
3. The constantly evolving nature of the power sector in terms of its:
    a. Physical characteristics and fleet composition (e.g. the dramatic acceleration of variable renewables and distributed energy, and acceleration of energy storage);
    b. Regulated market rules (e.g. the expansion of the CAISO Energy Imbalance Market to encompass other Western US balancing areas, etc.);
    c. The liquidity and range of products available to purchase (e.g. the new “super peak” block CAISO market power product, traditional on- and off-peak block power products, and the range of customized products available for negotiation).

Longer-term forecasting usually relies upon "fundamental" or "production cost" models: software platforms that actually simulate the power grid and market prices based on mathematical rules and complex planning datasets. These models capture changes to the power grid, composition of the wholesale fleet of power plants, patterns of load consumption, etc. and are able to predict a range of outcomes based on variable factors such as hydroelectric generation, seasonal weather patterns, natural gas price trends, distributed energy scenarios and new procurement mandates or changes in market rules that could impact how the entire system functions.

These "production cost" models are often relied upon for long-term Integrated Resource Planning and are able to simulate broad changes in the power sector. However, these models do not capture the strategic behavior of market participants (primarily, bidding strategies), and so are inaccurate for the purposes of commodity risk management over shorter timeframes.

Consequently, for the short- and medium- term forecasting used to inform portfolio strategies and risk management, the industry relies more heavily upon "technical" models: statistical techniques developed by the broader financial risk management industry and adapted for the energy sector. These models rely upon historical, observed data to implicitly capture the strategic behavior of other market participants.

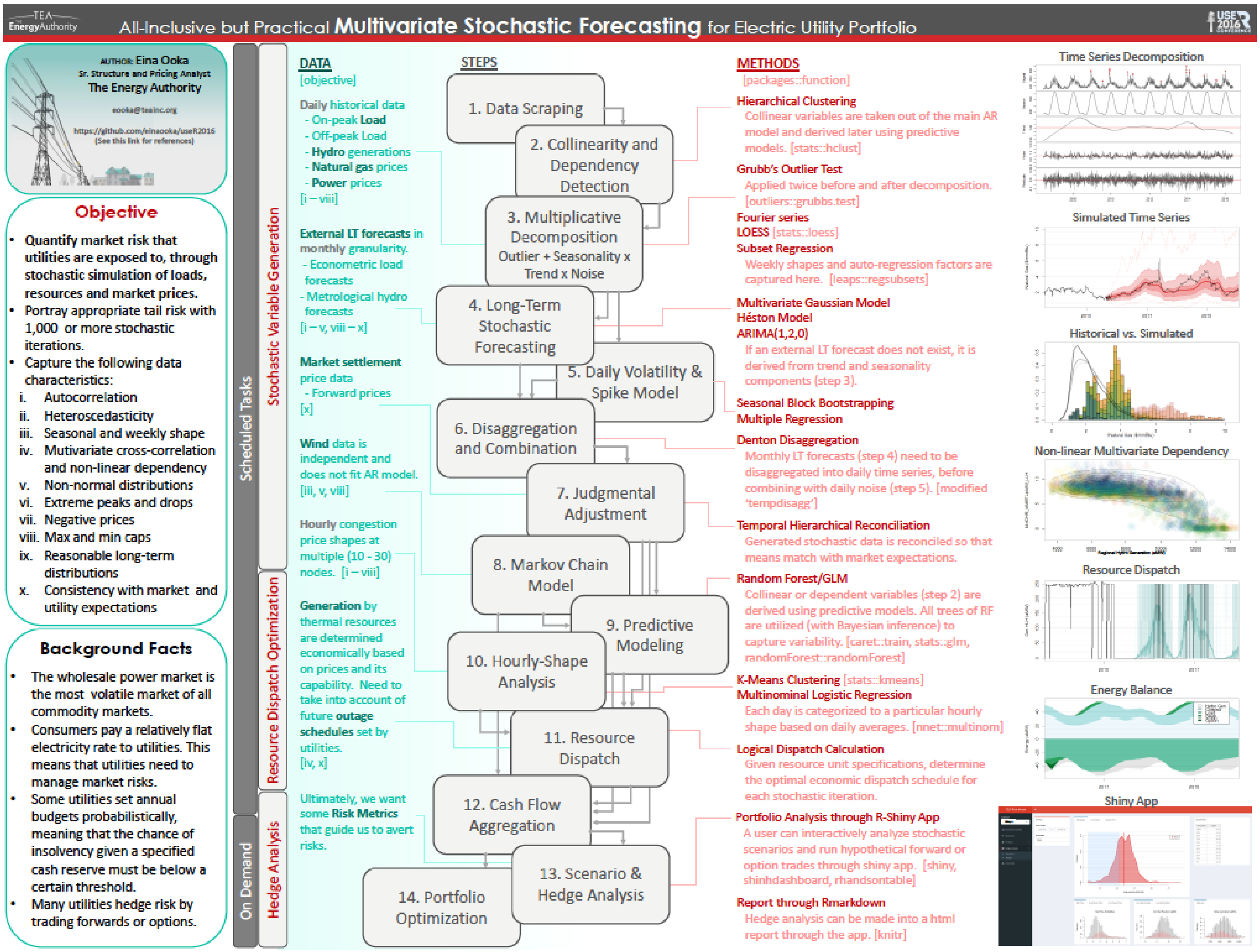
To do so, a range of techniques may be blended together, for example machine learning (artificial intelligence), econometric and stochastic algorithms, etc. All techniques have strengths and weaknesses that require expert judgment and constant attention to manage. There is therefore no "perfect forecast" methodology that is universally employed, as indicated by the below graphic, from an academic literature review of different modeling techniques employed in the power sector: [56]



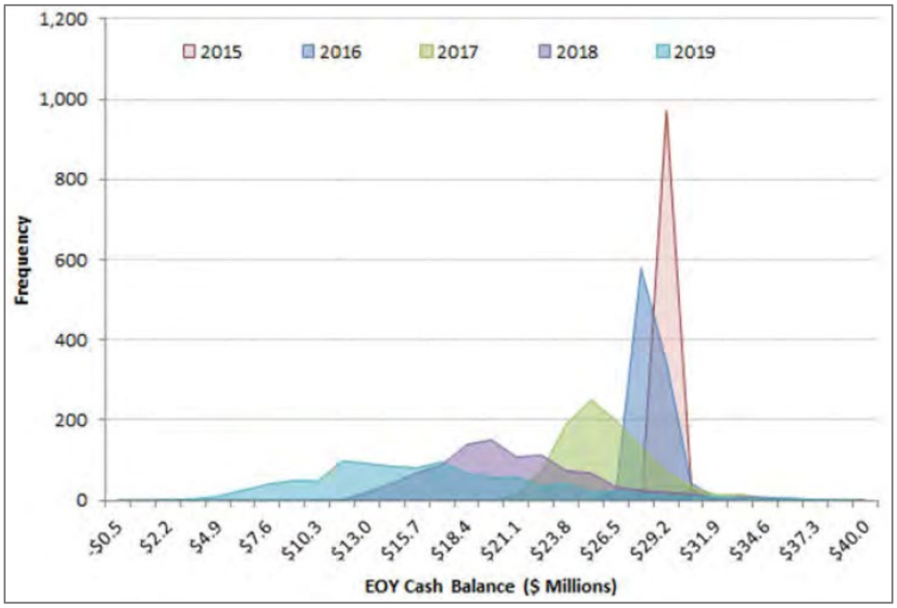
[56] Rafel Weron, "Electricity price forecasting: A review of the state-of-the-art with a look into the future", 2014, International Journal of Forecasting.

