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"To enrich lives through effective and caring service"

July 28, 2016

To: Supervisor Hilda L. Solis, Chair
Supervisor Mark Ridley-Thomas
Supervisor Sheila Kuehl
Supervisor Don Knabe
Supervisor Michael D. Antonovich

From: Dave Chittenden
Chief Deputy Director

BOARD MOTION OF SEPTEMBER 15, 2016, ITEM NO. 6 - FINAL REPORT BACK ON THE PRELIMINARY TECHNICAL ANALYSIS ON THE FEASIBILITY OF A COUNTYWIDE COMMUNITY CHOICE AGGREGATION PROGRAM FOR ELECTRICAL POWER PROCUREMENT

Final Report Back

This memorandum along with the attached business plan constitute the Final Report Back in response to your Board's instructions on September 15, 2015, for the Director of the Internal Service Department (ISD) and the Chief Executive Officer (CEO) to provide a preliminary technical analysis on the feasibility of establishing a Community Choice Aggregation (CCA) program for electrical power procurement for County unincorporated areas, with potential expansion to other public agencies and private customers.

Background

Initially, on March 17, 2015, your Board instructed ISD's County Office of Sustainability to investigate the feasibility of establishing an electrical power purchase CCA program in the County. On June 24, 2015, ISD submitted the report-back to that motion.

On September 15, 2015, your Board instructed ISD and CEO to retain a CCA consultant to provide a feasibility study addressing the following areas:

a. County Unincorporated. A preliminary technical analysis of the feasibility of establishing a CCA in the County's unincorporated areas, including the costs (start-up, short-term and long-term), benefits and risks to the County;

b. Countywide. An analysis of the financial viability of a local CCA, including an assessment of energy supplies required for all customer classes (residential, commercial, industrial users) and the availability of sufficient green energy supplies;

c. CCA versus SCE. A preliminary analysis that compares end-user monthly rates across rate classes and levels of green energy desired between a CCA and Southern California Edison, our local investor-owned utility; and

d. Issues, Key Decision Points & Next Steps. Key decision points, next steps and issues that the Board must consider before making a decision to move forward with the formation of a Los Angeles County CCA, including options for financing start-up and initial operational costs, a proposed governance structure, potential green energy and rate tiers and planning, implementation and rollout timelines.

Pending submission of this Final Report Back, your Board additionally instructed ISD and CEO to create, lead, and convene regular meetings of a CCA Implementation Workgroup, with representatives from the County, other jurisdictions that have shown interest in joining a County CCA program, organized labor, and other stakeholders, to:

a. Assess the feasibility of other jurisdictions joining a County CCA program;

b. Provide information and guidance to other jurisdictions on the potential timeline and necessary steps to join a County CCA; and

c. Determine if a County CCA can advance workforce training and hiring objectives that align with County goals.

Per your Board's direction, as these actions progressed, ISD submitted interim status reports to your Board on November 14, 2015, February 8, 2016, and April 6, 2016.

The Business Plan

Per your Board's direction, ISD engaged CCA consultants to conduct the CCA preliminary technical analysis and feasibility study.[1] Their resulting work product is the *County of Los Angeles Community Choice Energy Business Plan* (Business Plan), which is Attachment A hereto and an integral part of this Final Report Back.

This memorandum does not attempt to reiterate the detailed analysis from the Business Plan, but instead summarizes the results and incorporates the underlying analysis by cross-reference to the Business Plan.[2] The terms Community Choice Aggregation or CCA and Community Choice Energy or CCE are used synonymously throughout this report and the Business Plan.[3]

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[1] The Business Plan was prepared by EES Consulting, Inc., in conjunction with Bevilacqua-Knight, Inc., and includes a funding option appendix prepared by Public Financial Management, Inc.

[2] For example, [BP 2, 4] would be a cross-reference to pages 2 and 4 of the Business Plan.

[3] The use of the terms Community Choice Aggregation and CCA reference these types of programs as defined by California legislation authorizing the formation of CCAs and as used by the California Public Utilities Commission in their role as regulators of CCAs. The terms Community Choice Energy and CCE are being adopted throughout California as a more "user-friendly" term for these programs.

The Business Plan contains the requested technical analysis and financial viability assessment. It also estimates CCA power supply costs, administrative costs, electric loads, and future retail rates and compares them to the incumbent rates offered by Southern California Edison (SCE). These forecasted rates and other analyses are examined to determine if the proposed County CCA can offer competitive rates, better products and superior customer service while also improving the environment and creating local jobs.

The Business Plan includes an Executive Summary which concludes that the formation of a CCA in Los Angeles County is financially viable and would yield considerable benefits for the County's residents and businesses [BP 2-7]. These benefits would include at least a four percent lower rate for electricity than is charged by SCE [BP 4] with roughly twice the amount of renewable resources utilized [BP 4-5]. Upon achievement of various implementation phases of a County CCA, the program would significantly reduce GHG emissions in the region [BP 6-7], add hundreds of jobs, generate millions of dollars in additional Gross Domestic Product [BP 5-6], and give the County and its residents local control over their power supply and energy efficiency programs.

Finally, the Business Plan opines that there is no reasonable set of risk-related circumstances that would result in the County CCA rates being higher than SCE's comparable rates [BP 7, 60].

Three-Phase Implementation

A cornerstone to the analysis in the Business Plan is that implementation of a County CCA should be done through three progressive phases [BP 7, 14-15]. In particular:

- Phase 1 would commence as early as January 2017, and would provide service only to County municipal facilities located in County unincorporated areas. Other cities' municipal facilities could be eligible for Phase 1 services if they were to timely join LACCE.[4]

- Phase 2 would commence as early as July of 2017, and expand service to include all County unincorporated area electric ratepayers. Other cities' electric ratepayers could be eligible for Phase 2 service if they were to timely join LACCE.

- Phase 3 would commence at a date yet-to-be-determined, and would expand service to include all cities' electric ratepayers, depending on if and when the cities choose to join LACCE.

A proposed LACCE Implementation Schedule is included in the Business Plan [BP 56], and is also provided with this memorandum as a separate attachment (Attachment B - *LACCE Implementation Schedule*).

Beginning operations with the scope limited to County municipal facilities only in Phase 1 would have several benefits. For example, experiences from other CCAs already operating in California suggest that glitches with data transfer and customer billing-system interfaces with SCE will likely occur and take some time to correct. Using County municipal accounts only

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[4] Los Angeles Community Choice Energy or LACCE is the CCA program name used in the Business Plan.

during the initial phase would mitigate customer service concerns, as we--the County—would be our only customer [BP 64]. These County accounts are managed by ISD's County Office of Sustainability, and any data and billing problems could be more easily reconciled and resolved through this single-point of contact.

Phase 2 would expand services to all ratepayers in unincorporated County areas. The County has no control over cities joining LACCE as cities would become members of the program through individual Council resolutions. Cities may be more likely to join a CCA that is already operating and has operating experience.

Los Angeles Community Choice Energy (LACCE) Benefits Summary

Lower Rates

California mandates that SCE and other utilities achieve 33% renewable resources content in their power supply portfolios by 2020. SCE is currently at approximately 28% renewables (base rate) in their power supply and an LACCE rate with an equivalent 28% renewables content would be 5% lower than SCE's base rate. The Business Plan also forecasts that an LACCE rate with 50% renewables content would be 4% lower than SCE's base rate and an LACCE rate with 100% renewables content would be only 6% higher than SCE's base rate. [BP 3-4, 43-46]

Renewable Resources and Greenhouse Gas Reductions

The higher levels of renewable resources in the LACCE rates (50% and 100%) would have significant impacts on GHG reductions in the region. Serving only County unincorporated area customers under the 50% renewables rate would reduce GHG emissions by an estimated 500,000 tons of carbon annually. For comparison purposes, GHG responsibility for the County's municipal operations (*e.g.*, buildings' energy use, vehicle fuels) is about 1 million tons of carbon annually. The LACCE base renewables rate in unincorporated County would offset half of the County's municipal operations GHG responsibility.

At full implementation (i.e., County and all eligible cities enrolled in LACCE, and under the 50% renewables rate) LACCE would reduce overall GHG emissions in the County by approximately 7%. This GHG reduction would be roughly double at the 100% renewables rate [BP 6-7, 47-48].

Economic Development and Jobs

For unincorporated County areas under the LACCE 50% renewables rate, ratepayers would save an estimated, total $20 million annually in utility bill payments. The Business Plan uses a standard economic development model (IMPLAN) which predicts that that $20 million savings would result in over 200 jobs created through direct, indirect and imputed impacts (impacts as a result of the new spending in the economy). At full LACCE implementation, these results could increase by up to seven times. [BP 5-6, 48-51]

Additionally, the LACCE could seek to support private sector distributed generation projects at the local and regional level, instead of procuring all power needs from large utility-scale distributed generation projects outside the County, Southern California, or the State [BP 46-48]. For example, with the typical 50MW (megawatts) solar project (which could be built in the

County; or alternatively, 50 1-MW projects), the economic modeling predicts around 700 construction and other service jobs would be created.

Local Control and Energy Management

LACCE would provide the County and cities choices in retail rate offerings to their ratepayers. The Business Plan provides three options on renewable power content strictly for comparison to SCE's current, base rate [BP 46]. LACCE, working with the County and cities, may determine other rate options be made available. Accordingly, it is conceivable that different rate offerings could be made for individual cities or groups of cities.

LACCE would be eligible to acquire funding for design of its own end-user programs incorporating measures such as energy efficiency, retail distributed generation, energy storage, water efficiency and electric vehicle charging into comprehensive, user-friendly, one-stop program offerings. LACCE would also benefit from having the Southern California Regional Energy Network (SoCalREN) already operating in the County (and serving all eligible cities) with energy efficiency programs. SoCalREN could easily and cost-effectively become the end-user program delivery model for LACCE. [BP 46-47]

Risks Assessment and Mitigation

The Business Plan identifies risks associated with operation of the LACCE program and discusses their mitigation and likely impacts. It also includes impacts on benefits due to sensitivity analyses around forecasted rates under highly negative scenarios for each risk. The major risk is that LACCE's rates could move higher than SCE's and the LACCE would lose revenue as customers migrate back to SCE. Other risks involve major power market price changes, customers moving back to SCE for other reasons, and regulatory/legislative risks associated with operation of CCAs in State. [BP 3, 12-13, 52-55]

The Business Plan concludes that these risks are manageable, particularly since LACCE's proposed rates are based on conservative estimates of the factors identified which impact LACCE and SCE rates [BP 3-4, 60]. Basically, LACCE's rates may approach SCE's rates if the wholesale, natural gas-based power market goes even lower from its current, historically low prices seen today and for several years in the past. Also, LACCE's rates may approach SCE's if SCE's rates are reduced dramatically. Currently, SCE does not forecast any reductions in their rates. [BP 52-55]

Retention of customers should not be a significant risk if LACCE's rates are lower than SCE's and/or provide rate choices not offered by SCE. It is assumed that some customers will proactively opt out of LACCE, preferring to stay with SCE. The Business Plan's customer retention rates used for rate modeling are based on actual retention rates seen in other CCAs [BP 14-15]. Also, LACCE's calculated electric rates use even more conservative numbers than seen elsewhere in the State.

Given the proliferation of CCAs in the State, any regulations or legislation that would harm CCA viability would seem unlikely, especially given the heightened awareness of potential regulatory and legislative issues around CCA by all CCA stakeholders [BP 55, 61].

Proposed LACCE Implementation Schedule and Key Activities

Board Acceptance of Business Plan

The details in the Business Plan allow your Board to determine whether to initiate the LACCE program and allows other cities' to determine whether to join LACCE or develop their own CCA(s). The Business Plan will be provided to the eligible cities within the County, most likely through their Council of Governments or other groups. The Business Plan also will be used to begin more comprehensive outreach to LACCE stakeholders including organized labor, environmental advocacy groups, technical service providers, financing providers, State energy regulators, community groups, and others.

A power point presentation with an overview of the Business Plan has been prepared and will be used for briefing your Board Offices, COGs, and cities, as well as other stakeholder groups. These briefings are a continuation of ongoing outreach, and will be conducted after the Business Plan has been submitted.

LACCE Technical Service Providers

A Request for Statement of Qualifications has been issued by the LACCE technical consultants seeking information for two, critical service providers for LACCE:

- A full services power provider who will procure wholesale power, schedule power delivery into the State transmission system (grid), provide all ancillary power supply services that support the State's grid operations, and provide all necessary power procurement reporting.
- An LACCE data manager who will collect, reconcile and provide all data to the wholesale power services provider and to SCE to ensure customer bills are accurate, customer bill payments are collected, and wholesale power providers are paid.

The LACCE technical team will evaluate these offerings and will work with proposers to identify a pool of service providers. Upon direction from your Board, ISD or, if operational, the LACCE JPA, would negotiate and execute agreements with these and other needed service providers for Phase 1 operations.

LACCE Financing

The LACCE program would require about $10 million in start-up capital which will cover establishing the LACCE operations, procuring the first months of wholesale power under Phase 1, and paying for LACCE expenses during the 2 to 3 month lag between provision of power to LACCE customers and receipt of revenues from SCE for these customers. The Business Plan serves as a key document for informing the investment community about LACCE's operations and revenue viability. The Financing Section of the Business Plan indicates that a start-up loan can be acquired from a third party lender but it will likely be at relatively high market rates (5.5% over two years was used in the LACCE financial model) due to the nascent nature of LACCE. The LACCE financial model includes paying off this loan after two years of operation. COS has engaged an energy programs financial advisor who will reach out to the financial community to determine lenders' appetites for financing LACCE's Phase 1 and Phase 2 operations with or without support from the County as described below. [BP 62-66]

$1.5 million would be needed for expenses through calendar year 2016 to complete LACCE start-up activities. Thereafter, under LACCE Phase 1 initial operations, about $8.5 million would needed for labor, consultants, and initial power procurement. A more detailed description of these initial needs is included as an attachment (Attachment C – LACCE Start-up Budget).

Alternatively, other CCAs throughout the State have commenced operations using local government funding in the form of a loan with CCA operating revenues dedicated to paying off that loan. As indicated in the Business Plan, this type of internal loan from the County could similarly be repaid by LACCE revenues. [BP 64-65]

Other options for the County in providing LACCE financial and credit support include: establishment of an escrow account to "backstop" a lender's risk exposure, and/or provision of an agreement to not opt its Phase 1 accounts out of LACCE for the period of a loan [BP 65].

There are benefits to the County providing a loan or other credit support to LACCE but the initiation of LACCE is not seen to be dependent on this internal support.

LACCE Governance

A proposed organizational chart for CCA operations is included and discussed in the Plan. Phase 1 CCA operations, for County municipal buildings in unincorporated areas only, would be governed solely by the County, and run through ISD's County Office of Sustainability. [BP 2, 11, 36-39]

For other public agencies to join the CCA in subsequent phases, a joint powers authority (JPA) would be created. [*Public Utilities Code* §§ 331.1(b), 366.2(c)(12); *Government Code* § 6500, *et seq*.].

As a newly created and independent public agency, the JPA would be governed by its own Board of Directors. Unless your Board of Supervisors were to instruct otherwise, ISD recommends that the County would maintain a majority and controlling vote on the JPA Board. Depending on the number of other JPA members, other Director positions would be filled by some or all of the other member agencies, in direct and/or representative capacities.

The likely scope of non-County participation in any subsequent program phases is unknown at this time. But at your direction, ISD would continue to explore third-party public agency participation concurrently with Phase 1 start-up operations.

CCA Technical Team Next Steps

At your Board's direction, the LACCE technical team would continue using remaining technical study funds authorized by your Board to develop the CCA program with the following activities:

- Providing support to the Board Offices, COGs and cities in presenting and explaining development and outcomes of the Business Plan;

- Submitting necessary documents to SCE to support their preparation for working with LACCE on Phase 1;

- Submitting necessary documents to the CPUC, including the CPUC's required Implementation Plan (which is substantially completed), to support their review and approval of LACCE which is required for operations;

- Supporting the financial advisor's activities in identifying possible external and internal Phase 1 and Phase 2 financing sources;

- Providing limited outreach and education to other LACCE stakeholders and interested parties, particularly those who the County would seek to publicly advocate for LACCE (e.g., non-profit environmental groups, organized labor, academia, ratepayer interest groups, consumer protection agencies, and business representatives, etc.);

- Negotiating and executing (as directed by the Board) agreements with technical services providers.

Additional Next Steps

At your Board's direction, the CEO, County Counsel, and ISD, as more particularly tasked below, would initiate the following next steps to prepare for a potential CCA implementation:

- CEO and ISD to validate the technical feasibility report in the Business Plan, including start-up costs, sources of funding, and financial viability;

- County Counsel to work with CEO and ISD to explore appropriate governance models and provide options to your Board as non-County public agencies express interest in joining a County CCA; and

- ISD to continue to provide outreach to non-County public agencies.

Conclusion

The benefits to be derived from operation of the LACCE program are documented in the Business Plan and described in this memorandum and attachments. As also described, the risks associated with LACCE operations are projected to be manageable and unlikely to materialize. Under Phase 1, LACCE would gain operating experience working through business relationships with SCE, technical service providers, and cities and other stakeholders. To the extent that LACCE grows with other cities, the benefits for the region of lower utility costs, reduced GHG production, and initiation of beneficial local/regional clean energy programs would increase.

Successful CCAs are already operating in Marin and Sonoma Counties, in San Francisco City and County, and in the City of Lancaster. In Southern California, CCAs are being investigated by Ventura and Santa Barbara Counties (jointly) and in Riverside and San Bernardino Counties (jointly). CCAs are also being developed in Counties along California's central coast and in large Counties such as Santa Clara and Alameda; Humboldt County is exploring a CCA for the north coast region. The City of San Diego is leading CCA efforts in that region.

CCAs are now proving to be a critical component in the State's policies to reduce greenhouse gas emissions and to transform the energy industry into one that enhances the use of clean energy, helps accelerate the development of the electric grid of the future, and provides diversity and competition into the provision of traditional monopoly energy services.

Given the County's leadership in regional energy matters, individually as well as working with other energy stakeholders, it would be appropriate for the County to now develop its own CCA, the Los Angeles Community Choice Energy Program, to serve unincorporated areas and any eligible and interested city within the County.

If you have any questions regarding this matter, please contact me at (323) 267-2103, via email at dchittenden@isd.lacounty.gov or you may contact Howard Choy at (323) 267-2006, via email at hchoy@isd.lacounty.gov.

DC:HC:JG:sg

Attachments

c: ISD Board Deputies
Chief Executive Officer
Chief Operating Officer
Executive Office, Board of Supervisor
County of Sustainability Council

ATTACHMENT A

County of Los Angeles

County of Los Angeles
Community Choice Energy

Business Plan

June 30, 2016

Prepared by:

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June 30, 2016

Mr. Howard Choy
County of Los Angeles
Energy Management Division
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Los Angeles, CA 90063

SUBJECT: County of Los Angeles Community Choice Energy (LACCE) Business Plan

Dear Mr. Choy:

Please find attached EES Consulting, Inc.'s (EES) Community Choice Energy Business Plan (Plan) for the County of Los Angeles (County). This Plan represents the work product of EES and Bki in evaluating the prudency of implementing a Community Choice Energy organization for the County.

We want to thank you and your staff for your assistance in preparing this Plan. It has been a pleasure working with you on this project.

Please contact me directly if there are questions or if we may be of any further assistance.

Very truly yours,

Gary S. Saleba

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President

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Executive Summary

Background

The California legislature passed AB 117 in 2002 (amended in 2011 by SB 790) allowing all Cities, Counties, or groups of Cities and Counties to provide an electric power supply source to customers within their jurisdictions that are currently served by Southern California Edison, Pacific Gas & Electric or San Diego Gas & Electric. Community Choice Aggregation (CCA) or Community Choice Energy (CCE) is a customer opt-out program where the CCA provides power supply and behind the meter services, and the incumbent IOUs provide transmission and distribution (wires) service.

This Business Plan (Plan) evaluates the prudency of forming a CCA within the County of Los Angeles (County), the Los Angeles Community Choice Energy (LACCE). The proposed LACCE will provide power supply and behind the meter services, and Southern California Edison (SCE) will provide transmission and distribution services. Customers are part of the LACCE program until they proactively opt-out. This Plan estimates LACCE's power supply costs, administrative costs, electric loads, and future retail rates and compares LACCE's rates to the incumbent SCE. These forecast rates are compared to determine if the proposed LACCE can offer competitive rates, better products and superior customer service while also improving the environment and creating local jobs.

Description of LACCE

The proposed LACCE may include the unincorporated areas of the County and a number of Cities within the County. The unincorporated County average annual energy is 440 aMW (average Megawatts) and 900 MW peak while the total County potential service area average annual energy is estimated at 3,000 aMW and 7,000 MW peak. Energy consumption for the entire County area served by SCE is equal to more than 30 percent of SCE's total retail load.

For this Plan, it is assumed that service will be offered to customers in three phases. Phase 1 will include the County's own municipal facilities residing within the unincorporated County areas. In Phase 2, all customers located in the unincorporated County will be included in LACCE. Finally, service to customers from the Cities within the County will begin under Phase 3. Exhibit ES-1 summarizes this phased approach to forming LACCE, and the number of customers and amount of load attendant with each phase.

Exhibit ES-1 Participation Schedule						
Phase	**Start**	**Eligibility**	**Customer Accounts**	**Peak Load (MW)**	**Average Load aMW**	**LACCE Annual Revenues**
Phase 1	January 2017	LA County Facilities within Unincorporated Area	1,728	40	20	$25M
Phase 2	July 2017	All Customers in Unincorporated LA County	306,930	900	440	$180M
Phase 3	To Be Determined	All Individual Cities	1,497,747	7,000	3,000	$1,200M

Depending on the interest from Cities located in the County, Phase 1 and Phase 2 may also include customers from individual Cities. However, because of the number of Cities and the size of their associated loads, a phasing of implementation was assumed for this Plan. This phasing strategy enables LACCE to manage any start-up and operational issues before full scale operations are undertaken. In addition, this phasing strategy will allow LACCE's third party electricity suppliers, scheduling agents and data management entities to ramp up power supply procurement and bill processing over several months. Because it is not yet clear which Cities are interested in joining LACCE, this Plan explores the prudency of the first two phases being undertaken over a 20-year forecast period. It is anticipated that the results of this Plan are scalable as additional Cities join LACCE. Adding more customers than assumed in the Plan will increase revenues and further reduce LACCE rates.

By the end of Phase 2, LACCE is projected to serve a potential of over 300,000 retail customers and have annual electricity sales potential of over 3,800 GWh (Gigawatt-hours). Annual revenues to LACCE during Phase 2 operations are projected to be approximately $180 million.

Governance

The feasibility, analysis and development of LACCE is currently being conducted by the Office of Sustainability within the County's Internal Services Department. While LACCE could, in theory, be an organization operated within the County's existing governance, it is anticipated that a JPA will be formed to provide the legal structure of LACCE. A JPA provides a more flexible framework for LACCE and historically has been the preferred structure for an organization like LACCE. Additionally, a JPA provides financial risk mitigation for its local government members.

Given the above, a key next step in the formation of LACCE is the creation of the JPA (created when two jurisdictions agree to join the JPA). Initiating LACCE operations will then require a governing authority to execute service contracts for LACCE formation and operations.

Alternatively, while a JPA is being finalized and implemented, the Office of Sustainability could manage Phase I operations of LACCE, if directed by the Board of Supervisors.

Risks

All businesses face risks and uncertainty. For LACCE, the major risks will be operational and regulatory. These risks are dealt with extensively later in the Plan. In summary, the Plan concludes that these risks are manageable and that no reasonable set of circumstances will result in LACCE's rates being higher than SCE's for comparable products.

Plan Results

This Plan evaluates the cost and resulting rates of operating LACCE, and compares these rates to a rate forecast for SCE. The analysis begins with a 20-year forecast of electrical loads and customers, incorporates several power supply resource portfolio options, and allows for the sensitivity testing of input assumptions. LACCE customers will see no obvious changes in electric service other than a lower price and increased renewable resources in their power supply resource mix. Customers will pay the power supply charges set by LACCE and no longer pay the costs of SCE power supply.

In addition to paying LACCE's power supply rate, LACCE customers will pay the SCE delivery (wires) rate and all other non-power supply related charges on the SCE bill to include Franchise Fees and Utility User Taxes.

LACCE will establish rates sufficient to recover all costs related to operation of the CCE. It is anticipated that LACCE's rate designs initially will mirror the structure of SCE's rates so that rates similar to SCE's can be provided to LACCE's customers. In setting rates, the Plan's financial analysis assumes the customer phase-in schedule noted above and assumes that the implementation costs are largely financed via a start-up loan.

The first consequence for forming LACCE is the retail rate impact as illustrated on ES-2. ES-2 shows SCE's current total bundled rates of 28 percent renewable power compared to three LACCE rate options. Bundled rates are the "all in" price for electricity delivered to the customer's meter. The Plan's Resource Portfolio Standard (RPS) rate assumes renewable energy is 28 percent of LACCE's initial power supply portfolio and increased per the State's RPS mandate.

For reference, the column headers noted on ES-2 are summarized below.

- RPS Bundled – LACCE rates with the same share (28 percent) of renewables as SCE's current power supply.
- 50% Green Bundled Rate – LACCE rates with 50 percent renewable power.
- 100% Green Bundled Rates – LACCE rates with 100 percent renewable power.

A rate schedule comparison of LACCE's rates and SCE's rates follows.

Exhibit ES-2 Indicative Rate Comparison in ¢/kWh					
Rate Class	**Customer Type**	**SCE Bundled Rate***	**LACCE RPS Bundled Rate**	**LACCE 50% Green Bundled Rate**	**LACCE 100% Green Bundled Rate**
Residential	Domestic	17.1	16.2	16.4	18.2
GS-1	Commercial	16.6	15.7	15.9	17.7
GS-2	Commercial	15.8	15.0	15.2	16.9
GS-3	Industrial	14.5	13.8	13.9	15.5
PA-2	Public Authority	12.6	12.0	12.1	13.4
PA-3	Public Authority	10.4	9.9	10.0	11.1
TOU-8 Secondary	Domestic	13.1	12.4	12.6	14.0
TOU-8 Primary	Commercial	11.7	11.1	11.2	12.5
TOU-8 Substation	Industrial	7.5	7.1	7.2	8.0
Total LACCE Rate Savings			5.4%	4.1%	(6.3%)

*SCE bundled average rate based on Table 3 in Advice 3319-E-A.

As can be seen above, the LACCE RPS residential rate is 0.9¢/kWh or 5.4 percent lower than what SCE currently offers with an equal amount of renewable power (28 percent). The LACCE residential rate with 50 percent renewable power (compared to SCE's 28 percent) is 0.7¢/kWh or 4.1 percent lower for roughly twice the amount of green renewable power. The LACCE residential rate with 100 percent green power (compared to SCE's 28 percent) is 1.1¢/kWh or 6.3 percent higher, but this additional amount comes with almost four times more renewable power than the comparable SCE rate.

As an alternative to its standard rates with 28 percent renewable power, SCE also offers rates which feature 50 percent and 100 percent renewable power. For the residential customers, SCE estimates energy costs to be 3.5 cents per kWh higher for each kWh served on the green rate. The LACCE rates for 50 percent and 100 percent renewable power for residential customers are therefore estimated at 12-13% percent lower than SCE's.

The rates calculated under this Plan are for comparison to SCE rates only. Under formal operations, the LACCE governance will determine the actual rates to be offered to customers. For example, LACCE may decide to offer the 50% renewables rate as the base tariff to customers if the environmental benefits far outweigh a minor difference in cost compared to the RPS base case.

Finally, it should be noted that these rate comparisons assume all savings will go towards rate reductions. It is likely that the LACCE governing body may opt to place some of these savings into a financial reserve account for use at other times when needed and/or to accelerate the payoff of start-up and initial operations financing.

Renewable Energy Impacts

A second consequence of forming LACCE will be an anticipated increase in the proportion of energy supplied by renewable resources used by LACCE customers. The Plan includes procurement of renewable energy sufficient to meet 50 percent or more of LACCE customer's electricity needs at start up. The majority of this renewable energy will be met by renewable energy purchased on the wholesale market or newly constructed renewable resources. By 2020, SCE must procure a minimum of 33 percent of its customers' annual electricity usage from renewable resources due to the State's RPS mandate and the Energy Action Plan requirements of the California Public Utilities Commission (CPUC). In contrast, LACCE customers will target 50 percent renewable power by 2017, which will come from new and some local renewable resources.

Energy Efficiency Programs

A third consequence of the Program will be an increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by SCE will not change as a result of LACCE. LACCE customers will continue to pay the Public Goods Charges to SCE. This charge funds energy efficiency programs for all customers, regardless of power supply provider. The energy efficiency programs ultimately planned by LACCE will be in addition to the level of energy efficiency investment currently provided by SCE. Thus, LACCE has the potential to increase energy savings with an attendant reduction in emissions due to expanded energy efficiency programs.

LACCE will likely establish a program which offers a combination of retail tariffs, rebates, incentives and other bundled offerings intended to increase customer participation in demand-side management programs including: renewable distributed generation, energy storage, energy efficiency, demand response, electric vehicle charging, and other clean energy benefits defined as Distributed Energy Resources (DER). LACCE will work with State agencies and SCE to promote deployment of DERs in specific and targeted locations throughout SCE's distribution grid, and preferably within the County, in order to help support efficient grid operations and maintenance as part of the development of the future "smart grid."

The Southern California Regional Energy Network (SoCalREN), administered by the Office of Sustainability and authorized by the California Public Utilities Commission (CPUC) as an independently administered energy efficiency program in 2012, will serve as a platform for providing the services described above as it already receives funding under the CPUC's Energy Efficiency Program and is active in current CPUC proceedings designed to accelerate the implementation of local DERs.

Economic Development

The fourth consequence of LACCE will be significant economic development. So far, the analyses contained in this Plan focused on the direct effects of forming LACCE. However, in addition to these direct effects, the formation of LACCE will create indirect economic effects. These include increased local investments, increased disposable income due to bill savings, and improved environmental and health conditions.

Exhibit ES-3 shows the economic impact resulting from $20 million in electric bill savings across the County. The $20 million rate savings represents the estimated bill savings per year achievable by LACCE once Phase 3 operations begin. Based upon a macroeconomic input/output model employed for this Plan, it is estimated that these savings will create approximately 211 additional jobs in the County and over $9.6 million in labor income. It is also estimated that the total value added will be approximately $15.9 million and output close to $24.2 million.

Exhibit ES-3 $20 Million Rate Savings Effects on County Economy				
Impact Type	**Employment**	**Labor Income**	**Total Value Added**	**Output**
Direct Effect	98.3	$3,674,939	$5,376,863	$7,099,612
Indirect Effect	10.4	$608,838	$1,057,593	$1,677,591
Induced Effect	102.1	$5,319,262	$9,472,599	$15,391,851
Total Effect	210.7	$9,603,040	$15,907,056	$24,169,054

In addition to increased economic activity due to electric bill savings, potential local projects can also create job and economic growth within the County. As an example of the macroeconomic activity caused by local DER deployment, this Plan assumes the installation of 50 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. Overall, the building of a 50 MW solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. It is anticipated that LACCE will ultimately install a number of larger local solar projects such as the one described. LACCE will need between 2,000 – 3,000 MW of solar at build-out. As such, the total economic benefit of LACCE's renewable resource could be 40 – 60 times those estimated above. Local clean projects development under LACCE may serve as a platform for accelerating local hiring programs and job training programs for underserved labor sectors and communities.

Green House Gas Impacts

The fifth consequence of forming LACCE will be significant environment benefits. The share of renewable power in SCE's power supply portfolio is currently 28 percent[1] and is scheduled to shift to 33 percent by 2020. LACCE is committed to reductions in greenhouse gas emissions. If LACCE achieves its 50 percent RPS target at start-up, GHG emissions reductions attributable to LACCE operations in 2019 will range from 289,080 to 505,890 tons CO_2 equivalent (CO_2e) per year relative to SCE's projected resource mix over the same period. Exhibit ES-4 details these reductions.

Exhibit ES-4 Baseline Comparison of GHG Reduction by LACCE			
	2017	**2018**	**2019**
Forecast Renewables (50% Renewables) LACCE (MWH) – Phase 2	1,438,275	1,459,854	1,459,854
LACCE RPS (MWH) – Phase 2	730,029	737,154	737,154
Additional Green Power (MWH)	708,246	722,700	722,700
CO2 reduction – Low (Metric Tons of CO_2e)	283,298	289,080	289,080
CO2 reduction – High (Metric tons of CO_2e)	495,772	505,890	505,890

[1] http://www.cpuc.ca.gov/RPS_Homepage/

These reductions in GHG emissions associated with LACCE operations are significant. Assuming only Phase 2 loads (all unincorporated County loads) are being met by LACCE, CO_2e emissions associated with in-County electricity use will be reduced by 1-2 percent. At full Phase 3 build-out, CO_2 emissions associated with in-County electricity use will be reduced roughly 12-25 percent by LACCE operations.