To illustrate this diversity and complexity, the graph below depicts the models created by a Portfolio Manager that is currently serving CCAs:

Source: The Energy Authority



Because of the inherent uncertainty being modeled, these simulations do not result in a single "deterministic" output or recommendation, but rather a more nuanced, "stochastic" range of probabilities that reflect potential outcomes and the financial impacts of any decision taken. The ability of the models to predict such a range of outcomes is generally tighter over the near-term, with broader ranges of outcomes over time:



Source: "Advanced Energy Risk Management Services for South Bay Clean Power: Questions and Answers with Five Portfolio Managers"

The accuracy of these complex analytics depends upon the quality and extent of the underlying data employed, as well as expert judgement regarding the data sources and various qualitative factors that could impact the calculations.

Effective Energy Risk Management consequently relies on a significant body of expertise, database infrastructure, and calculation methodology that is explicitly organized and strictly managed in accordance with adopted policies and oversight procedures.

Recommended best practices:

1. A tightly-integrated front, middle and back office — providing a high degree of assurance that a new CCE operates along established industry best-practices;
2. A comprehensive Energy Risk Management policy, along with the accompanying procedures and practices to ensure the Portfolio Manager is conforming to the CCE's risk policy;
3. The establishment of a Risk Management Committee, and full transparency in documenting all aspects of Energy Risk Management;
4. The practical ability to contract for and actively manage a diversified portfolio of not just electricity products, but also potentially fuel, financial and insurance products at launch;
5. Active risk management in market operations (balance of month transactions, and day-ahead and real-time trading);
6. In general, the broad assurance that a variety of proven, industry-standard modeling, software, expertise and management/oversight procedures are being employed to protect the CCE's interests.

Risk Management Program

Defining an Overarching Objective

The development of a risk management program starts with defining an overall objective that is the foundation for determining the effectiveness of a CCA's risk program and procurement activities. The objective has to be definitive, actionable and measurable. Objectives for a CCA should include the following:

- Cost to customers compared to incumbent utility
- Renewable energy procurement equal to state mandate, equal to or greater than incumbent utility
- Impact to emissions rates

Developing and Implementing a Risk Management Policy

The Risk Management Policy establishes the organization and defines department and personnel roles and responsibilities for ensuring that procurement is performed in a manner consistent with the CCA's overarching objective and within parameters authorized and delegated by the CCA's governing board. The Risk Management Policy addresses the following functions:

- Delegation of authority from the CCA's board authorizing individuals to transact, defining products that are suitable for transacting, establishing dollar, term and volume limits for each type of transaction
- Definition the roles, responsibilities and personnel that comprise the front office (procurement), middle office (monitoring and implementing controls for procurement) and back office (settlement, payment and receipt of revenue)
- Establishment of forward procurement targets to close the CCA's net open position during a time horizon spanning the next 3-5 years
- Definition of reporting mechanisms to effectively monitor risk and progress toward satisfying procurement targets
- Requirements for notifying board members or other authorized personnel in the event that a limit is breached, or unauthorized activity takes place
- Establishment of timelines for Risk Management Policy review and update as necessary
- Process to add and remove authorized personnel to the front, middle and back office roles
- Establishment of risk tolerance for counterparties
- Establishment of policy of diversifying risk by limiting exposure to counterparties, products and resource types

In addition, it is prudent for the CCA's board to establish a Risk Committee that meets with front, middle and back office personnel along with executive management to review recent operations, progress on closing net open positions for the time horizon and discussion of risk going forward.

Determining Net Open Position Volume and Hedging Targets

Energy. Energy net open position volume is determined by taking the long-term forecast for energy and subtracting supply volume over a rolling time horizon of three-to-five years. The result is net open position by month for the on-peak period (6 AM to 10 PM Monday through Saturday, excluding holidays), off-peak period (10 PM to 6AM Monday through Saturday and all day Sunday and holidays) and non-solar ramp hours (4PM to 8PM every day) for the next twelve-to-eighteen months and quarterly or annually for the rest of the time horizon. The energy net open position is compared to targets that are established by the Risk Management Policy.

Capacity (Resource Adequacy). Resource Adequacy is capacity that is acquired from power plant suppliers that can be counted toward meeting the LSE's hourly peak MW load each month. Each LSE demonstrates to the CPUC and CAISO that it has acquired enough Resource Adequacy capacity to satisfy its share of the system peak demand for each month. There are three types of Resource Adequacy capacity that is needed, system, local and flexible. System capacity can be supplied from anywhere on the grid and even from neighboring utilities. Local capacity can only be supplied from resources that reside within designated areas to ensure that enough generation in transmission-constrained areas is available to supply local load. Flexible capacity can also be supplied from anywhere on the grid but has to be controllable so that it can be called upon to increase energy output quickly enough to meet system needs when load increases while solar generation decreases.

Net open position is determined by comparing supply for each of the three capacity types against the requirements over a compliance period of three years[57].

Renewable Energy Credits. Renewable Energy Credits are MWh of energy produced by eligible renewable energy sources that are certified by the California Energy Commission. Each LSE has percentage targets for a compliance period that is mandated by the State. LSEs can choose to procure more than their mandate. Regardless, Renewable Energy Credits are measured against targets over the 3-5 year time horizon consistent with energy. The targets are categorized by compliance period.

Carbon Emissions. Although there is no mandate for carbon emissions, some CCAs have chosen to track carbon emissions against self-imposed targets. If a CCA has a self-imposed target, then the amount of carbon-free energy is compared to targets set by the Risk Management Policy.

[57] A fundamental change to Resource Adequacy procurement is moving forward. If approved, as expected by the end of 2019, Resource Adequacy will be procured by a central buyer and MWs and costs will be allocated to LSEs based on their requirements. LSEs can still procure their own Resource Adequacy and receive a lower or no allocated amount from the central buyer.