Summary

This Plan concludes that the formation of a CCA in Los Angeles County is financially prudent and will yield considerable benefits for the County's residents and businesses. These benefits include at least a 4 percent lower rate for electricity than is charged by SCE and roughly twice the amount of renewable resource deployment. With the achievement of Phase 2 operations, LACCE will reduce GHG emissions by as much as 500,000 tons of CO_2e per year, add hundreds of jobs, generate over $24 million in additional GDP, and give the County and its residents local control over their power supply and distributed energy resource programs. At full build-out (Phase 3), LACCE will reduce in-County generation-related greenhouse gases by as much as 25 percent and total GHGs in the County by 6%. Finally, there is no reasonable set of risk-related circumstances that will result in LACCE's rates being higher than SCE's rates for comparable products.

Introduction

Background

California's legislature passed AB 117 in 2002 (amended in 2011 by SB 790) allowing all Cities, Counties, or groups of Cities and Counties to provide electric service to customers currently served by Investor-Owned Utilities (IOUs). Community Choice Aggregation (CCA) is the legislative organization empowered to provide this service. A CCA is a customer opt-out program where the CCA provides power supply and behind the meter services, and the incumbent IOU provides transmission and distribution (wires) service. This legislation states that CCA will enable California to experience more competitive electricity rates, a more renewable power supply mix, and growth in local resources and associated economic activity. Currently, there are five CCAs operating in California and these utilities offer competitive rates for power supply that have a higher percentage of renewable resources. They have also proven to promote local economic activity and their associated benefits.

Several other California Cities and Counties are currently evaluating the feasibility of CCA formation within their jurisdictions. This information can be found in Appendix A.

There are several potential benefits of the CCA model in addition to competitive rates. Other benefits include local control over energy resources selection including renewable local projects, energy efficiency and a reduction in greenhouse gases (GHG). In addition, CCAs can minimize power supply rates and maximize renewable energy utilization with the attendant local jobs in the local community.

Objective

This Business Plan (Plan) evaluates the feasibility of forming a CCA within the County of Los Angeles (County) named the Los Angeles Community Choice Energy (LACCE). The proposed CCA will provide power supply and behind the meter services, and Southern California Edison (SCE) will provide transmission and distribution (wires) services. This Plan estimates LACCE's power supply costs, administrative costs, electric loads, and future retail rates for the proposed LACCE and incumbent Investor-Owned Utility (IOU), Southern California Edison (SCE). These forecast rates are compared to determine if the proposed LACCE can offer competitive rates, better products and superior customer service. A sound financial and operational foundation for LACCE must be achievable before the other desirable attributes of a CCA can be enjoyed.

LACCE Description

LACCE, as proposed, may include the unincorporated areas of the County and a number of Cities within the County. Unincorporated County average annual energy use is 440 aMW with a 900 MW peak while the total Plan area average annual energy use is estimated at 3,000 aMW with a 7,000 MW peak. Energy consumption for the entire LACCE area equals more than 30 percent of SCE's current retail loads.

For this Plan, it is assumed that service will be offered to customers in three phases. Phase 1 will include the County's own facilities residing within the unincorporated County areas. In Phase 2, all customers located in the unincorporated County will be included into LACCE. Finally, service to customers from the Cities within the County will begin under Phase 3 and after LACCE is completely operational. However, Cities that are ready to participate early will be eligible under Phases 1 and 2. Exhibit 1 summarizes this phased approach to starting LACCE and the amount of load attendant with each phase.

Exhibit 1
Participation Schedule

Phase	Start	Eligibility	Customer Accounts	Peak Load (MW)	Average Load (MWa)	LACCE Annual Revenues
Phase 1	January 2017	LA County Facilities within Unincorporated Area	1,728	40	20	$25M
Phase 2	July 2017	All Customers in Unincorporated LA County	306,930	900	440	$180M
Phase 3	To Be Determined	All Individual Cities	1,497,747	7,000	3,000	$1,200M

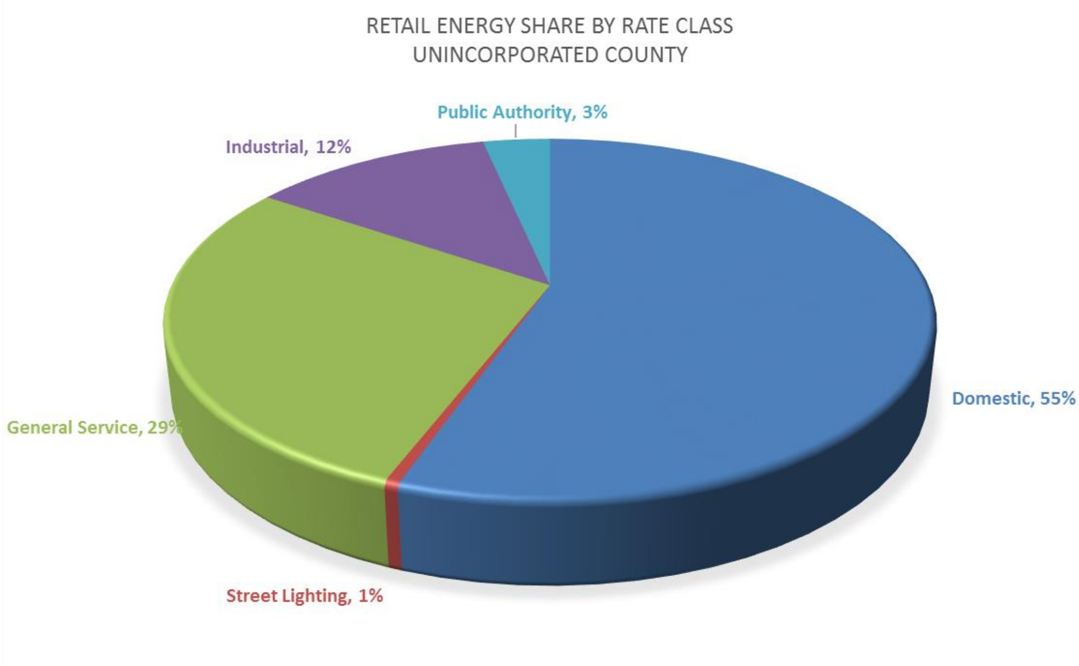
Customer Participation Schedule

Depending on the interest from Cities located in the County, Phase 1 and Phase 2 may include customers from individual Cities; however, because of the number of Cities and the size of their associated loads, a phasing strategy is assumed for this Plan. This phasing strategy enables LACCE to address any start-up and operational issues before full scale operations are undertaken. In addition, this strategy will allow LACCE's third party electricity suppliers, scheduling agents and data managers to ramp up their activities over several months.

Because it is not yet clear when Cities will join LACCE, this Plan explores the feasibility of only the first two phases. It is anticipated that the results of this Plan are scalable as additional Cities join LACCE. However, a few of the key statistics and benefits that LACCE provides have also been noted under full-scale participation of Phase 3. Additional load from other Cities will increase LACCE's revenues and lower overall rates.

By the end of Phase 2, LACCE is projected to serve a potential of over 300,000 retail customers and have annual electricity sales potential of over 3,800 GWh. Annual LACCE revenues at Phase 2 build-out are projected to be $180 million. At full build-out for the entire County, gross revenues of $1.2 billion are forecast. The breakdown of projected sales in Phase 2 by major customer class is shown in the following Exhibit 2.

Exhibit 2
Retail Energy Share by Rate Class



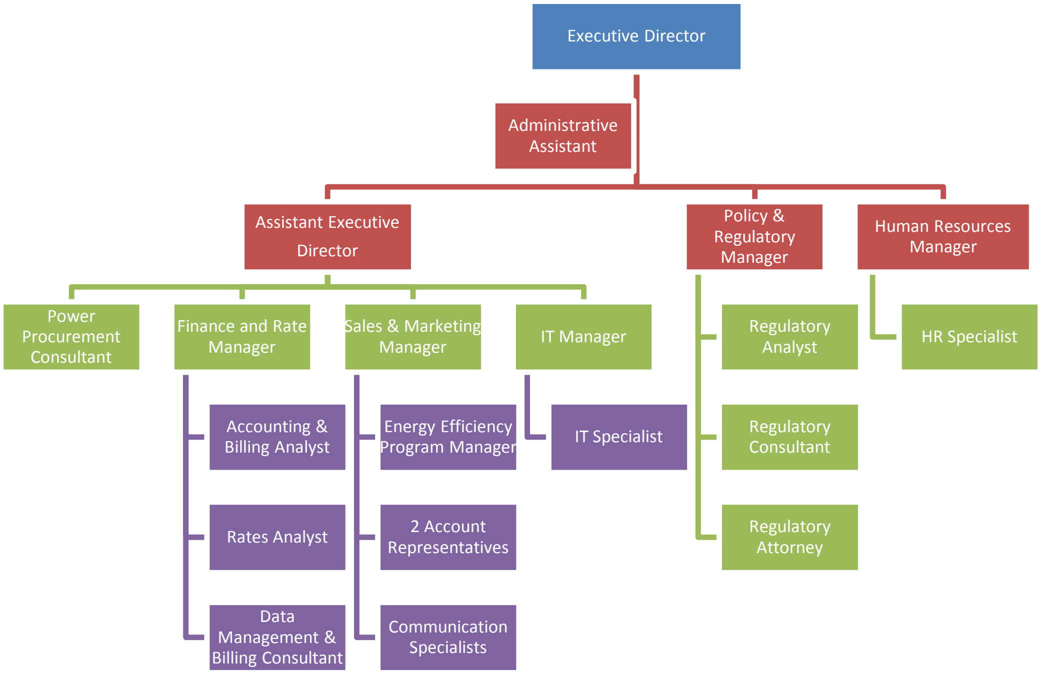
Summary of LACCE's Proposed Governance and Operations

In the future, LACCE will likely be operated under the terms of a Joint Powers Agreement (JPA), which will promote, develop, and conduct electricity-related projects and programs for the County's residences and businesses. The JPA agreement will dictate the governance provisions of LACCE. A description of LACCE operations and governance is described below.

LACCE activities will be overseen by the JPA's Board of Directors (Board). This Board will have primary responsibility for managing all aspects of LACCE programs. Operations of LACCE programs will be the responsibility of an Executive Director, appointed by LACCE's Board. The Executive Director will manage staff, contractors and third party providers, in accordance with the general policies established by the Board. LACCE has responsibilities over the functional areas of Finance, Legal/Regulatory, and Operations. LACCE will utilize a combination of internal staff and contactors. Certain specialized functions are needed within LACCE operations, namely those of electric supply and customer billing management.

If LACCE transitions most of its administrative and operational responsibilities to internally staffed positions sometime during Phase 2 operations, LACCE will have a full time staff of approximately 15 – 20 employees to perform its responsibilities, primarily related to program and contract management, legal and regulatory, finance and accounting, energy efficiency, marketing and customer service. Technical functions associated with managing and scheduling power suppliers and those related to retail customer billings will likely be performed by an experienced third party contractor. The proposed organization chart for LACCE is provided below.

Exhibit 3
Organization Chart



It is estimated that LACCE will need a bridge loan of roughly $10 million to initiate LACCE and provide the working capital needed in Phase 1. Working capital requirements will increase to approximately $40 million for Phase 2. Options for acquiring this funding are described later in the Plan.

Plan Methodology

This Plan evaluates the cost and resulting rates of operating LACCE and compares these rates to a SCE rate forecast. This pro forma 20-year feasibility analysis models the following cost components:

- Power Supply Costs:
  - Wholesale purchase
  - Renewable purchases
  - Procurement of resource adequacy capacity
  - Other power supply and charges
- Non-Power Supply Costs:
  - Start-up costs
  - LACCE staffing and administration costs
  - Consulting support
  - SCE and regulatory charges
  - Financing costs

- Pass-Through Charges from SCE:
  - Transmission and distribution charges
  - Power Cost Indifference Adjustment (PCIA) Charge
  - Other SCE non-bypassable charges

The modeled information above is used to determine the retail rates for LACCE. LACCE rates are then compared to the SCE projected rates for LACCE service area.

Plan Uncertainties

The results of this Plan are subject to uncertainties. These uncertainties are evaluated in the Plan's sensitivity analysis. The list below provides a discussion of the key uncertainties of this Plan.

- Market Price Forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this Plan are based on the best currently available information regarding future natural gas and electricity prices, and have been confirmed by recent wholesale power transactions in southern California. These types of forecasts vary over time. Thus, a range of market price forecasts are evaluated in the Plan's sensitivity analysis.
- Rate Forecasts – The Plan forecasts both LACCE and SCE rates over a 20-year study period. These forecasts are based on current information regarding inflation and other cost drivers. Unexpected impacts on rates are discussed in more detail in the Plan's sensitivity analysis.
- Forecasted Load and Customer Growth – The Plan bases the load forecasts on customer growth. Each of these forecasts includes a level of uncertainty. To illustrate the load uncertainty, low, medium, and high load forecasts are developed for the Plan's sensitivity analysis.
- Regulatory Risks – Unforeseen changes in legislation (California Public Utility Commission, State legislation and Federal Energy Regulatory Commission) may impact the results of this Plan. Sensitivities on these risks are also provided.

This sensitivity analysis shows that LACCE rate could be greater than SCE rates if:

- The PCIA becomes larger by orders of magnitude
- LACCE loads are much less than forecast
- Wholesale market prices are much less than current experience

Each of these three scenarios has a low risk of actually occurring. For example, wholesale market prices for natural gas/electricity are at all-time lows. The probability of any significant further lowering of these prices is judged to be very small. The PCIA level should be fairly stable going forward as regulatory remedies are in play to stabilize the PCIA. Additionally, the CCA vigilance in this area has increased markedly. A relatively high customer opt-out percentage has been assumed in this Plan as compared to those experienced by operating CCAs. It is very unlikely LACCE loads will not meet or exceed those assumed in the Plan. Finally, the California legislature promulgates energy legislation with some regularity. Most recently, SB 350 was passed which requires periodic filings by all utilities to document their respective power procurement strategies and requires all utilities to procure a large amount of power with contract terms greater than 10 years. While these new requirements may be viewed as overly prescriptive, they apply to all utilities and should not affect the relative competitiveness of LACCE vis-à-vis SCE.

Plan Organization

This Plan is organized into the following main sections:

- Load Requirements
- Power Supply Strategy and Costs
- LACCE Cost of Service
- Products, Services, Rates Comparison and Environmental/Economic Considerations
- Sensitivity Analysis
- Summary and Recommendations

These Appendices are referenced throughout the balance of this Plan.

Rates paid by LACCE customers will vary depending on load levels, power supply mix, power purchase strategy, stranded costs estimated via SCE’s Power Cost Indifference Adjustment (PCIA), and ultimately LACCE’s implementation strategy. This section of the Plan provides an overview of the forecast LACCE load levels. The other key areas noted above will be detailed in the remaining sections of the Plan.

LACCE JPA Membership Participation Rates

For the purpose of this Plan, it has been assumed that the development of LACCE will occur using a three-phase implementation structure. Phase 1 will include the County’s own facilities within the unincorporated County. Phase 2 will enroll all customers in the unincorporated County, while Phase 3 opens enrollment to all interested Cities within the County. Because the timing of Phase 3 is uncertain, this Plan examines the feasibility of a LACCE covering only unincorporated LA County (Phases 1 and 2). However, individual Cities could participate in LACCE starting in Phase 1 or Phase 2, if desired. This will require notification to LACCE of a City wishing to join that is early enough for proper power supply and data management issues to be resolved.

Exhibit 4 summarizes this phased approach to starting LACCE and the amount of load attendant with each phase.

Exhibit 4
Implementation Schedule

Phase	Start	Eligibility	Customer Accounts	Peak Load (MW)	Average Load (MWa)	LACCE Annual Revenues
Phase 1	January 2017	LA County Facilities within Unincorporated Area	1,728	40	20	$25M
Phase 2	July 2017	All Customers in Unincorporated LA County	306,930	900	440	$180M
Phase 3	To Be Determined	All Individual Cities	1,497,747	7,000	3,000	$1,200M

LACCE Customer Participation Rates

Before customers are served by LACCE, they will receive two notices from LACCE that will provide information needed to understand the terms and conditions of service from LACCE and explain how customers can opt-out, if desired. These notices will be provided 60 and 30 days before CCA launch. All customers that do not follow the opt-out process specified in the customer notices will be automatically enrolled into LACCE. Customers automatically enrolled will continue to have their electric meters read and will be billed for electric service by SCE. LACCE bill processed by SCE will show separate charges for power supply procured by LACCE, all other charges related to delivery of the electricity and other utility charges that will continue to be assessed.