Valuing Net Open Position

The purpose of calculating the value of the Net Open Position is to monitor the cost of forward procurement to determine if volume hedging targets are sufficient. If forward prices increase or decrease substantially, a change to hedging targets may be warranted.

The Net Open Position volume is valued based on forward price curves multiplied by the MWh volume Net Open Position for the on-peak, off-peak and non-solar ramp hour periods. Forward price curves take into account natural gas cost, hydro-electric capability, new renewable energy resources and expected load. The calculation should be performed by the Middle Office no less than quarterly and if there is a material change to forward prices or Net Open Position.

Valuing Procured Energy and Products (Mark-to-Market)

The purpose of calculating the value of the energy, Resource Adequacy, Renewable Energy Credits and carbon-free products against current market prices is to ensure that exposure to counterparty default risk is commensurate with counterparty's credit ratings or collateral postings. If the mark-to-market value of the products provided by a counterparty exceed a threshold based on the counterparty's credit rating or collateral posting, the CCA may require additional collateral from the counterparty.

The mark-to-market value is based on forward price curves multiplied by the MWh volume of products that the CCA has procured.

Monitoring Reserve Margin

The purpose of monitoring Reserve Margin is to determine if the revenue from retail customers is consistent with expected revenue and greater than procurement costs and expected procurement costs. The actual Reserve Margin is compared with the target Reserve Margin to determine the revenue adequacy of retail rates. Reserve Margin should be monitored monthly but at least 6-8 months of data is needed to determine trends prior to making judgements as to the need to change rates or take other action.

Managing Risk

Net Revenue. Net revenue is monitored at a global portfolio level to determine overall revenue adequacy compared to procurement costs and then by tariff rate class to determine if each rate class supports itself. At a high level, rate classes are categorized as residential, small commercial, small industrial and large industrial. Each rate class has an expected revenue target based on usage and price to the consumer. By evaluating trends in Net Revenue over 6-8 months, the LSE can determine whether a rate class' price needs to be adjusted up or down to meet revenue margin targets.

In addition, an approach to managing Net Revenue risk is to allow individual customers to manage their individual portfolios allowing them to procure energy for their loads at costs that are specific to them. This can be done under the CCA's portfolio but with all costs and revenues passed through to the individual customer. This approach allows more sophisticated energy customers to manage their own portfolios and risks and reduces Net Revenue risk to the CCA.

Market Price. Market price risk is managed by laddering procurement over time similar to dollar cost averaging. The laddering of supply is based on the Net Open Position volume compared to hedge targets during the 3-5 year time horizon as defined in the Risk Management Policy. The targets become tighter as the delivery period approaches so that by the time the current quarter and month arrives, 95% to 100% of the Net Open Position is closed. Hedge targets for further out in the time horizon are lower to take into account uncertainty. A typical hedge target range for 3 years out is 50% to 75% and 5 years out is 25% to 50%.

This approach provides for timing diversification.

Volume. Supply volume risk can be managed by including performance guarantees so that if suppliers cannot deliver agreed upon volumes, then the CCA collects the performance guarantee to allow it to procure new supply at current market prices. The intent of the performance guarantee is to make up the difference between the contract price of energy that was not delivered and the new market price at which the LSE replaces the non-delivered energy and provide incentive for the supplier to deliver.

Load volume risk is managed by monitoring meter reads of actual customer usage compared against forecasts. Most large customers and some residential customers have set up on-line accounts with their incumbent utility to monitor their use and pay their energy invoices. In addition, there are various commercial applications which allow an LSE to access customer usage (with the customer's permission) to provide more timely feedback of key accounts to the forecasting process. The normal feedback loop relies upon receiving estimated usage from a meter data management agent 8 after delivery day that is submitted to the CAISO for settlement and 48 days later, final meter data.

Temporal. Temporal risk is managed by layering in supply in hourly volumes that match the LSE's expected hourly load consumption as close as possible. That entails acquiring fixed energy volume deliveries that vary hour-to-hour. The hourly fixed energy volumes are designed to fill in gaps between as-available energy from resources such as solar and wind that produce a portion of their output during load consumption periods but not all hours. Energy storage can be helpful as it allows for a shift of energy from one period when it may not be needed to another when it is needed to serve customer load.

Basis. Basis risk is managed by acquiring Congestion Revenue Rights (CRRs) from the CAISO. CRRs are financial instruments offered by the CAISO to pay market participants the difference between congestion prices at supply nodes and DLAPs.[58] CRRs are allocated to LSEs for the purpose of managing basis risk between supply and load. As a hedge, the LSE would determine the nodes at which its supply is provided and compares those nodal prices with the DLAP prices. The price differential that is caused by congestion can be mitigated by acquiring CRRs as the

[58] Note that if there is no congestion price difference between nodes, then there is no CRR settlement and CRR revenue or cost is $0.

CAISO will pay the CRR holder the difference in congestion prices between the supply nodes and DLAP[59].

Counterparty Credit. Counterparty credit exposure is limited by diversifying counterparties with which the CCA transacts. As described in previous sections, exposure with existing counterparties is monitored by the mark-to-market value of procured energy and other products relative to the counterparty's credit rating. Contracts are designed to include provisions for the LSE to call upon the counterparty to provide collateral to cover the mark-to-market value above a threshold that is commensurate with the counterparty's credit risk level.

Counterparty Performance. As described in the managing volumetric risk section, mitigating counterparty performance risk can be managed by including performance guarantees so that if suppliers cannot deliver agreed upon volumes, then the CCA collects the performance guarantee to allow it to procure new supply at current market prices. The intent of the performance guarantee is to make up the difference between the contract price of energy that was not delivered and the new market price at which the CCA replaces the non-delivered energy and provide incentive for the supplier to deliver.

Prior to executing a contract, the CCA can also reduce counterparty performance risk by including viability measures in the Request for Offers (RFO) process whereby potential generation projects are selected. Viability measures include factors such as interconnection status, environmental review, permitting, developer experience and technology. By including viability measures to the selection process along with price and location, the CCA can weed out projects that may not be viable.

Liquidity. The CCA can manage liquidity risk by establishing security and guarantee requirements to its power purchase agreements to ensure that the CCA is not caught short as a result of actions by counterparties.

Monitoring Net Revenue and comparing the results to budget expectations is critical to managing liquidity. In addition to steady state cash flows based on current and expected conditions, the CCA needs to run scenarios and sensitivities with material changes to market conditions and budget assumptions to understand the impacts to liquidity.

Regulatory. Monitoring the regulatory landscape to understand trends, new regulation and legislation that affect the electric utility sector is critical so that the CCA can take actions that are in line with regulatory and legislative changes. In addition to hiring personnel dedicated to following the regulatory trends, becoming a member of California Community Choice Association (CALCCA) is important as CALCCA follows these issues and advocates on behalf of CCAs.

[59] This can also be a cost to a CRR holder if congestion prices are lower at the DLAP than the supply nodes.

Financing Strategy Insights

The structural financial advantages that prospective CCAs like Long Beach possess (by virtue of being a coastal community, etc.) is only an advantage on paper, from a financier's perspective, unless the new agency is sufficiently operationally competent to realize it in practice.

A financial strategy for a CCA will analyze how the agency will fund its operations to meet its strategic objectives in this context — at launch and continuing into the future. It captures the initial startup phase of the agency and extends typically three to five years beyond that point as well. Generally, the strategy is primarily supported by quantitative analytics in the initial term, ceding to expert judgement further out on the timeline (as future conditions become less certain).

Strategic Context

This necessarily entails a more qualitative, strategic discussion than the 'hard numbers' in the above sections; as high-level context:

- Regardless of their geography, customer base and other attributes, CCAs possess a singular advantage over any other market incumbent: as new, competitive power agencies that are locally governed, they need not be constrained by legacy technologies, processes and thinking.
- This is a critical advantage in California's current market context, which is defined by state policymakers having set in motion a wave of top-down (e.g. renewables) and bottom-up (e.g. distributed energy) technology change without first considering whether the industry was structured and governed in a manner that could evolve, in terms of planning and operations, quickly enough to maintain the industry's core mission (affordability, reliability and safety) throughout the transition.
- Many experts, and increasingly the public, believe that it cannot, and that there is a generic need to align governance and decision-making with the pace of technology change and the market disruptions and physical instabilities that it is causing.
- Fundamentally, in a system where zero marginal cost, variable renewable energy generation is increasingly dominant (as required by RPS mandates, and driven on the retail side by electrification and self-generation):
    - The most valuable wholesale market product will become the flexible capacity necessary for system and local balancing; this holds true for distributed energy assets on the distribution grid.
    - The most valuable operational capability becomes the ability to respond quickly to geographically-specific, fluctuating prices (at the wholesale node, distribution circuit, etc.) and stability signals (frequency, voltage and thermal 'operating envelopes') across every dimension of the system, and to optimize the use of flexible capacity assets in response (i.e. to monetize the portfolio of assets to the greatest possible extent on behalf of your customer base).
    - The most valuable portfolio risk management (short-medium term) and planning (long-term) capability remains somewhat the same in principal (i.e. the ability to correctly forecast future retail customer usage patterns and system price dynamics),

but becomes both complicated and even more critical in practice due to all the fundamental technological changes — so the real challenge here is best thought of as "how to make uncertainty meaningful" in terms of decision-support analytics.

- In this context, California's Investor-Owned Utilities are heavily constrained in terms of what they can offer customers both by the CPUC's procedural requirements, institutional dynamics, outdated methodologies, lack of operational expertise and political agenda — and by the utilities' own legacy technologies, staff competencies, culture and business objectives. (Utilities conform to their economic incentive regimes and additionally, as a rule, tend to adopt the institutional characteristics of their regulators.)

That is why the rapid pace of technological change, institutional shortcomings on the part of the state regulator and utilities, and the consequent dynamism and volatility in the California market, are viewed by many operational experts not simply as risks but rather as upside opportunities for new CCAs — provided the agencies are properly structured to execute effectively.

Generating the most value for customers and communities through periods of market transition requires developing the ability to maintain strategic clarity while continuously evaluating the CCA's options across several dimensions:

  - How shifting fundamentals will necessitate specific changes to the current rule regime;
  - How technical dynamics will change as various interconnected rules are reformed;
  - Evaluation of the options under the current, transitional and future market states.

Financial Strategy Implications

The rapid evolution and market capture of the CCA industry in California has generated a range of practical insights in terms of agency model design and its implications for negotiating financing in the California market context. In general, lenders should view a CCA positively given the following sort of structural and qualitative characteristics:

1. Political support at the Board level, and a deference to qualified experts regarding balancing policy objectives with financial risks and requirements.

2. A CEO and senior staff with credible expertise (e.g. competitive retail, commodity risk management, data analytics and distributed energy), sufficient to exercise sound commercial judgement in overseeing innovative operations within a complex and dynamic marketplace, and with the leadership competencies required to create a culture of innovation for the new agency.

3. Active working relationships with other CCAs (e.g. joint-action activities) to coordinate on legislative and regulatory engagement, and to contract for and/or develop "shared services" in a manner that avoids needless duplication, shares competitive insights, saves costs and elevates the quality of key services and operational capabilities.

4. A comprehensive Energy Risk Management policy — with a reliance on financial position metrics appropriate to the California market, along with the procedures and practices to ensure that the CCA's staff and agents are conforming to the Board's adopted policy — and

the establishment of an engaged and expert Risk Management Committee that can credibly oversee and evolve risk management practices in-line with shifting technology, market and regulatory dynamics.

5. A tightly-integrated front, middle and back office, providing a high degree of assurance that a new CCA operates along established industry best-practices, affording the practical ability to contract for and actively manage a diversified portfolio (i.e. of not just electricity products, but also potentially fuel, financial and insurance products at launch), and able to exercise active risk management in market operations (balance of month transactions, and day-ahead and real-time trading).

6. A general focus on maximizing time-varying rates and the intelligent (e.g. co-optimized) use of distributed energy resources — as a sort of physical hedge, with substantial option value that includes local resiliency and distribution grid support services, against the market price volatility driven by variable renewables and the need to develop flexible ramping capacity on the supply and retail demand side of the business.

7. A near-term intent to establish a retail pricing desk and product structuring team to evolve these capacities from broad programmatic approaches to highly targeted, semi-automated and customized offers to individual customers in a manner that lowers sources of both fundamental and compliance-driven portfolio risk for the agency.

The most competitive CCAs are working together while internally leveraging the nimble nature of local governance, managerial competencies, and the ability of CCAs to quickly integrate the most cutting-edge private-sector capacities — in order to tackle operational challenges with a community-oriented, systems-thinking mentality that creates more value for customers than market incumbents are able to deliver.

For municipalities that follow suit in structuring CCAs as modern competitive power agencies, in order to negotiate favorable start-up financing (and provide for debt to be potentially repaid relatively quickly), an additional benefit is that doing so will additionally provide a strong foundation for the agency's competitive performance over the longer-term.

In short, the ability of a municipality to negotiate CCA financing on the most competitive terms, particularly in terms of lowering municipal guarantees, and then to subsequently accelerate debt repayment to mitigate this source of liability, is primarily a function of relying on operational expertise and adherence to good governance practices to "skate to where the puck is going."