Subsequent to commencement of service, customers will be given two additional opportunities to opt-out and return to SCE at 60 and 30 days after LACCE's launch. Customers that opt-out between the initial switchover date and the close of the post enrollment opt-out period will be responsible for LACCE charges for the time they are served by LACCE but will not otherwise be subject to any charges for leaving LACCE. Customers that have not opted-out within sixty days of switchover to LACCE service will be deemed to have elected to become a participant in LACCE.

This Plan anticipates an overall customer participation rate of 100 percent during Phase 1, as service is being offered to County facilities. For Phase 2, it is assumed that approximately 75 percent of residential customers and 65 percent of non-residential customers will remain with LACCE. These opt-out assumptions are conservative estimates when compared to participation rates in other CCAs. For operating CCAs in California, roughly 85 percent of the applicable customers have stayed with the CCA. A sensitivity analysis is performed around this retail customer participation rate assumption to illustrate the impact on LACCE rates of higher and lower participation rates.

Historical Consumption

SCE provided historical customer consumption and data for the County areas served by SCE. This SCE data included non-coincident and coincident peak demands for the different rate classes plus monthly kWh energy consumption. This data included information from all 82 CCA-eligible Cities within the County plus the County's unincorporated areas. These data inputs provided the basis for LACCE load forecasts. Exhibit 5 summarizes the rate schedules included in the SCE-provided data.

Exhibit 5
Rate Schedules Included in SCE Load Data

Rate Class	Included Rate Schedules	Rate Schedule Description
Residential	DOM-S/M	Domestic Service – Single-Family Dwelling or individually metered Single-Family Dwelling in a Multifamily Accommodation
	DOM-M/M	Domestic Service – Multifamily Accommodation – Residential Hotel – Qualifying RV Park
	DOM-S/M-CARE	Domestic Service – California Alternate Rates
Small General Service	TOU-GS-1	Time-of-Use – General Service (< 20 kW)
Medium General Service	TOU-GS-2	Time-of-Use – General Service – Demand Metered (20 – 200 kW)
Large General Service	TOU-GS-3	Time-of-Use – General Service – Demand Metered (200 – 500 kW)
Industrial/Large Power	TOU-8-PRI	Time-of-Use – General Service – Large – Primary Transmission
	TOU-8-SEC	Time-of-Use – General Service – Large – Secondary Transmission
	TOU-8-SUB	Time-of-Use – General Service – Large - Subtransmission
Small/Medium Agricultural and Pumping	TOU-PA-2	Time-of-Use – Agricultural & Pumping – Small to Medium
Large Agricultural and Pumping	TOU-PA-3	Time-of-Use – Agricultural & Pumping – Large
Street Lighting	LS-1	Street and Highway Lighting – Unmetered Service – Company-Owned
Traffic Control	TC-1	Traffic Control Service

Based on this data, there are 1,497,747 SCE electric customers within the County served by SCE. Annual energy consumption for all of these customers was 26,290 GWh. Bundled customers (full service) make up over 99 percent of total customer accounts and comprise approximately 86 percent of the total energy use. Direct access customers account for only 0.7 percent of customers, but use nearly 16 percent of the annual energy. Exhibit 6 summarizes historic energy consumption and customer accounts for SCE customers within the County.

Exhibit 6
Summary of Load Data by Customer Type

Customer Category	Customer Accounts	Customer Accounts (% of total)	Annual Energy Use (MWh)	Energy Use (% of total)
SCE - Bundled Customers	1,497,747	99.3%	26,290,996	85.5%
Direct Access Customers	10,588	0.7%	4,465,290	14.5%
Total	**1,508,335**	**100.0%**	**30,756,286**	**100.0%**

Direct access customers purchase their power supply and other services from an electric service provider (ESP), rather than the incumbent utility. In California, eligibility for DA enrollment is currently limited to retail non-residential customers and enrollment is based on an annual lottery.[2] Customers classified as taking service under direct access arrangements were not included in this Plan, as it is assumed that these customers will remain with their current ESPs. Exhibit 7 shows consumption and customer counts by rate class for SCE's bundled customers in the County.

Exhibit 7
Summary of Bundled Load Data by Rate Class

Rate Class	Customer Accounts	Customer Accounts (% of total)	Annual Energy Use (MWh)	Energy Use (% of total)
Residential	1,242,505	83%	7,721,755	29.0%
Small General Service	200,197	13%	2,368,901	9.0%
Medium General Service	35,591	2%	5,344,593	20.0%
Large General Service	2,630	0.2%	2,656,395	10.0%
Industrial/Large Power	1,112	0.1%	7,372,587	28.0%
Small/Medium Agricultural and Pumping	2,098	0.1%	289,617	1.1%
Large Agricultural and Pumping	226	0.02%	215,097	0.8%
Street Lighting	8,195	0.5%	300,571	1.1%
Traffic Control	5,193	0.3%	21,290	0.1%
Total	**1,497,747**	**100.0%**	**26,290,996**	**100.0%**

Customers located in CCA-eligible Cities within the County account for approximately 80 percent of SCE customers and 85 percent of annual energy usage in all of the County. Potential customers and energy consumption by location are shown in Exhibit 8.

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

Exhibit 8 Summary of Bundled Load Data by Location				
Location within LA County	**Customer Accounts**	**Customer Accounts (% of total)**	**Annual Energy Use (MWh)**	**Energy Use (% of total)**
Cities	1,190,816	80%	22,448,984	85%
Unincorporated	306,930	20%	3,841,822	15%
Total County	**1,497,747**	**100%**	**26,290,996**	**100%**

In addition to the SCE consumption data, SCE provided annual consumption, annual revenue and annual peak demands for County-owned buildings served by SCE. Exhibit 8 summarizes the energy consumption and customer counts for County facilities located in the Cities and unincorporated areas of the County. This data provides the basis for Phase 1 of LACCE's Implementation Plan. Exhibit 9 shows that there are 3,358 total eligible County facilities in the County and these customers use approximately 472,892 MWh of energy per year. The number of County accounts are distributed nearly equally between Cities and unincorporated County areas, yet County buildings in Cities account for over two thirds of annual County electrical consumption.

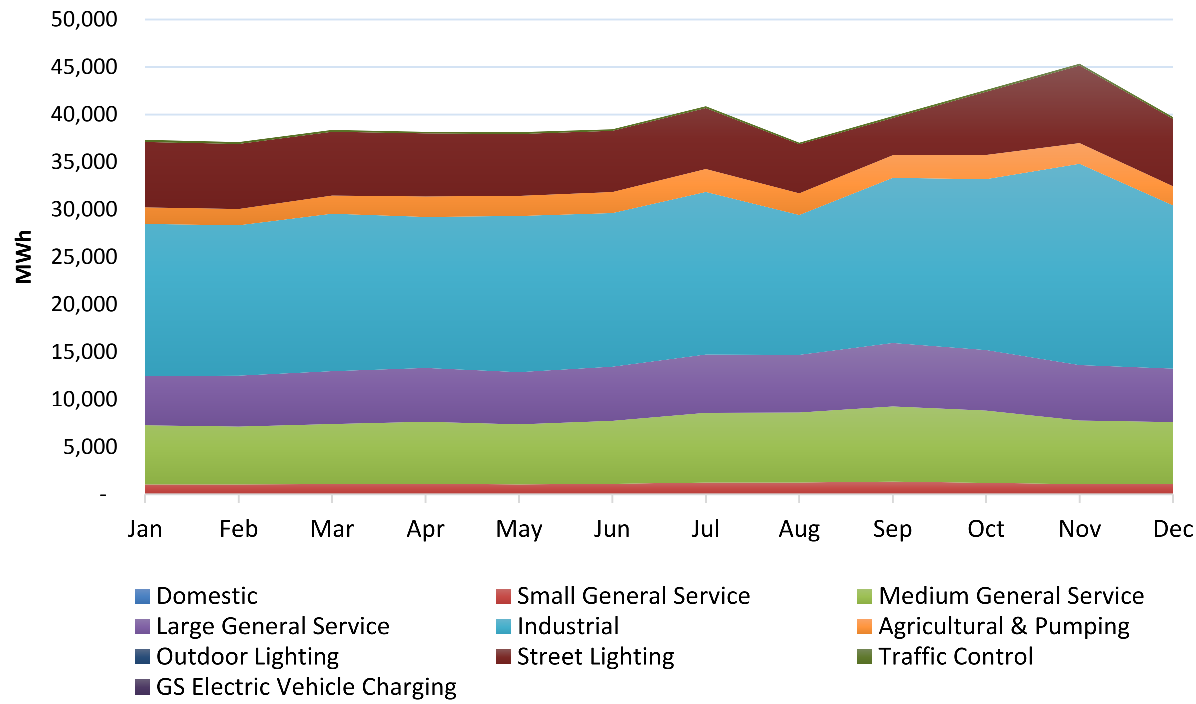
Exhibit 9 Summary of LA County Facility Load Data by Location				
Location	**Customer Accounts**	**Customer Accounts (% of total)**	**Annual Energy Use (MWh)**	**Energy Use (% of total)**
Cities	1,630	49%	298,027	63%
Unincorporated	1,728	51%	174,865	37%
Total	**3,358**	**100%**	**472,892**	**100%**

Exhibit 10 shows energy consumption and customer distribution by rate class for all County-owned facilities. General service customers account for over half of the County customers (55 percent) and 35 percent of County loads.

Exhibit 10 Summary of LA County Facility Load Data by Rate Schedule				
Rate Class	**Customer Accounts**	**Customer Accounts (% of total)**	**Annual Energy Use (MWh)**	**Energy Use (% of total)**
Domestic	71	2%	359	< 1%
Small General Service	1,361	41%	13,428	3%
Medium General Service	432	13%	81,666	17%
Large General Service	63	2%	69,606	15%
Industrial	30	1%	202,514	43%
Agricultural & Pumping	202	< 1%	25,650	5%
Outdoor Lighting	11	< 1%	20	< 1%
Street Lighting	340	10%	77,358	16%
Traffic Control	847	25%	2,290	< 1%
General Service Electric Vehicle Charging	1	< 1%	0.2	< 1%
Total	**3,358**	**100%**	**472,892**	**100%**

Since the County facilities data included annual totals only, assumptions were made to estimate monthly energy and monthly peak demands. Load profiles have been created, based on monthly loads for each rate schedule, from SCE-provided data. Load profiles were assigned to County facilities based on rate schedule. The resulting monthly energy distribution is illustrated in Exhibit 11. Monthly energy and customer estimates, by rate class and facility location, were used to adjust SCE data to avoid double-counting customers and energy when developing load forecasts.

Exhibit 11
Monthly Energy Use by Rate Class for Total County Facilities



Forecast Consumption and Customers

Upon enrollment of customers in each of LACCE's implementation phases, customers will be switched over to service with LACCE on their next regularly scheduled meter read date. Forecast loads are needed to estimate LACCE revenue and power supply costs. A range of load forecasts have been developed at the rate class level for each phase of LACCE's operations.

Average energy use per customer for residential and general service customers has been normalized to remove any abnormal weather impacts from the historic energy data. Going forward, projections for customers enrolled in LACCE and retail energy consumption have been forecast to increase at 1.5 percent per year. This forecast is based on the mid-case electricity demand forecasts for the SCE planning area, as reported to the California Energy Commission (CEC).[3] Hourly electric

[3] Southern California Edison. *California Energy Demand 2015 Revised - Mid Demand Case.* December 2015. Sacramento, CA: California Energy Commission.

consumption and peak demands have been estimated based on SCE's hourly load profiles for each customer classification.

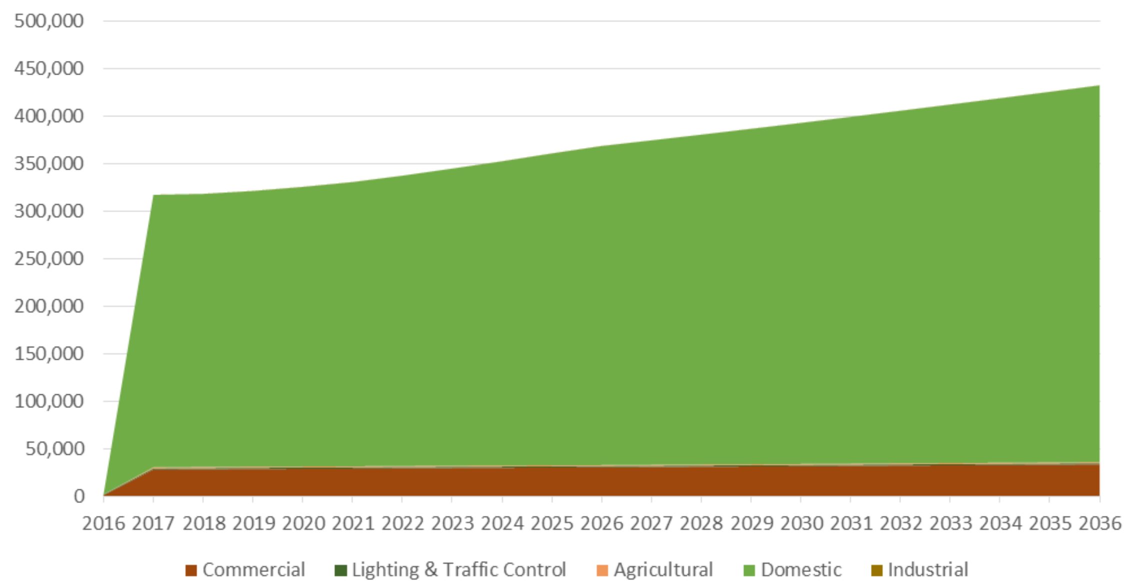
The number of accounts served by LACCE at the beginning of each phase is shown in Exhibit 12.

Exhibit 12
Projected Customer Enrollments

Program Customers	Phase 1	Phase 2
Domestic	43	286,656
Commercial	925	27,902
Industrial	10	135
Street Lighting & Traffic	686	1,288
Ag & Pump	64	986
Total	**1,728**	**306,903**

The forecast of service accounts (customers) served by LACCE for each of the next ten years is shown in Exhibit 13, which reflects an estimated annual growth of 1.5 percent and excludes other Cities.

Exhibit 13
Projected Service Accounts



The LACCE forecast of kWh sales reflects the roll-out and customer enrollment schedule shown above. The annual electricity needed to serve LACCE retail customers increases from just over 50 GWh in the first year to over 3,134 GWh by 2025. Annual energy requirements are shown below in Exhibit 14.

Exhibit 14 Projected Annual Energy Requirements									
	2017	2018	2019	2020	2021	2022	2023	2024	2025
Retail Sales (MWh)	1,646,785	2,873,075	2,894,927	2,921,864	2,952,194	2,995,937	3,040,110	3,085,547	3,134,997
Losses (MWh)	105,353	198,565	200,173	202,091	204,226	207,276	210,312	213,442	216,846
Total Load Requirements (MWh)	1,752,137	3,071,640	3,095,099	3,123,954	3,156,421	3,203,213	3,250,422	3,298,989	3,351,843

Renewable Resource Requirement

In addition to estimating the potential retail loads and customers, current legislation requires that a certain percent of annual retail electric sales be supplied from qualified renewable energy resources.

SBX1-2 passed in April, 2011 established a 33 percent Renewable Portfolio Standard (RPS) requirement by 2020 with certain procurement targets prior to 2020. SBX1-2 also defined three types of renewable categories (or Buckets) that can be used to meet the RPS target.

Bucket 1 – Renewable resources located in California or out-of-state renewable resources that can meet strict scheduling requirement ensuring deliverability into California. According to SBX1 2 there are no limits on Bucket 1 renewable resources.