Appendix 3: Detailed Pro Forma Outputs

MRW Financial Analysis of the Long Beach CCA
Scenario 1; Serving All Customers

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Expenses												
Cost of Power (including losses)		$0	$75,012,068	$138,509,549	$139,564,372	$139,639,122	$141,318,792	$142,218,233	$144,628,045	$147,859,770	$151,469,406	$156,027,060
Cost of Capacity (including losses)		$0	$9,155,543	$19,060,899	$24,923,030	$29,891,843	$31,926,501	$33,135,147	$32,087,694	$31,557,792	$31,368,096	$30,368,990
O&M/A&G Costs		$0	$6,957,248	$10,761,048	$11,489,059	$12,096,719	$9,965,018	$10,175,208	$10,393,711	$10,604,678	$10,815,038	$11,032,605
Total Expenses		**$0**	**$91,124,860**	**$168,331,496**	**$175,976,461**	**$181,627,684**	**$183,210,311**	**$185,528,589**	**$187,109,450**	**$190,022,240**	**$193,652,540**	**$197,428,655**
Debt Service		**$0**	**$2,434,013**	**$9,736,051**	**$9,736,051**	**$9,736,051**	**$9,736,051**	**$7,302,038**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement		**$0**	**$93,558,872**	**$178,067,546**	**$185,712,511**	**$191,363,735**	**$192,946,362**	**$192,830,626**	**$187,109,450**	**$190,022,240**	**$193,652,540**	**$197,428,655**
Total Sales, MWh		-	1,599,627	3,157,142	3,164,989	3,154,224	3,142,094	3,125,271	3,110,369	3,095,783	3,081,155	3,067,115
SCE CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)												
Average CCA generation		$0.0	$58.5	$56.4	$58.7	$60.7	$61.4	$61.7	$60.2	$61.4	$62.9	$64.4
IOU average exit fees for CCA load		$0.0	$12.7	$12.1	$12.4	$12.3	$12.1	$12.0	$12.1	$10.1	$6.8	$1.2
Max CCA Rate		**$0.0**	**$71.2**	**$68.5**	**$71.0**	**$73.0**	**$73.5**	**$73.7**	**$72.3**	**$71.5**	**$69.6**	**$65.6**
IOU average gen rate for CCA load w/o discount, $/MWh		$0.0	$75.7	$77.2	$80.4	$81.9	$83.5	$85.5	$87.5	$87.0	$87.7	$87.4
IOU average gen rate for CCA load + discount + FF		**$0.0**	**$75.00**	**$76.54**	**$79.69**	**$81.11**	**$82.78**	**$84.72**	**$86.67**	**$86.22**	**$86.87**	**$86.56**
Revenues	**RATE SAVINGS**		**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Ave CCA Rate, $/MWh		*$0.0*	*$62.3*	*$64.5*	*$67.3*	*$68.8*	*$70.7*	*$72.7*	*$74.5*	*$76.1*	*$80.1*	*$85.4*
Rate Revenue			$104,045,640	$202,598,668	$212,136,834	$216,121,057	$221,173,997	$227,141,827	$231,860,151	$235,687,710	$246,723,383	$261,799,814
Net Uncollectibles			($260,114)	($506,497)	($530,342)	($540,303)	($552,935)	($567,855)	($579,650)	($589,219)	($616,808)	($654,500)
Other Revenue (Loans)		$27,469,143										
Interest	1.25%	*$0*	*$343,364*	*$475,490*	*$631,654*	*$964,594*	*$1,279,365*	*$1,641,290*	*$2,083,598*	*$2,661,781*	*$3,258,507*	*$3,954,914*
Total Revenue		$27,469,143	$104,128,890	$202,567,660	$212,238,146	$216,545,349	$221,900,426	$228,215,263	$233,364,099	$237,760,272	$249,365,081	$265,100,228
Expenses												
Cost of Power		$0	($75,012,068)	($138,509,549)	($139,564,372)	($139,639,122)	($141,318,792)	($142,218,233)	($144,628,045)	($147,859,770)	($151,469,406)	($156,027,060)
Cost of Capacity (including losses)		$0	($9,155,543)	($19,060,899)	($24,923,030)	($29,891,843)	($31,926,501)	($33,135,147)	($32,087,694)	($31,557,792)	($31,368,096)	($30,368,990)
O&M/A&G Costs		$0	($6,957,248)	($10,761,048)	($11,489,059)	($12,096,719)	($9,965,018)	($10,175,208)	($10,393,711)	($10,604,678)	($10,815,038)	($11,032,605)
Other Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses		$0	($91,124,860)	($168,331,496)	($175,976,461)	($181,627,684)	($183,210,311)	($185,528,589)	($187,109,450)	($190,022,240)	($193,652,540)	($197,428,655)
Unleveraged Free Cash Flow		$27,469,143	$13,004,030	$34,236,165	$36,261,686	$34,917,665	$38,690,115	$42,686,674	$46,254,649	$47,738,033	$55,712,541	$67,671,573
Debt Service			($2,434,013)	($9,736,051)	($9,736,051)	($9,736,051)	($9,736,051)	($7,302,038)	$0	$0	$0	$0
Leveraged Free Cash Flow		$27,469,143	$10,570,018	$24,500,114	$26,525,635	$25,181,614	$28,954,064	$35,384,636	$46,254,649	$47,738,033	$55,712,541	$67,671,573
Working cash on hand		$27,469,143	$38,039,161	$50,532,337	$77,167,550	$102,349,164	$131,303,229	$166,687,865	$212,942,513	$260,680,546	$316,393,088	$384,064,661
Minimum Cash on hand			*$26,032,223*	*$50,641,915*	*$53,059,537*	*$54,136,337*	*$55,475,107*	*$57,053,816*	*$58,341,025*	*$59,440,068*	*$62,341,270*	*$66,275,057*
Cash (to)/From reserve			($12,006,939)	$109,578	($15,959,517)	($847,683)	($237,394)	$0	$0	$0	($105,927)	($566,417)
End of Year Cash		**$27,469,143**	**$26,032,223**	**$50,641,915**	**$61,208,034**	**$101,501,481**	**$131,065,835**	**$166,687,865**	**$212,942,513**	**$260,680,546**	**$316,287,161**	**$383,498,243**
Reserve Fund Adjustment		**15%**										
Target		$0	$14,033,831	$26,710,132	$27,856,877	$28,704,560	$28,941,954	$28,924,594	$28,066,418	$28,503,336	$29,047,881	$29,614,298
Reserve Fund Adjustment												
Potential Reserve Addition		*$0*	*$14,033,831*	*$14,703,193*	*$15,959,517*	*$847,683*	*$237,394*	*-$17,360*	*-$875,537*	*-$438,618*	*$105,927*	*$566,417*
Reserve additions (Subtractions)		$0	$12,006,939	-$109,578	$15,959,517	$847,683	$237,394	$0	$0	$0	$105,927	$566,417
Reserve fund total		**$0**	**$12,006,939**	**$11,897,360**	**$27,856,877**	**$28,704,560**	**$28,941,954**	**$28,941,954**	**$28,941,954**	**$28,941,954**	**$29,047,881**	**$29,614,298**

MRW Financial Analysis of the Long Beach CCA
Scenario 1; Not Serving TOU-8 subtrans.

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Expenses												
Cost of Power (including losses)		$0	$52,843,948	$102,908,813	$103,630,803	$103,568,475	$99,030,564	$105,657,149	$107,365,403	$109,616,283	$112,321,847	$115,673,748
Cost of Capacity (including losses)		$0	$4,256,024	$10,551,794	$11,597,124	$12,160,755	$13,712,446	$27,399,136	$26,677,621	$26,338,784	$26,251,497	$25,565,736
O&M/A&G Costs		$0	$6,957,248	$10,761,048	$11,489,059	$12,096,719	$9,965,018	$10,175,208	$10,393,711	$10,604,678	$10,815,038	$11,032,605
Total Expenses		**$0**	**$64,057,220**	**$124,221,655**	**$126,716,987**	**$127,825,949**	**$122,708,028**	**$143,231,493**	**$144,436,736**	**$146,559,745**	**$149,388,382**	**$152,272,089**
Debt Service		**$0**	**$1,874,637**	**$7,498,548**	**$7,498,548**	**$7,498,548**	**$7,498,548**	**$5,623,911**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement		**$0**	**$65,931,857**	**$131,720,203**	**$134,215,535**	**$135,324,497**	**$130,206,576**	**$148,855,404**	**$144,436,736**	**$146,559,745**	**$149,388,382**	**$152,272,089**
Total Sales, MWh		-	1,110,668	2,303,297	2,309,022	2,301,168	2,292,319	2,280,046	2,269,174	2,258,532	2,247,860	2,237,618
SCE CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)												
Average CCA generation		$0.0	$59.4	$57.2	$58.1	$58.8	$56.8	$65.3	$63.7	$64.9	$66.5	$68.1
IOU average exit fees for CCA load		$0.0	$13.4	$12.8	$13.1	$13.0	$12.8	$12.7	$12.8	$10.7	$7.2	$1.3
Max CCA Rate		**$0.0**	**$72.8**	**$70.0**	**$71.2**	**$71.8**	**$69.6**	**$78.0**	**$76.5**	**$75.5**	**$73.6**	**$69.3**
IOU average gen rate for CCA load w/o discount, $/MWh		$0.0	$80.2	$81.5	$84.6	$86.1	$87.9	$89.8	$91.8	$91.2	$95.0	$94.7
IOU average gen rate for CCA load + discount + FF		**$0.0**	**$79.47**	**$80.76**	**$83.82**	**$85.30**	**$87.06**	**$89.02**	**$91.00**	**$90.37**	**$94.12**	**$93.79**
Revenues	**RATE SAVINGS**		**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Ave CCA Rate, $/MWh		*$0.0*	*$66.1*	*$68.0*	*$70.8*	*$72.3*	*$74.3*	*$76.3*	*$78.2*	*$79.7*	*$86.9*	*$92.5*
Rate Revenue			$79,265,290	$155,994,623	$162,734,741	$165,764,559	$169,633,985	$173,983,804	$177,447,375	$180,033,890	$195,448,989	$207,025,226
Net Uncollectibles			($198,163)	($389,987)	($406,837)	($414,411)	($424,085)	($434,960)	($443,618)	($450,085)	($488,622)	($517,563)
Other Revenue (Loans)		$20,794,931										
Interest	**0.00%**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue		$20,794,931	$79,067,127	$155,604,636	$162,327,904	$165,350,148	$169,209,900	$173,548,844	$177,003,756	$179,583,805	$194,960,367	$206,507,663
Expenses												
Cost of Power		$0	($52,843,948)	($102,908,813)	($103,630,803)	($103,568,475)	($99,030,564)	($105,657,149)	($107,365,403)	($109,616,283)	($112,321,847)	($115,673,748)
Cost of Capacity (including losses)		$0	($4,256,024)	($10,551,794)	($11,597,124)	($12,160,755)	($13,712,446)	($27,399,136)	($26,677,621)	($26,338,784)	($26,251,497)	($25,565,736)
O&M/A&G Costs		$0	($6,957,248)	($10,761,048)	($11,489,059)	($12,096,719)	($9,965,018)	($10,175,208)	($10,393,711)	($10,604,678)	($10,815,038)	($11,032,605)
Other Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses		$0	($64,057,220)	($124,221,655)	($126,716,987)	($127,825,949)	($122,708,028)	($143,231,493)	($144,436,736)	($146,559,745)	($149,388,382)	($152,272,089)
Unleveraged Free Cash Flow		$20,794,931	$15,009,906	$31,382,981	$35,610,917	$37,524,199	$46,501,873	$30,317,351	$32,567,021	$33,024,060	$45,571,985	$54,235,573
Debt Service			($1,874,637)	($7,498,548)	($7,498,548)	($7,498,548)	($7,498,548)	($5,623,911)	$0	$0	$0	$0
Leveraged Free Cash Flow		$20,794,931	$13,135,269	$23,884,434	$28,112,370	$30,025,651	$39,003,325	$24,693,440	$32,567,021	$33,024,060	$45,571,985	$54,235,573
Working cash on hand		$20,794,931	$33,930,200	$47,924,855	$67,013,529	$97,039,179	$136,042,504	$160,735,944	$193,302,965	$226,327,025	$271,899,010	$326,134,583
Minimum Cash on hand			*$19,766,782*	*$38,901,159*	*$40,581,976*	*$41,337,537*	*$42,302,475*	*$43,387,211*	*$44,250,939*	*$44,895,951*	*$48,740,092*	*$51,626,916*
Cash (to)/From reserve			($9,889,779)	($9,023,696)	($1,218,855)	($166,344)	$0	($2,029,636)	$0	$0	($79,947)	($432,556)
End of Year Cash		**$20,794,931**	**$24,040,422**	**$38,901,159**	**$65,794,673**	**$96,872,835**	**$136,042,504**	**$158,706,308**	**$193,302,965**	**$226,327,025**	**$271,819,063**	**$325,702,027**
Reserve Fund Adjustment		**15%**										
Target		$0	$9,889,779	$19,758,030	$20,132,330	$20,298,675	$19,530,986	$22,328,311	$21,665,510	$21,983,962	$22,408,257	$22,840,813
Reserve Fund Adjustment												
Potential Reserve Addition		*$0*	*$9,889,779*	*$9,868,252*	*$1,218,855*	*$166,344*	*-$767,688*	*$2,029,636*	*-$662,800*	*-$344,349*	*$79,947*	*$432,556*
Reserve additions (Subtractions)		$0	$9,889,779	$9,023,696	$1,218,855	$166,344	$0	$2,029,636	$0	$0	$79,947	$432,556
Reserve fund total		**$0**	**$9,889,779**	**$18,913,475**	**$20,132,330**	**$20,298,675**	**$20,298,675**	**$22,328,311**	**$22,328,311**	**$22,328,311**	**$22,408,257**	**$22,840,813**