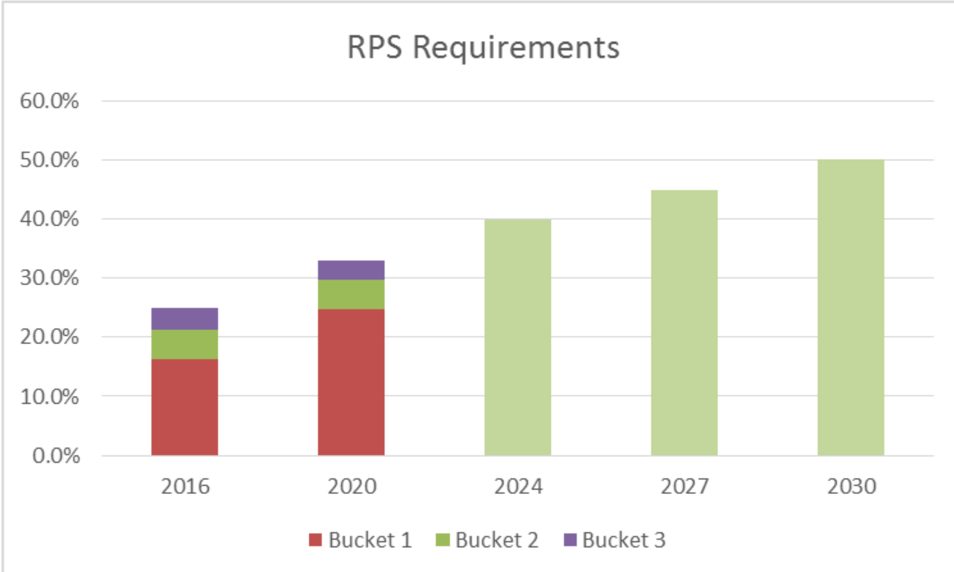
Bucket 2 – Bucket 2 renewable resources are firmed or shaped renewable resources not necessarily delivered to California, but an equivalent amount of energy is delivered from a different non-renewable resource and then bundled with Renewable Energy Certificates (RECs). Bucket 2 resources are limited to annual maximum of 20 percent of total RPS procurement through 2016 and 15 percent through 2020.

Bucket 3 – Bucket 3 consists of unbundled Renewable Energy Certificates (RECs) which are separated from the actual electric energy. Bucket 3 resources are limited to an annual maximum of 15 percent of total RPS procurement through 2016 and 10 percent through 2020.

In addition, SB350 increased the RPS requirement to 50 percent by 2030. At this time, the amount of REC's that can be used to meet the 50 percent RPS requirement has not been finalized.

Exhibit 15 provides an overview of the RPS requirements until 2030.

Exhibit 15
California RPS Requirements as a Percent of Total Power Supply



LACCE's Plan has been developed assuming LACCE will meet a 50 percent RPS target as soon as possible through contracts, distributed generation and local resources.

LACCE will exceed SCE's renewable energy percentage from the first day of its operations when it meets its 50 percent goal. LACCE will therefore significantly exceed the minimum RPS requirements and significantly exceed the renewable power share provided by SCE.

Resource Adequacy Requirements

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

The CPUC's resource adequacy standards applicable to LACCE require a demonstration one year in advance that LACCE has secured physical capacity for 90 percent of its projected peak demand for each of the five months May through September, plus a minimum 15 percent reserve margin. On a month-ahead basis, LACCE must demonstrate 100 percent of the peak load plus a minimum 15 percent reserve margin.

The Plan's load forecast estimates capacity needs, including resource capacity requirements, to be used for the power supply cost forecasting.

Power Supply Strategy and Costs

This section of the Plan provides a discussion of the power supply resource cost forecasts, potential power supply strategies that could be implemented by LACCE and provides portfolio pricing based on the loads projected for LACCE.

LACCE will be charged with developing both short (one and two-year) and long-term (five to twenty years) resource plans. LACCE will develop the resource plan under the guidance provided by the Joint Power Agency (JPA), in compliance with California law, and other requirements of California regulatory bodies (CPUC and CEC).

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

Resource Strategy

LACCE should seek to maximize the use of local, cost-effective renewable generation resources in its resource plan. The ability to invest capital in power supply and demand-side resources using tax-exempt financing is an important factor in LACCE's ability to increase the use of renewable energy while offering rates that are competitive with SCE. Power purchases from renewable and non-renewable resources will supply the remaining majority of the resource mix. LACCE's electric portfolio will be managed by a third party electric supplier, at least during the initial implementation period. Through a power services agreement, LACCE will obtain full service requirements electricity for its customers, including providing for all electric, ancillary services and the scheduling arrangements necessary to provide delivered electricity.

Resource Costs

For this Plan, individual resource costs are estimated and other energy providers based on current market condition, recent power supply contracts for renewable energy as well as a review of the applicable regulatory requirements.

Market Purchases

Natural gas-fired power plants are typically the marginal power supply resource that sets the electricity market price in southern California and elsewhere in the Western Energy Coordinating Council (WECC) footprint. WECC guides power supply resources west of the Rocky Mountains. As the market price of electricity is usually set by the cost of the marginal unit, a wholesale market price forecast has been developed using a forecast of natural gas prices and the projected relationship between gas price and electricity price (also defined as market-implied heat rates or spark spreads). The projected market-implied heat rates reflect the average efficiency of gas-fired power plants in California. Projected heat rates are based on historic market-implied heat rates which are calculated by dividing historic southern California (SP15) wholesale market prices by historic southern California natural gas prices. A natural gas price forecast has been developed based on NYMEX forward gas prices for the Henry Hub trading hub and southern California basis differentials. Projected market heat rates have then been applied to the southern California natural gas price forecast to calculate a wholesale electric market price forecast for southern California.

The following steps have been taken to produce the wholesale electric market price forecast:

1. Forward prices for natural gas at Henry Hub are available through June 2025. A 3.5 percent annual growth rate is assumed after June 2025.
2. The southern California basis differential is used to adjust the Henry Hub forward prices to southern California prices. Southern California forward natural gas prices are equal to NYMEX forward prices (Henry Hub) plus the southern California basis. The southern California basis forward curve is available through December 2020. After December 2020, the monthly southern California basis is assumed to increase at 4 percent.
3. Projected monthly market-implied heat rates are multiplied by forecast southern California natural gas prices to calculate forecast southern California wholesale market prices.
4. Projected heat rates are based on historic heat rates (southern California wholesale electricity prices divided by SoCal natural gas prices).
5. Monthly market-implied heat rates are held constant in all years.
6. Forecast southern California prices are benchmarked against other market price forecasts.

Based on the methodology detailed above, southern California wholesale market prices are projected to escalate annually at an average rate of 3.9 percent over 2017 through 2036.

Exhibit 16 shows the forecast southern California natural gas prices.

Exhibit 16
Forecast SoCal Natural Gas Price ($/MMBtu)

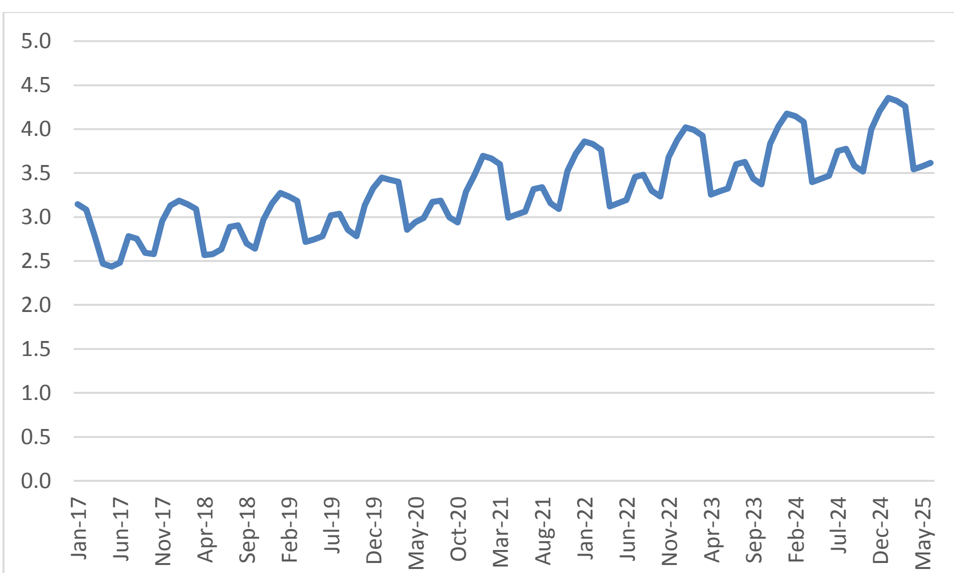
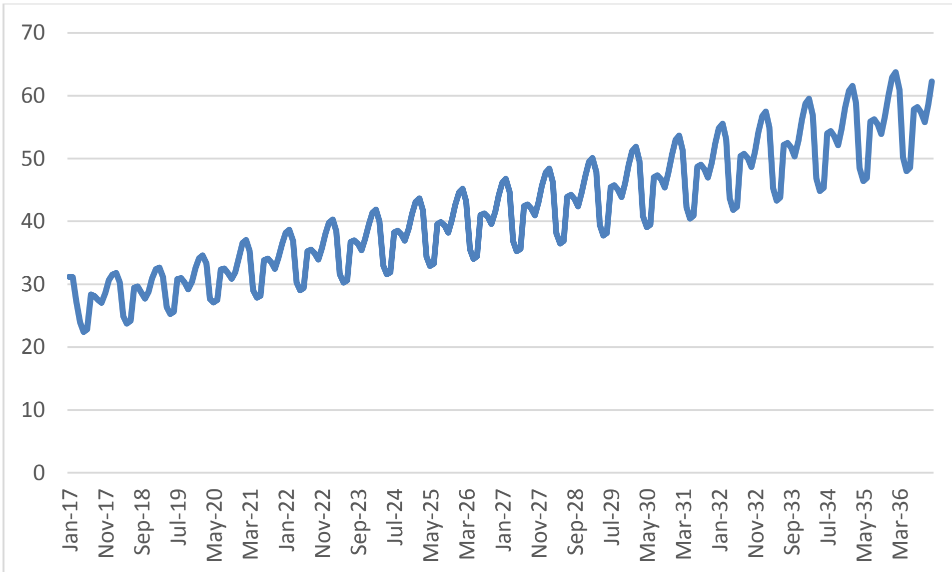


Exhibit 17 shows the resulting monthly southern California wholesale electric market price forecast. The levelized value of market prices over the study period is $39.5/MWh (2016 $) assuming a 4 percent discount rate.

Exhibit 17
Forecast Southern California Wholesale Market Prices ($/MWh)



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

Renewable Energy

The wholesale market prices shown above are for "brown" power (i.e., this product does not come with any renewable energy credit (REC) attributes). The costs of renewable resources vary greatly. Wind and solar levelized project costs vary from $35 to $60/MWh. Geothermal project costs can vary from $70 to $100/MWh. The availability of off-shore wind and ocean power in the marketplace is fairly minimal and, as such, these resources were not included in the assessment of renewable energy market prices.

Based on a survey of renewable resources currently in operation and new projects coming on-line, a base case renewable energy market price of $42/MWh has been determined. Renewable energy prices may increase in the future as the demand for renewable energy increases due to California's RPS. However, renewable prices are being driven down by solar project costs which have declined sharply over the past few years and are expected to continue to decrease over the next 10 to 20 years. Again, the renewable energy prices have been independently confirmed by current market tenders in southern California.

Projected power costs in this Plan are calculated using the base case renewable energy market price of $42/MWh. The amount of renewable energy purchased will be assumed to be equal to the RPS requirements in the base case. A higher case of 50 and 100 percent renewable energy will also be considered later in this Plan. In the "100 percent renewables" case the renewable energy market price was increased to $52/MWh. The $42/MWh price was based on an assumption that renewable purchases would be served almost exclusively with the output from solar projects. In the "100 percent renewables" case a higher price was assumed in recognition that a more diverse, and therefore more expensive, renewable energy portfolio would be needed. As such, the $52/MWh is a blend of projected solar, geothermal and wind project costs. This is a conservative assumption as 100 percent solar power procurement is likely an achievable objective for LACCE.

Renewable Energy Credits (RECs)

As noted earlier, California load serving entities must purchase renewable energy or attributes that meet certain eligibility requirements across three categories or buckets. Each of the buckets represents a different type of renewable energy and can be used to meet a specific percent of the total. The shares of each bucket also changes over time. The three buckets and the type of energy included in each bucket can be summarized as follows:

- Bucket 1: In-state renewable generation
- Bucket 2: Firmed and shaped renewable energy products from a generator that has its first point of interconnection with a California Balancing Authority (such as the CAISO)
- Bucket 3: Energy is not included with the RECs (also known as unbundled RECs)

Under the current guidelines, the amount of RECs procured through Buckets 1 and 2 is limited and decreases over time. Historically, the first bucket has been the most expensive type of energy to purchase and load serving entities were only procuring the minimum they need to meet the RPS requirement. However, with the decrease in solar project costs, Bucket 1 has become relatively less expensive (compared to Buckets 2 and 3).

RECs are not viewed as good for the development of new projects. In addition, the REC market is not as liquid as it once was. For the Plan's base case, unbundled REC prices are assumed to increase from $10/REC in 2017 to $20 in 2036 (3.7 percent annual escalation). Due to the decline in solar project costs (to near $40/MWh), the cost of unbundled RECs to meet RPS requirements and wholesale market purchases to meet load are negligible. Due to this shift in market dynamics, Bucket 3 RECs are no longer the least expensive option (as they were historically).

The Plan assumes that LACCE will not rely on REC purchases to meet RPS requirements. The REC market can, however, be used to balance RPS requirements with renewable energy acquisitions. If LACCE is short of RECs in a given compliance year, RECs could be purchased to meet the requirements. If the CCE is long on RECs in a given compliance year, surplus RECs could be sold.

Transmission

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

The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services. LACCE's Grid Management Charges are expected to near $0.5/MWh.

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

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

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

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

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

Based on a survey of ancillary service costs currently paid by CAISO participants, LACCE's ancillary service costs are estimated to be near $5/MWh. The Plan's base case will assume the CCE's ancillary service costs are $5/MWh in 2017, escalating by 1.5 percent annually thereafter. Serving a greater percentage of load with renewables will likely result in increased grid congestion and higher ancillary service costs. For this reason, the ancillary service costs have been increased in the 50 percent and 100 percent renewables cases included in this Plan. For the 50 percent renewables case, ancillary service costs are assumed to be $5.5/MWh in 2017, escalating by 1.5 percent. For the 100 percent renewables case, ancillary service costs are assumed to be $8/MWh in 2017, escalating by 2.5 percent.

Power Management/Scheduling Agent

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

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

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

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

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

- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO.

LACCE should approve and adopt a set of protocols that will serve as the risk management tools for LACCE and any third party involved in LACCE portfolio operations. Protocols will define risk management policies and procedures, and a process for ensuring compliance throughout the organization. During the initial start-up period, the chosen full requirements electric suppliers will bear the majority of risks and be responsible for their management. Development of protocols can take place during the first few months of LACCE operations to cover electricity procurement activities.

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

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

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

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

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

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

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

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

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

Based on conversations with scheduling agents currently working the CAISO footprint, the estimated cost of scheduling services is in the $1 to $2/MWh range. For the base case, the Plan has assumed a cost of $1.5/MWh or $2.4 million in 2017 after Phase 2 is operational and escalating at 2.5 percent annually.

Resource Portfolios

In order to develop pricing options for LACCE customers and evaluate the impact of varying levels of renewable resources in LACCE's portfolios, three resource portfolios were developed: RPS Portfolio, 50 percent renewable portfolio and 100 percent renewable portfolio.

Resource Options

For each of the resource portfolios, a combination of resources has been assumed in order to meet the renewable target, resource adequacy targets, and ancillary and balancing requirements.

Exhibit 18 shows the 20-year levelized resource costs included in this Plan.

Exhibit 18
20-Year Levelized Cost
(2016 $/MWH)

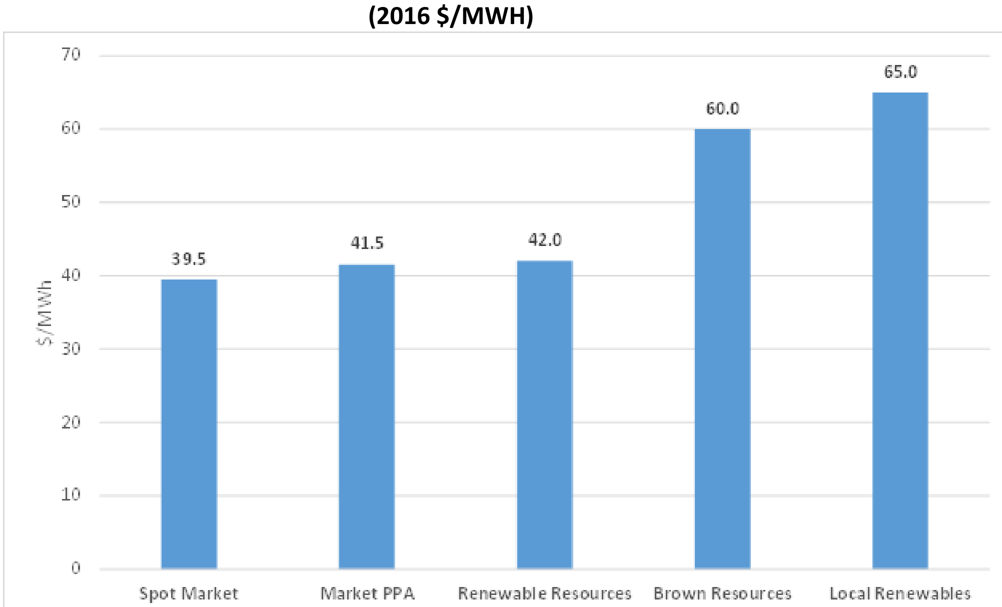


Exhibit 18 above includes both spot market and market PPA costs. It is assumed that these costs are primarily for natural gas resources although the specific resource source cannot be determined from a spot market purchase. Market PPA costs are slightly greater than spot market costs in recognition of the cost of the PPA supplier absorbing the market price risk associated with providing a long-term PPA contract price.

The capacity factor for market PPA purchases is assumed to be 100 percent (flat monthly blocks of power). The capacity factor for renewable resources and local renewables is assumed to be 33 percent. The capacity factor for non-renewable resources is assumed to be 80 percent. As noted above, the cost of renewable resources was increased from $42/MWh to $52/MWh in the 100 percent renewables case in recognition of the need for a more diverse mix of renewable resources. Again, this higher price may be mitigated if large solar projects continue to be pursued in California.

As shown above, the base case 20-year levelized cost of renewable resources is comparable to the 20-year levelized cost of market purchases. The cost of solar projects has declined significantly over the past few years. The $42/MWh projection is based on the cost of relatively new solar projects that reflect the decreased costs, on a $/watt basis, of solar projects and the extension of the Federal production tax credit. The $/watt is expected to continue to decrease in future years. As such, the cost of the output of solar projects is expected to continue to decrease.

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

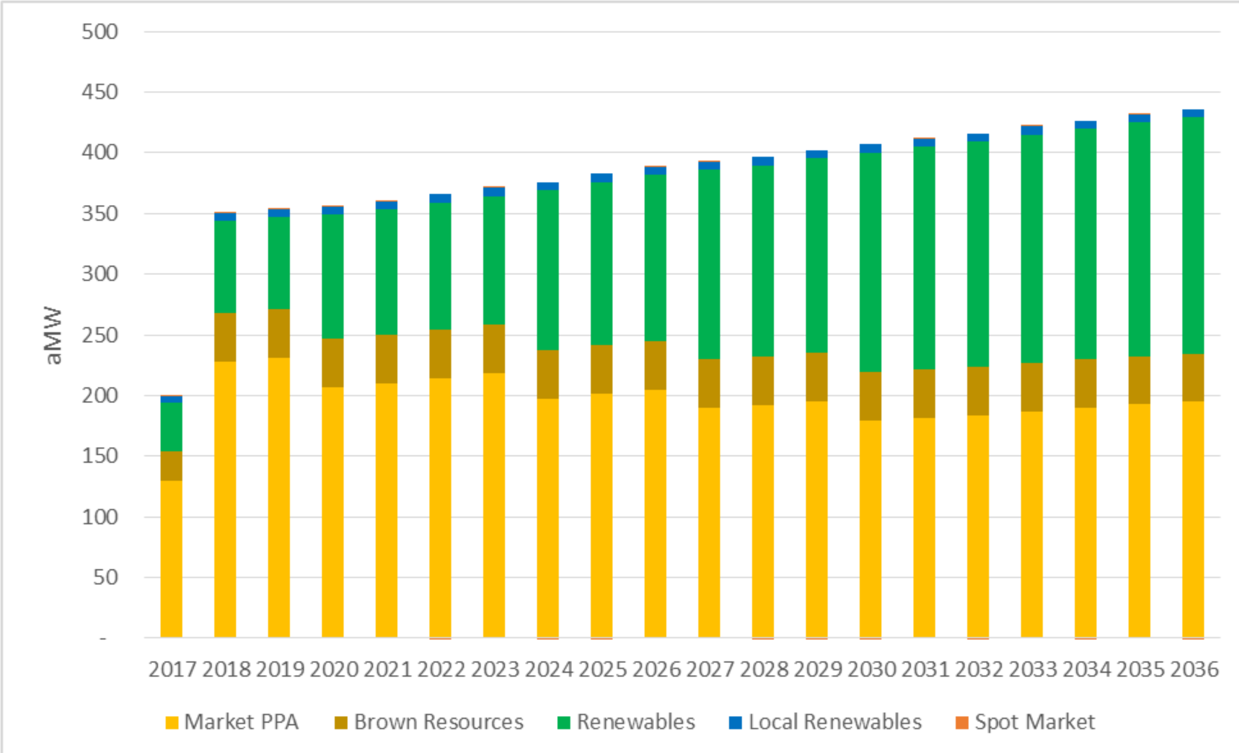
Portfolio 1: Meet Current RPS Requirements (Baseline Portfolio, similar to current SCE resource mix)

In the first portfolio, LACCE will meet the State RPS requirements shown below:

- 2017-19: 25 percent
- 2020-23: 33 percent
- 2024-26: 40 percent
- 2027-29: 45 percent
- 2030 - 50 percent

As shown above, due to the decrease in the cost of solar projects, the projected cost of renewables is only slightly greater than the cost of market power and less than the cost of greenfield brown resources (e.g. natural gas fired generation). Exhibit 19 shows the power supply portfolio used to serve load in Portfolio 1.

Exhibit 19
Portfolio 1: Meet RPS Requirements

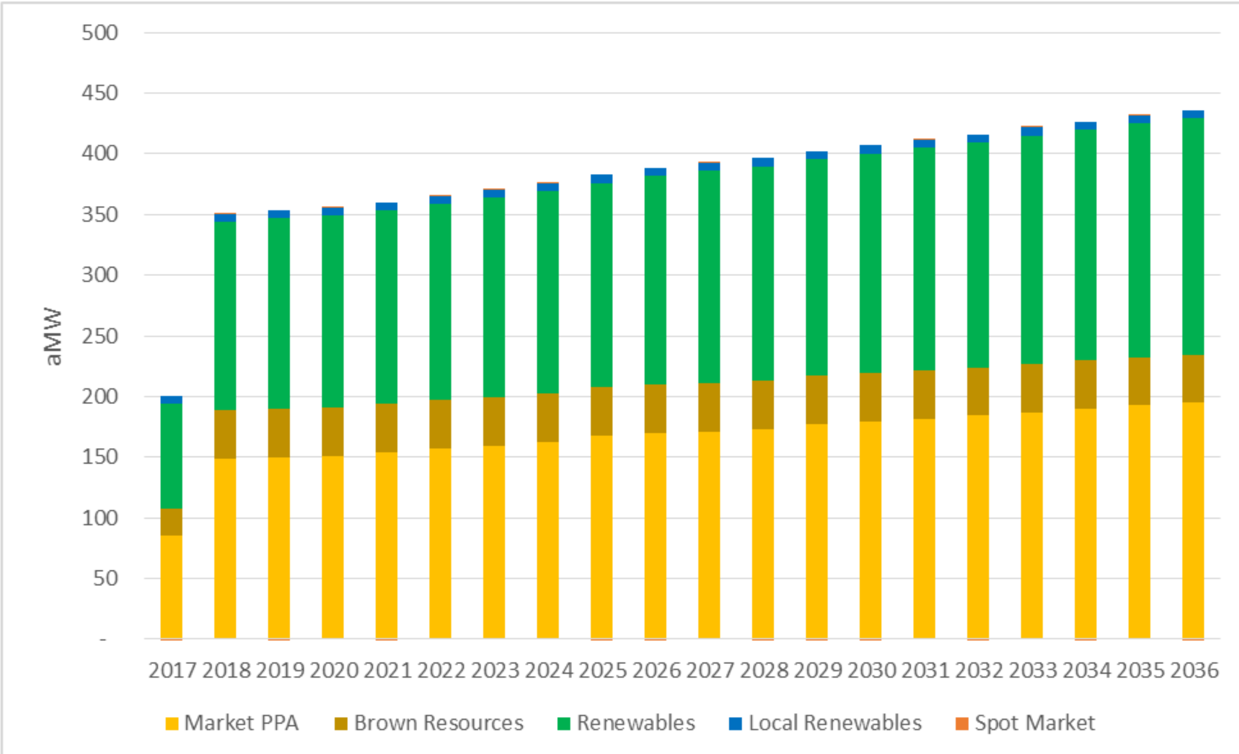


The green bars increase each year along with California's RPS requirements. The costs associated with this portfolio could be reduced if it was assumed that more power was purchased from market PPAs instead of brown resources. The percent of non-renewable energy purchased via market PPAs, as opposed to brown resources, is the same in each of the three portfolios.

Portfolio 2: Serve 50% of Retail Load with Renewables Starting on Day 1

In this portfolio, the 50 percent renewable energy purchase requirement in the RPS is effectively moved up from 2030 to January 1, 2017. The amount of power purchased from the relatively expensive ($65/MWh 20-year levelized cost) local renewables is held constant at 20 MW with a 33 percent capacity factor in each of the three portfolios. As shown below in Exhibit 20 the green bars showing renewable energy purchases in 2017 through 2029 increased compared to those shown above in Exhibit 19.

Exhibit 20
Portfolio 2: Serve 50% of Retail Load with Renewables

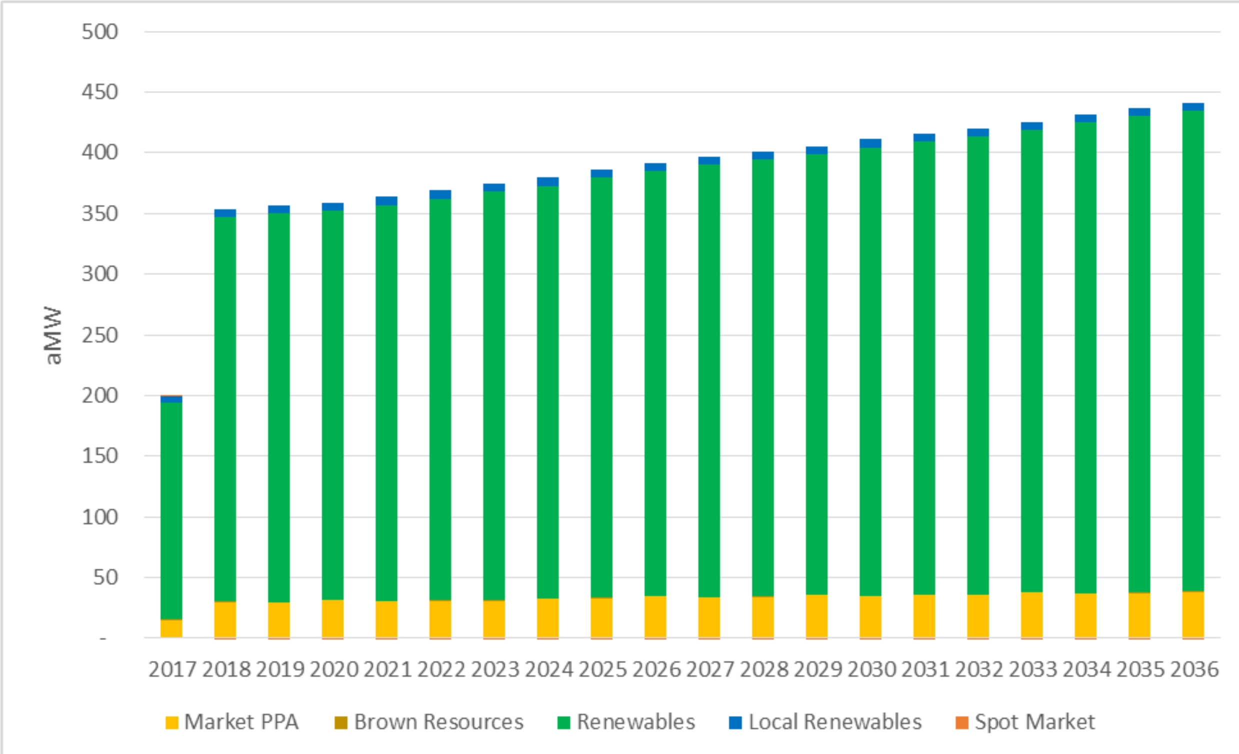


The percentage of non-renewable energy purchased from the more expensive brown resources is approximately the same as Portfolio 1. In all three portfolios, approximately 15 percent of non-renewable energy is purchased from brown resources, which has a base case 20-year levelized cost of $60/MWh. In all three portfolios, 85 percent of non-renewable energy is purchased at the lower $41.5/MWh levelized cost associated with market PPA purchases.

Portfolio 3: Serve 100% of Retail Load with Renewables Starting on Day 1

In this portfolio retail loads are served entirely with renewable energy purchases. It is also assumed that 50 MW of local renewable energy projects will be pursued in Phase 3. Exhibit 21 below shows the resource mix used to serve load in Portfolio 3.

Exhibit 21
Portfolio 3: Serve 100% of Retail Load with Renewables



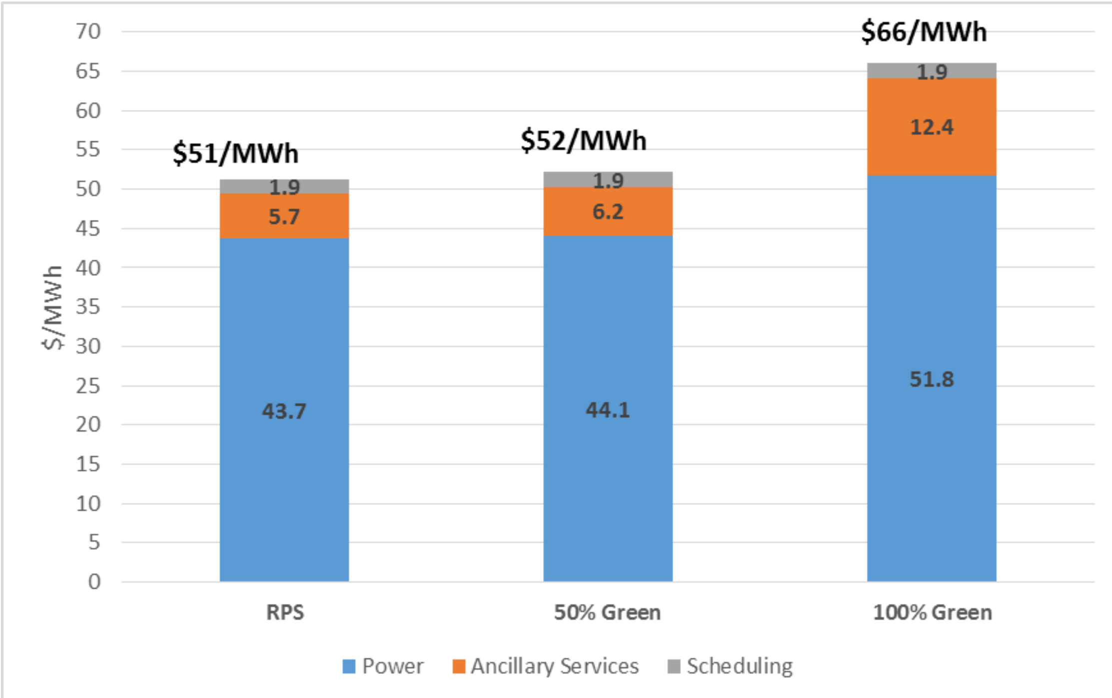
There is a small amount of market PPA and brown resource power included in Portfolio 3 due to distribution and transmission system losses and balancing requirements. The renewable energy requirements in the State's RPS are based on retail energy sales. To be consistent, it was assumed that the 100 percent renewable energy target would only apply to retail energy sales. The same concept applies to Portfolios 1 and 2. For example, renewable energy purchases in Portfolio 2 are equal to 50 percent of projected retail energy sales in all years.

Non-renewable resources will be needed in Portfolio 3 to serve load during hours when renewable resources are not capable of generating power (e.g. when the wind is not blowing or the sun is not shining). Purchasing an amount of renewable generation that is equal to 100 percent of LACCE's retail load will likely result in over-supply in on-peak hours when solar projects are generating power and under-supply in off-peak hours when solar projects are not generating. As such, on-peak energy may need to be exchanged for off-peak energy. The cost of exchanging or firming some of the solar generation into off-peak blocks of energy is reflected in higher ancillary service costs in Portfolio 3.