MRW Financial Analysis of the Long Beach CCA
Scenario 2; Serving All Customers
(Accelerated renewables)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Expenses											
Cost of Power (including losses)		$0	$77,734,960	$148,050,819	$149,800,477	$150,736,025	$150,466,525	$155,170,855	$159,824,240	$166,168,685	$172,645,873
Cost of Capacity (including losses)		$0	$8,177,728	$16,702,205	$18,199,341	$18,798,177	$20,756,046	$28,693,499	$26,418,541	$24,838,379	$23,880,242
O&M/A&G Costs		$0	$6,957,248	$10,761,048	$11,489,059	$12,096,719	$9,965,018	$10,175,208	$10,393,711	$10,604,678	$10,815,038
Total Expenses		**$0**	**$92,869,936**	**$175,514,072**	**$179,488,877**	**$181,630,920**	**$181,187,589**	**$194,039,563**	**$196,636,493**	**$201,611,742**	**$207,341,154**
Debt Service		**$0**	**$2,541,671**	**$10,166,683**	**$10,166,683**	**$10,166,683**	**$10,166,683**	**$7,625,012**	**$0**	**$0**	**$0**
Total Revenue Requirement		**$0**	**$95,411,607**	**$185,680,755**	**$189,655,560**	**$191,797,603**	**$191,354,272**	**$201,664,575**	**$196,636,493**	**$201,611,742**	**$207,341,154**
Total Sales, MWh		-	1,599,627	3,157,142	3,164,989	3,154,224	3,142,094	3,125,271	3,110,369	3,095,783	3,081,155
SCE CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)											
Average CCA generation		$0.0	$59.6	$58.8	$59.9	$60.8	$60.9	$64.5	$63.2	$65.1	$67.3
IOU average exit fees for CCA load		$0.0	$12.7	$12.1	$12.4	$12.3	$12.1	$12.0	$12.1	$10.1	$6.8
Max CCA Rate		**$0.0**	**$72.3**	**$70.9**	**$72.3**	**$73.1**	**$73.0**	**$76.6**	**$75.3**	**$75.2**	**$74.1**
IOU average gen rate for CCA load w/o discount, $/MWh		$0.0	$74.0	$75.2	$78.1	$79.4	$81.1	$82.9	$84.8	$84.2	$87.7
IOU average gen rate for CCA load + discount + FF		**$0.0**	**$73.34**	**$74.54**	**$77.35**	**$78.72**	**$80.35**	**$82.16**	**$83.99**	**$83.40**	**$86.87**
Revenues	**RATE SAVINGS**		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ave CCA Rate, $/MWh		*$0.0*	*$60.7*	*$62.5*	*$65.0*	*$66.4*	*$68.3*	*$70.1*	*$71.9*	*$73.3*	*$80.1*
Rate Revenue			$101,321,063	$196,285,604	$204,783,904	$208,624,700	$213,537,526	$219,151,987	$223,531,326	$226,966,045	$246,723,383
Net Uncollectibles			($253,303)	($490,714)	($511,960)	($521,562)	($533,844)	($547,880)	($558,828)	($567,415)	($616,808)
Other Revenue (Loans)		$27,899,436									
Interest	1.25%	$0	$348,743	$423,804	$448,651	$801,496	$1,015,334	$1,298,644	$1,526,621	$1,874,904	$2,208,176
Total Revenue		$27,899,436	$101,416,503	$196,218,695	$204,720,595	$208,904,634	$214,019,017	$219,902,750	$224,499,118	$228,273,534	$248,314,750
Expenses											
Cost of Power		$0	($77,734,960)	($148,050,819)	($149,800,477)	($150,736,025)	($150,466,525)	($155,170,855)	($159,824,240)	($166,168,685)	($172,645,873)
Cost of Capacity (including losses)		$0	($8,177,728)	($16,702,205)	($18,199,341)	($18,798,177)	($20,756,046)	($28,693,499)	($26,418,541)	($24,838,379)	($23,880,242)
O&M/A&G Costs		$0	($6,957,248)	($10,761,048)	($11,489,059)	($12,096,719)	($9,965,018)	($10,175,208)	($10,393,711)	($10,604,678)	($10,815,038)
Other Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses		$0	($92,869,936)	($175,514,072)	($179,488,877)	($181,630,920)	($181,187,589)	($194,039,563)	($196,636,493)	($201,611,742)	($207,341,154)
Unleveraged Free Cash Flow		$27,899,436	$8,546,567	$20,704,622	$25,231,718	$27,273,714	$32,831,428	$25,863,188	$27,862,625	$26,661,791	$40,973,597
Debt Service			($2,541,671)	($10,166,683)	($10,166,683)	($10,166,683)	($10,166,683)	($7,625,012)	$0	$0	$0
Leveraged Free Cash Flow		$27,899,436	$6,004,896	$10,537,940	$15,065,035	$17,107,032	$22,664,745	$18,238,176	$27,862,625	$26,661,791	$40,973,597
Working cash on hand		$27,899,436	$33,904,333	$35,892,066	$64,119,709	$81,226,740	$103,891,486	$122,129,661	$149,992,287	$176,654,078	$217,627,675
Minimum Cash on hand			*$25,354,126*	*$49,054,674*	*$51,180,149*	*$52,226,159*	*$53,504,754*	*$54,975,688*	*$56,124,780*	*$57,068,383*	*$62,078,688*
Cash (to)/From reserve			($8,550,207)	$13,162,608	($12,939,560)	($20,442,482)	$0	($1,480,046)	$0	$0	($851,487)
End of Year Cash		**$27,899,436**	**$25,354,126**	**$49,054,674**	**$51,180,149**	**$60,784,259**	**$103,891,486**	**$120,649,615**	**$149,992,287**	**$176,654,078**	**$216,776,188**
Reserve Fund Adjustment		**15%**									
Target		$0	$14,311,741	$27,852,113	$28,448,334	$28,769,640	$28,703,141	$30,249,686	$29,495,474	$30,241,761	$31,101,173
Reserve Fund Adjustment											
Potential Reserve Addition		*$0*	*$14,311,741*	*$19,301,906*	*$33,060,735*	*$20,442,482*	*-$66,500*	*$1,480,046*	*-$754,212*	*-$7,925*	*$851,487*
Reserve additions (Subtractions)		$0	$8,550,207	-$13,162,608	$12,939,560	$20,442,482	$0	$1,480,046	$0	$0	$851,487
Reserve fund total		**$0**	**$8,550,207**	**-$4,612,401**	**$8,327,159**	**$28,769,640**	**$28,769,640**	**$30,249,686**	**$30,249,686**	**$30,249,686**	**$31,101,173**