20-Year Levelized Portfolio Costs

The 20-year levelized costs have been calculated based on the base case assumptions detailed above regarding resource costs and resource compositions under the three portfolios. Exhibit 22 shows a breakdown of power, ancillary service and scheduling costs associated with each portfolio.

Exhibit 22
20-year Levelized Base Case Portfolio Costs ($/MWh)



As shown above in Portfolios 1 and 2, power costs are fairly similar across the three portfolios. There is not a large variance in power costs in these two portfolios because the majority of power is supplied by market PPA and renewable energy purchases in each portfolio. The projected costs of renewable energy and market PPA purchases are very close. Exhibit 18 shows that at $42/MWh the projected 20-year levelized cost of renewables is only $0.5/MWh greater than the projected 20-year levelized cost of market PPA purchases at $41.5/MWh.

Total costs under Portfolio 3 are approximately $15/MWh greater than Portfolios 1 and 2. The costs of renewables have been assumed to be $10/MWh greater in Portfolio 3 than in Portfolios 1 and 2 in recognition of the need for a more diverse mix of renewable resources. This translates into greater power costs (the blue bar) for Portfolio 3.

Each portfolio assumes that 15 percent of non-renewable energy is purchased from brown, natural gas-fired resources with a projected 20-year levelized cost of $66/MWh. However, since more non-renewable energy is purchased in Portfolio 1 it has the highest percentage of brown resource purchases. In Portfolio 1, 9 percent of power purchases are brown resource purchases, compared to 8 percent in Portfolio 2 and 1 percent in Portfolio 3.

LACCE Cost of Service

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

Cost of Service for LACCE Operations

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

- Power Supply Costs
- Non-Power Supply Costs
    - Start-up costs
    - LACCE staffing and administration costs
    - Consulting Support
    - SCE and regulatory charges
    - Financing costs
- Pass-Through Charges from SCE
    - Transmission and distribution charges
    - Power Cost Indifference Adjustment (PCIA) Charge
    - Other non-bypassable charges

Once the costs of LACCE operations have been determined, the total costs can be used to develop LACCE rates to be compared to SCE's projected rates.

Power Supply Costs

A key element of the cost of service analysis is the assumption that electricity will be procured under a power purchase arrangement (PPA) for both renewable and non-renewable power until local LACCE resources can be developed. Power supply must be obtained by LACCE's procurement contractor prior to commencing operations. The products required from the third party procurement are energy, capacity, renewable energy, load forecasting and scheduling coordination.

The calculated starting cost of electric power supply, including the cost of the scheduling coordinator and all regulatory power requirements, is between \$43 and \$62 per MWh. This price represents the price needed for a full requirements electricity contract. The variation in price is a function of the desired level of renewable resources.

Non-Power Supply Costs

While power supply costs make up the majority of costs associated with operating LACCE (roughly 80 percent), there are several additional cost components that must be considered in the pro forma financial analysis. These additional non-power supply costs are noted below. This calculation assumed LACCE non-power supply costs began accumulating in June of 2016.

Startup Activities and Costs

Monthly costs associated with LACCE start-up and phasing of customer enrollments include expenditures for program staff/contract staff, associated infrastructure, contractor costs and fees payable to SCE by LACCE. The estimated startup costs include capital expenditures and one-time expenses as well as ongoing expenses that will be accrued before significant revenues from LACCE operations are realized. These cost components are quantified in Exhibit 23 and Exhibit 24 below.

Exhibit 23
Monthly Start-Up Cost Summary

	Pre-Start						
	June	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
Start-Up Costs							
Infrastructure	$0	$0	$45,000	$35,000	$25,000	$25,000	$25,000
Consultants	$70,000	$100,000	$120,000	$120,000	$120,000	$130,000	$130,000
Staffing	$0	$0	$45,000	$55,000	$55,000	$55,000	$55,000
Utility Trans. Fee	$0	$0	$0	$780	$0	$0	$2,938
Total Start-Up	**$70,000**	**$100,000**	**$210,000**	**$210,780**	**$200,000**	**$210,000**	**$212,938**

Exhibit 24
Start-Up Costs Summarized by Phase

		Phase 1	Phase 2
	Total Pre-Start Costs	**2017**	**2018**
Start-Up Costs			
Infrastructure	$155,000	$160,000	$230,000
Consultants	$790,000	$715,000	$715,000
Staffing	$265,000	$380,000	$1,215,000
Utility Trans. Fee	$3,718	$1,132,892	$230,000
Total Start-Up	**$1,213,718**	**$2,387,892**	**$2,390,000**

Other costs related to starting up LACCE's program will be the responsibility of LACCE's contractors. These include capital requirements paid by others, customer information system costs, electronic data exchange system costs, call center costs, and billing administration/settlements systems costs. The costs payable by LACCE are contained in Exhibit 24.

Estimated Staffing Costs

Staffing is a key component of the start-up. Staff will be added incrementally to match workloads involved in forming LACCE, managing contracts, and initiating customer outreach/marketing during the pre-operations period.

Exhibit 25 provides the estimated staffing budgets for the startup period (Phase 1 and Phase 2 of LACCE implementation). Staffing budgets include direct salaries and benefits. For start-up, it is anticipated that LACCE will employ one assistant Executive Director and one manager of policy and regulatory affairs. The remaining functions will be performed by consultants. Exhibit 25 details the anticipated staffing of LACCE.

Exhibit 25
Staffing Plan

Number of Staff	Pre Start-Up	2017	2018
Executive Director	0	1	1
Assistant Executive Director	1	1	1
Legal, Policy & Regulatory Manager	1	1	1
Regulatory Analyst	0	1	1
Administrative Assistant	0	1	1
Finance & Rates Manager	0	1	1
Rates Analyst	0	1	1
Accounting & Billing Analyst	0	1	1
Human Resources Manager	0	1	1
HR Specialist	0	1	1
Sales & Marketing Manager	0	1	1
Energy Efficiency Program Manager	0	0	1
Account Representatives	0	0	1
Communication Specialists	0	0	1
IT Manager	0	1	1
IT Specialist	0	0	1
Total Number of Employees	2	12	17
Total Staffing Costs	$45,000*	$1,595,000	$3,396,600

*Represents only partial year.

Based on this staffing plan, LACCE will initially employ 2 staff members. Once LACCE has expanded its service area to the unincorporated County and operated for one year, it is anticipated that staffing will increase to approximately 17 employees. These positions to be hired by LACCE over the first two years are described below:

Executive Director

The Executive Director will be responsible for overseeing LACCE operation and ensuring that the vision of the JPA Board is followed. The Executive Director will ultimately be responsible for all LACCE programs, finances and communication programs plus be accountable to the Board.

Assistant Executive Director

The Assistant Executive Director will oversee the day to day operation of LACCE. In particular, this staff position will work closely with outside consultants, and oversee hedging and power procurement, resource portfolio strategy, CAISO settlements and other financial planning and rate setting analysis. Behind the meter LACCE programs will also be coordinated through this position.

Policy and Regulatory Manager

The Policy and Regulatory Manager will oversee the legal and regulatory functions of LACCE. This position will work closely with the CPUC and State/Federal legislators. LACCE will require ongoing regulatory representation to file resource plans, resource adequacy compliance, compliance with

California RPS, and overall representation on issues that will impact LACCE and its customers. LACCE will maintain an active role at the CPUC, CEC, FERC and the California legislature.

Finance and Rates Manager

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

Sales and Marketing Manager

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

Administrative Assistance

The staffing plan assumes a full-time administrative assistance will be added during the pilot phase to provide administrative assistance to management.

Future Staff

As additional customers join LACCE, duties can be shifted from third-party consultants to in-house staff if internal staffing is more cost effective.

Estimated Infrastructure Costs

Infrastructure or overhead needed to support the organization includes computers and other equipment, office furnishings, office space and utilities. These expenses are estimated at $155,000 during program pre-startup. Office space and utilities are ongoing monthly expenses that will begin to accrue before revenues from program operations commence and are therefore assumed to be financed as shown in Exhibit 26 and Exhibit 27.

Exhibit 26
Monthly Estimated Infrastructure Costs

	Pre-Start						
	June	July	Aug	Sept	Oct	Nov	Dec
Infrastructure Costs							
Computers	$0	$0	$10,000	$5,000	$0	$0	$0
Furnishings	$0	$0	$10,000	$5,000	$0	$0	$0
Office Space	$0	$0	$15,000	$15,000	$15,000	$15,000	$15,000
Utilities/Other Office Supplies	$0	$0	$10,000	$10,000	$10,000	$10,000	$10,000
Total Start-Up	**$0**	**$0**	**$45,000**	**$35,000**	**$25,000**	**$25,000**	**$25,000**

Exhibit 27 Estimated Infrastructure Cost by Phase			
		Phase 1	Phase 2
	Total Pre-Start Costs	2017	2018
Infrastructure Costs			
Computers	$15,000	$5,000	$40,000
Furnishings	$15,000	$5,000	$40,000
Office Space	$75,000	$90,000	$90,000
Utilities/Other Office Supplies	$50,000	$60,000	$60,000
Total Infrastructure Costs	**$155,000**	**$160,000**	**$230,000**

It is estimated that the per employee start-up cost is approximately $10,000. This expense covers computer and furniture needs. An additional annual expense of $180,000 for office space, and approximately $120,000 per year in office supplies and utilities costs is expected.

Utility Implementation and Transaction Charges

The estimated costs payable to SCE for services related to LACCE start-up include costs associated with initiating service with SCE, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees. These distribution utilities fees are explicitly stated in the relevant SCE tariffs.

Customers who establish service with LACCE will be automatically enrolled in the program and have sixty days from the date of enrollment to customer opt-out of the program. Such customers will be provided with two opt-out notices within this sixty-day post enrollment period. The first notice will be mailed to customers approximately sixty days prior to the date of automatic enrollment. A second notice will be sent approximately thirty days later. As required by CPUC regulations, LACCE will use SCE's opt-out processing service. Following automatic enrollment, two additional opt-out notices will be provided within the sixty-day period following customer enrollment. It is estimated that the charges for the opt-out notices will be approximately $10,000 for 2016 and $3.1 million for 2017, as shown in Exhibit 28 and Exhibit 29.

Exhibit 28 Monthly Utility Transaction Fees							
	Pre-Start						
	June	July	Aug	Sept	Oct	Nov	Dec
Enrollment Charges	$0	$0	$780	$0	$0	$2,938	$6,203
Ongoing Charges	$0	$0	$0	$0	$0	$0	$0
Total SCE Transaction Fee	**$0**	**$0**	**$780**	**$0**	**$0**	**$2,938**	**$6,203**

Exhibit 29 Utility Transaction Fees by Phase			
		Phase 1	Phase 2
	Total Pre-Start Costs	2017	2018
Enrollment Charges	$9,921	$1,128,588	$1,212,268
Ongoing Charges	0	4,305	779,791
Total SCE Transaction Fees	**$9,921**	**$1,132,892**	**$1,992,059**

Estimates of Third Party Consultant Costs

Contractor costs include outside assistance for advertising, legal services, resource and financial planning, implementation support, customer enrollment, customer service, and payment processing/accounts receivable and verification. The latter three will be provided by LACCE's customer account services provider, and these preliminary estimates will be refined as the services and costs provided by the selected contractor are negotiated. Exhibit 30 and Exhibit 31 show the estimated contractor costs during the startup period.

Exhibit 30
Monthly Estimated Consultant Costs

	Pre-Start						
	June	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
Legal/Regulatory	$20,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
Communication	$0	$0	$0	$0	$0	$10,000	$10,000
Data Management	$0	$0	$20,000	$20,000	$20,000	$20,000	$20,000
Financial Consulting	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
Total Consultant Costs	**$70,000**	**$100,000**	**$120,000**	**$120,000**	**$120,000**	**$130,000**	**$130,000**

Exhibit 31
Estimated Consultant Costs by Phase

		Phase 1	Phase 2
	Total Pre-Start Costs	**2017**	**2018**
Legal/Regulatory	$320,000	$250,000	$250,000
Communication	$20,000	$200,000	$200,000
Data Management	$100,000	$12,960	$2,377,248
Financial Consulting	$350,000	$265,000	$265,000
Total Consultant Costs	**$790,000**	**$727,960**	**$3,092,248**

The estimate for each of the services is based on costs experienced by other CCEs.

Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that will be required until full operation of LACCE is achieved. For the purposes of this analysis, it is assumed that LACCE pre-operations begin in June 2016 and continue through the end of 2016. In general, the components of the cash flow analysis can be summarized into two distinct categories: (1) Cost of LACCE operations, and (2) Revenues from LACCE operations. The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with LACCE and specifically account for the transition or "Phase-In" of LACCE customers. The cash flow analysis assumes the phase-In schedule for LACCE as described previously.

The cash flow analysis also provides estimates for revenues generated from LACCE operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes the customer phase-in schedule noted above, and assumes that LACCE provides a discount of 4.0 percent from the existing rates for each customer class, where pre-operations run from June 1, 2016 to December 31, 2016. Thereafter, Phase 1 starts in January 2017 and Phase 2 starts in July 2017.

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

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

A summary of working capital needs is presented below on Exhibit 32.

Exhibit 32
Working Capital Needs

	2016	2017
Working Capital	$6,500,000	$42,000,000

Total Financing Requirements

The start-up of the LACCE program will require a significant amount of capital for three major functions: (1) staffing and contractor costs; (2) program initiation; and (3) working capital. Each of these anticipated requirements is discussed below.

Staffing costs for the pre-implementation period (June 2016 through December 2016) are estimated to be approximately $265,000. Contractor costs for the same time period are estimated to be approximately $790,000. These costs include: advertising/communications, consulting, legal, and data management.

LACCE initiation costs include the infrastructure that LACCE will require (office space, utilities, computers) as well as the distribution utility fees for initiating LACCE. Infrastructure costs are estimated to be approximately $155,000 and the distribution utility fees are estimated to be approximately $1,140,000.

The Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to SCE service under certain circumstances. In addition, SCE requires a bond equivalent to two months of transaction fees.

During the start-up and pilot periods, the total financing requirements are estimated to be approximately $10 million, increasing to approximately $40 million following enrollment of unincorporated County customers. The first $10 million is needed in early summer of 2016.

Financing Plan

The initial start-up funding will be provided via short-term financing. LACCE will recover the principal and interest costs associated with the start-up funding via subsequent retail rates. It is anticipated that the start-up costs will be fully recovered within the first two years of LACCE operations.

The anticipated start-up and working capital requirements for LACCE through Phase 1 are approximately $10 million. Once the LACCE program is up and running, these costs would be recovered through retail rates. Actual recovery of these costs will be dependent on third-party electricity purchase prices and decisions regarding initial rates for Phase 1 customers.

Additional financing will be needed at the beginning of Phase 2. Depending on market conditions and payment terms established with the third-party suppliers, the loan may need to be increased to approximately $42 million for the start of Phase 2. This number will be refined as the LACCE program becomes operational, and bids are received from power providers.

Appendix B contains a preliminary discussion from Public Financial Management, Inc. (PFM) on the options available to LACCE for funding the first two phases of LACCE operations. Based on this information, the Plan's financial analysis assumes that LACCE can obtain a loan for the first $10 million with a term of 2 years at a rate of 5.5 percent. The second loan for $42 million is assumed for a 20-year term at 5.5 percent.

Products, Services, Rates Comparison and Environmental/Economic Impacts

This section of the Plan provides a comparison of service and rates between SCE and LACCE. Rates are evaluated based on total LACCE electric total bundled rates as compared to SCE's total bundled rates. Total bundled electric rates include the rates charged by LACCE, including non-bypassable charges, plus SCE's delivery charges. This section also includes the environmental impacts based on the reduction in Green House Gases (GHG), and the economic development impact on local jobs and overall economic activity created by LACCE programs.

Rates Paid by SCE Bundled Customers

The average customer weighted SCE rates have been calculated based on current rate schedules and LACCE's projected customer mix. SCE's current 2016 rates and surcharges have been applied to customer load data aggregated by major rate schedules to form the basis for the SCE rate forecast.

The average SCE delivery rate, which is paid by both SCE bundled customers and LACCE bundled customers, has been calculated based on the forecasted customer mix for LACCE. For future years, the SCE rate forecast assumes the delivery costs will increase by 2 percent per year, a conservative assumption given the history of SCE rate increases.