MRW Financial Analysis of the Long Beach CCA
Scenario 2; Not Serving TOU-8 subtrans.
(Accelerated renewables)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Expenses											
Cost of Power (including losses)		$0	$54,770,145	$110,019,602	$111,302,740	$112,073,902	$105,029,841	$115,224,647	$118,590,125	$123,140,226	$127,963,917
Cost of Capacity (including losses)		$0	$3,947,984	$9,901,884	$10,710,959	$10,882,264	$12,337,498	$24,118,297	$22,490,082	$21,375,467	$20,720,568
O&M/A&G Costs		$0	$6,957,248	$10,761,048	$11,489,059	$12,096,719	$9,965,018	$10,175,208	$10,393,711	$10,604,678	$10,815,038
Total Expenses		**$0**	**$65,675,377**	**$130,682,535**	**$133,502,757**	**$135,052,885**	**$127,332,357**	**$149,518,153**	**$151,473,918**	**$155,120,370**	**$159,499,523**
Debt Service		**$0**	**$1,959,941**	**$7,839,765**	**$7,839,765**	**$7,839,765**	**$7,839,765**	**$5,879,824**	**$0**	**$0**	**$0**
Total Revenue Requirement		**$0**	**$67,635,318**	**$138,522,300**	**$141,342,522**	**$142,892,650**	**$135,172,122**	**$155,397,977**	**$151,473,918**	**$155,120,370**	**$159,499,523**
Total Sales, MWh		-	1,110,668	2,303,297	2,309,022	2,301,168	2,292,319	2,280,046	2,269,174	2,258,532	2,247,860
SCE CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)											
Average CCA generation		$0.0	$60.9	$60.1	$61.2	$62.1	$59.0	$68.2	$66.8	$68.7	$71.0
IOU average exit fees for CCA load		$0.0	$13.4	$12.8	$13.1	$13.0	$12.8	$12.7	$12.8	$10.7	$7.2
Max CCA Rate		**$0.0**	**$74.3**	**$72.9**	**$74.3**	**$75.1**	**$71.7**	**$80.9**	**$79.6**	**$79.3**	**$78.1**
IOU average gen rate for CCA load w/o discount, $/MWh		$0.0	$80.2	$81.5	$84.6	$86.1	$87.9	$89.8	$91.8	$91.2	$95.0
IOU average gen rate for CCA load + discount + FF		**$0.0**	**$79.47**	**$80.76**	**$83.82**	**$85.30**	**$87.06**	**$89.02**	**$91.01**	**$90.37**	**$94.12**

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Revenues	**RATE SAVINGS**		**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Ave CCA Rate, $/MWh		*$0.0*	*$66.1*	*$68.0*	*$70.8*	*$72.3*	*$74.3*	*$76.3*	*$78.2*	*$79.7*	*$86.9*
Rate Revenue			$79,265,581	$155,995,311	$162,735,542	$165,765,376	$169,634,817	$173,984,674	$177,448,282	$180,034,840	$195,448,989
Net Uncollectibles			($198,164)	($389,988)	($406,839)	($414,413)	($424,087)	($434,962)	($443,621)	($450,087)	($488,622)
Other Revenue (Loans)		$21,193,929									
Interest	**0.00%**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue		$21,193,929	$79,067,417	$155,605,322	$162,328,704	$165,350,963	$169,210,730	$173,549,713	$177,004,661	$179,584,753	$194,960,367
Expenses											
Cost of Power		$0	($54,770,145)	($110,019,602)	($111,302,740)	($112,073,902)	($105,029,841)	($115,224,647)	($118,590,125)	($123,140,226)	($127,963,917)
Cost of Capacity (including losses)		$0	($3,947,984)	($9,901,884)	($10,710,959)	($10,882,264)	($12,337,498)	($24,118,297)	($22,490,082)	($21,375,467)	($20,720,568)
O&M/A&G Costs		$0	($6,957,248)	($10,761,048)	($11,489,059)	($12,096,719)	($9,965,018)	($10,175,208)	($10,393,711)	($10,604,678)	($10,815,038)
Other Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses		$0	($65,675,377)	($130,682,535)	($133,502,757)	($135,052,885)	($127,332,357)	($149,518,153)	($151,473,918)	($155,120,370)	($159,499,523)
Unleveraged Free Cash Flow		$21,193,929	$13,392,040	$24,922,788	$28,825,947	$30,298,078	$41,878,374	$24,031,560	$25,530,743	$24,464,382	$35,460,844
Debt Service			($1,959,941)	($7,839,765)	($7,839,765)	($7,839,765)	($7,839,765)	($5,879,824)	$0	$0	$0
Leveraged Free Cash Flow		$21,193,929	$11,432,099	$17,083,022	$20,986,181	$22,458,313	$34,038,608	$18,151,735	$25,530,743	$24,464,382	$35,460,844
Working cash on hand		$21,193,929	$32,626,027	$39,563,751	$59,887,512	$82,345,825	$116,384,433	$134,536,168	$160,066,912	$184,531,294	$219,992,138
Minimum Cash on hand			*$19,766,854*	*$38,901,331*	*$40,582,176*	*$41,337,741*	*$42,302,683*	*$43,387,428*	*$44,251,165*	*$44,896,188*	*$48,740,092*
Cash (to)/From reserve			($10,145,298)	($662,421)	($10,393,660)	($232,519)	$0	($1,875,799)	$0	$0	($615,232)
End of Year Cash		**$21,193,929**	**$22,480,729**	**$38,901,331**	**$49,493,852**	**$82,113,305**	**$116,384,433**	**$132,660,369**	**$160,066,912**	**$184,531,294**	**$219,376,906**
			$2,713,875								
Reserve Fund Adjustment		**15%**									
Target		$0	$10,145,298	$20,778,345	$21,201,378	$21,433,897	$20,275,818	$23,309,697	$22,721,088	$23,268,056	$23,924,928
Reserve Fund Adjustment											
Potential Reserve Addition		*$0*	*$10,145,298*	*$10,633,047*	*$10,393,660*	*$232,519*	*-$1,158,079*	*$1,875,799*	*-$588,609*	*-$41,641*	*$615,232*
Reserve additions (Subtractions)		$0	$10,145,298	$662,421	$10,393,660	$232,519	$0	$1,875,799	$0	$0	$615,232
Reserve fund total		**$0**	**$10,145,298**	**$10,807,719**	**$21,201,378**	**$21,433,897**	**$21,433,897**	**$23,309,697**	**$23,309,697**	**$23,309,697**	**$23,924,928**