Similarly, the current average power supply rate component for SCE bundled customers has been calculated based on the estimated LACCE customer mix. The SCE power supply rate component has been forecast to increase based on SCE's most recent filings and incorporating the increased RPS requirement mandated by SB 350. In the 2015/2016 Energy Resource Recovery Account (ERRA) filing, SCE reduced overall power supply rates due to lower than anticipated fuel and purchase power, over collection in balancing accounts, and adjustment of GHG costs and allowance revenues. Some of these adjustments are one time only and of short duration while others are due to the current energy market in California. For 2017, SCE rates have been normalized to remove the one-time impact of over collection of balancing accounts and other onetime adjustments. Finally, the SCE power supply rates have been projected to increase based on the renewable and non-renewable market price forecast, regulatory requirement for RPS, storage requirement(s) and resource adequacy objectives.

Rates Paid by LACCE Customers

It is anticipated that LACCE's rate designs will initially mirror the structure of SCE's rates so that similar rates can be provided to LACCE's customers. In determining the level of LACCE rates, the financial analysis assumes the customer phase-in schedule noted above and that the implementation phase costs are financed via a start-up loan.

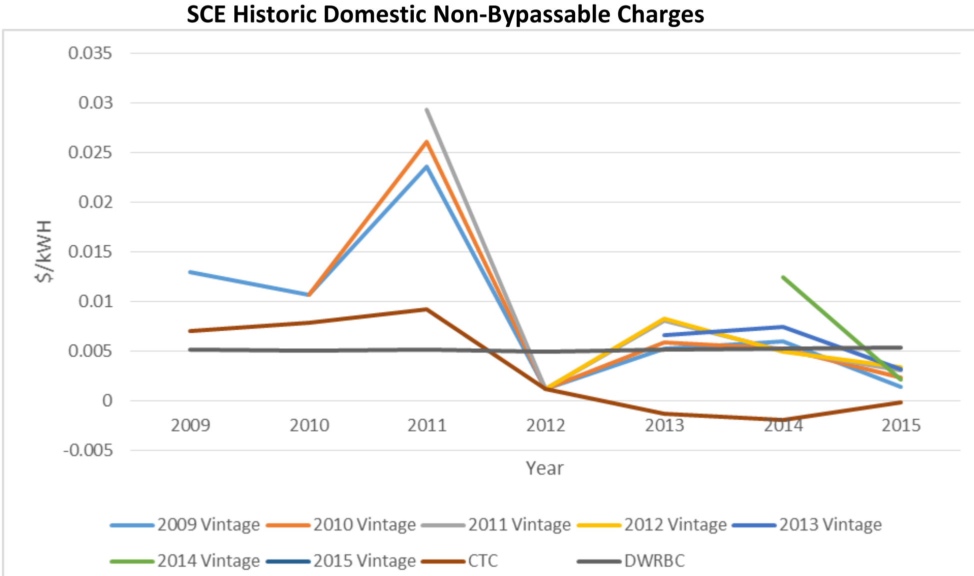
In addition to paying LACCE's power supply rate, LACCE customers will pay the SCE delivery rate and several non-bypassable charges. The calculation of the delivery rate is described earlier. The non-bypassable charges that are payable to SCE by LACCE customers include:

- Power Cost Indifference Adjustment (PCIA)
- Department of Water Resources Bond Charge (DWRBC)
- Competition Transition Charge (CTC)
- Generation Municipal Surcharge (or Franchise Charge)

The DWRBC is the charge to recover the interest and principle of the California Department of Water and Resources (DWR) bonds. The CTC is the ongoing charge which recovers the above market costs of utility generation. The PCIA is a charge that is designed to keep bundled customers indifferent when other customers leave bundled service. The PCIA is calculated annually by subtracting the market price of wholesale power from the incumbent utility's average cost of power supply based on a methodology determined by the CPUC.[4]

Exhibit 33 provides the historic values of the PCIA, CTC and DWRBC for the residential customer class (domestic schedule). It is important to note that the non-bypassable charges differ by the vintage of a CCA. The vintage of the CCA depends on when the CCA provides a binding notice of intent to SCE.

Exhibit 33
SCE Historic Domestic Non-Bypassable Charges



Note that CARE and medical base line customers do not pay the DWRBC or PCIA charges.

For this Plan, it is assumed in the base case that the PCIA charges are based on the differential between SCE's generation cost and market prices. If the difference between SCE's power costs and

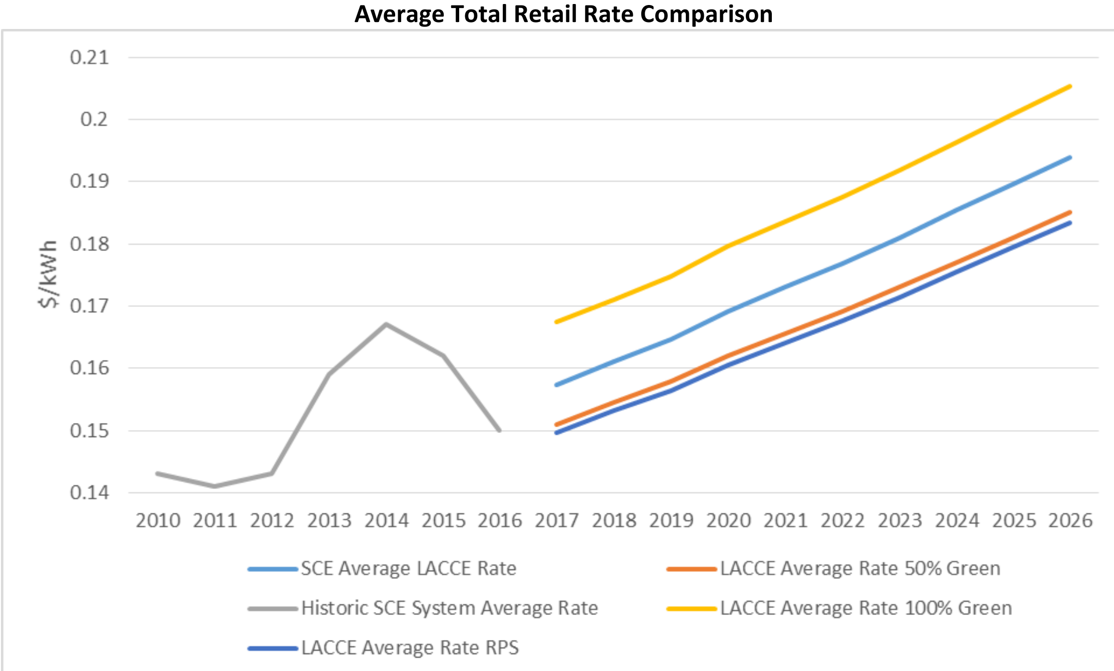
[4] See D.-6-07-030 as modified by D. 11-12-018.

market prices declines, then the PCIA will decline. The PCIA increases if the difference between market price and SCE generation costs increases. For this Plan, the PCIA is forecast to increase initially due to the end of offsetting credits that expire in 2018. Post-2018, the PCIA is expected to grow based on the inverse of the market price growth rate. As market prices increase, SCE's surplus resources become more cost effective and the PCIA therefore decreases.

Rate Impacts

Based on LACCE's projected power supply costs/operating costs and SCE's power supply/delivery costs, forecasts of LACCE and SCE total rates have been developed. These rates are illustrated below on Exhibit 34.

Exhibit 34
Average Total Retail Rate Comparison



As can be seen above, LACCE RPS residential rate with an equal amount of renewable power (28 percent) to what SCE currently offers is .9¢/kWh or 5.4 percent lower than SCE's 2017 rates. LACCE residential rate with 50 percent renewable power (compared to SCE's 28 percent) is .7¢/kWh or 4.1 percent lower than SCE's rates for roughly twice the amount of green renewable power. LACCE residential rate with 100 percent green power (compared to SCE's 28 percent) is 1.1¢/kWh or 6.3 percent higher, but this additional amount comes with almost four times more renewable power than the comparable SCE rate. These rate calculations assume all bill savings associated with forming LACCE will be refunded to the residences and businesses within the County. Based upon final LACCE policy direction, some of these savings could be retained by LACCE to build up financial reserves and/or build more local renewable energy projects.

As an alternative to its standard rates with 28 percent renewable power, SCE also offers rates which feature 50 percent and 100 percent renewable power. For the residential customers, SCE estimates energy costs to be 3.5 cents per kWh higher for each kWh served on the green rate. The LACCE rates for 50 percent and 100 percent renewable power for residential customers are therefore estimated at 12-13 percent lower.

Based on these assumed LACCE discounts off the comparable SCE rate, Exhibit 35 provides a comparison of the indicative bundled rates for LACCE's products compared to the current SCE rate.

Exhibit 35
Indicative Rate Comparison ($/kWh)

Rate Class	SCE Bundled Rate*	LACCE RPS Bundled Rate	LACCE 50% Green Bundled Rate	LACCE 100% Green Bundled Rate
Residential	17.1	16.2	16.4	18.2
GS-1	16.6	15.7	15.9	17.7
GS-2	15.8	15.0	15.2	16.9
GS-3	14.5	13.8	13.9	15.5
PA-2	12.6	12.0	12.1	13.4
PA-3	10.4	9.9	10.0	11.1
TOU-8 Secondary	13.1	12.4	12.6	14.0
TOU-8 Primary	11.7	11.1	11.2	12.5
TOU-8 Substation	7.5	7.1	7.2	8.0
Total LACCE Rate Savings (Increases)		5.4%	4.1%	(6.3%)

*SCE bundled average rate based on Table 3 in Advice 3319-E-A.

A financial proforma in support of these rates can be referenced in Appendix C.

Local Resources/Behind the Meter LACCE Programs

LACCE should plan to establish a Net Energy Metering ("NEM") program for qualified customers in their service territory to encourage Distributed Energy Resources (DER). In addition, LACCE will work with State agencies and SCE to promote deployment of DER within LACCE's service territory, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public goods surcharges.

LACCE should also establish a program which offers a combination of retail tariffs, rebates, incentives and other bundled offerings intended to increase customer participation in demand-side programs including: renewable distributed generation, energy storage, energy efficiency, demand response, electric vehicle charging, and other clean energy benefits defined as Distributed Energy Resources (DER). LACCE will work with State agencies and SCE to promote deployment of DERs in specific and targeted locations throughout SCE's distribution grid in order to help support efficient grid operations and maintenance as part of development of the future "smart grid.".

Additionally, LACCE will pursue energy efficiency programs at a faster pace than SCE. Below are ongoing activities undertaken by the SoCalREN under two current proceedings at the CPUC which are leading to a transformation of the energy industry.

Under the CPUC's current Energy Efficiency Proceeding (R. 13-11-005), the SoCalREN has already been established as an independent administrator of energy efficiency funding provided from Southern California Edison and Southern California Gas Company ratepayers. The current proceeding seeks to establish energy efficiency programs under a "Rolling Portfolio" funding cycle which could provide stable, predictable program funding for up to 10 years. The "Rolling Portfolio" concept will allow energy efficiency program administrators, like the SoCalREN, to conduct more strategic planning, development and implementation of programs.

Under the CPUC's current Distribution Resource Plans (R.14-08-013), and Distributed Energy Resources (R. 14-10-003) Proceedings, the SoCalREN is a proceeding participant seeking to help establish resource programs which are comprehensive (i.e., include all demand side management resources such as energy efficiency, storage, demand reduction, distributed generation) and which are compensated for multiple benefits that they produce (energy efficiency, real-time grid operations benefits, reduced grid operations and maintenance expenses, and greenhouse gas reductions). Each of these proceedings examine different aspects of creating, integrating and funding distributed energy resources.

CCEs, as entities that can provide wholesale power and design retail rates without lengthy and expensive regulatory proceedings, and as entities that can design and implement other end-user programs using wholesale power or other revenues, are uniquely positioned to be valued partners of investor-owned utilities who would retain their role as distribution grid operators. CCEs program and rate flexibilities can perfectly complement utilities efforts to maximize grid operations and flexibility in a world where behind the meter (and ahead of the meter) distributed generation, energy storage, thermal storage, electric vehicle charging, demand reduction and energy efficiency will increase dramatically. CCEs can partner with utility grid operators in aggregating and financing locational-specific distributed resources in grid areas of specific needs as well in assisting IOUs in investing in these distributed resources.

The SoCalREN is already funded and operational, and is an active participant in these new proceedings. This is advantageous in that any new CCE would typically have to apply for energy efficiency or other CPUC funding under regulated proceedings.

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

The amount of renewable power in SCE's power supply portfolio is 28 percent[5] and will rise to 33 percent by 2020. LACCE is committed to reductions in greenhouse gas emissions. Based on the power supply strategy described previously, GHG emission reductions resulting from the formation of LACCE are estimated to range from 289,080 to 505,890 tons CO_2e per year by 2019 assuming a 50 percent RPS target is achieved. The baseline for comparison is the projected resource mix used by SCE in the same time period. Exhibit 36 details these reductions.

[5] http://www.cpuc.ca.gov/RPS_Homepage/

Exhibit 36 Baseline Comparison of GHG Reduction by LACCE			
	2017	**2018**	**2019**
Forecast Renewables (50% Renewables) LACCE (MWH) – Phase 2	1,438,275	1,459,854	1,459,854
LACCE RPS (MWH) – Phase 2	730,029	737,154	737,154
Additional Green Power	708,246	722,700	722,700
CO2 reduction – Low (Metric Tons of CO_2e)	283,298	289,080	289,080
CO2 reduction – High (Metric tons of CO_2e)	495,772	505,890	505,890

These reductions in GHG emissions associated with LACCE operations are significant. Assuming only Phase 2 loads (all unincorporated County loads) are being met by LACCE, CO_2e emissions associated with in-County electricity use will be reduced by 1-2 percent. At full Phase 3 build-out, CO_2 emissions associated with in-County electricity use will be reduced roughly 12-25 percent by LACCE operations.

Economic Development

The analyses contained in this Plan of forming LACCE has focused only on the direct effects of this formation. However, in addition to direct effects, indirect microeconomic effects are also encountered.

The indirect effects of creating LACCE include the effects of increased commerce and improved environmental and health conditions. Within this Plan, an Input/Output (IO) analysis is undertaken to analyze these indirect effects. The IO model turns on the assumption that forming LACCE will lead to lower energy rates for their customers. Three types of impacts are analyzed in the IO model. These are described below.

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

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

Environmental and Health Impacts – With the creation of LACCE, other non-commerce indirect effects will occur. These may be largely environmental such as improved air quality or improved human health due to LACCE adopting mainly renewable energy sources versus continuing use of traditional energy sources. This resource strategy significantly reduces GHG emissions compared with SCE's current resource mix. While the change in GHG emissions is not modeled directly in economic development models used in this Plan, the reduction of these GHGs may be captured in indirect effects projected by the models.

Input-Output Modeling (IO modeling)

IO modeling is a quantitative analysis representing relationships (dependence) between industries in an economy. IO models are based on the implicit assumption that each basic sector has a multiplier, or ripple effect, on the wider economy because each sector purchases goods and services to support that sector. IO modeling estimates the inter-industry transactions and uses those transactions to estimate the economic impacts of any change to the economy.

The IO model used in the Plan, IMPLAN, displays the economic impacts of changes in rates into four categories: employment, labor income, value added, and output. Employment is the number of jobs gained or lost. Labor income involves the increase in salaries and wages for current and newly gained or lost employees. Value added, similar to Gross Domestic Product (GDP), is the payment to labor and capital used in production of a particular industry.

IO models are made up of matrices of multipliers between each industry present in an economy. Each column shows how an industry is dependent on other industries for both its inputs to production and outputs. The tables of multipliers can be used to estimate the effects in changes in spending for various industries, household consumption, or labor income. Both positive and negative impacts can be measured using IO modeling. IO modeling produces results broken down into several categories. Each of these is described below:

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

This study uses value added and employment figures to represent the total additional economic impact for each Project Alternative. IMPLAN has been used in this Plan to gauge the impacts on the County of retail rate reductions associated with forming LACCE. These impacts are discussed in detail below.

Increase in Disposal Income Associated with Rate Reduction Impacts

Exhibit 37 shows the effects $20 million in rate savings will have on the County's economy. The $20 million rate savings represents the minimum bill savings per year achievable by LACCE once Phase 3 operations begin. Direct effects from reduced rates are expected to add 98 jobs. Indirect effects are expected to add about 10 jobs. The induced effects of the project create approximately 211 jobs in the County with over $9.6 million in labor income. It is also projected that the total value added will be approximately $15.9 million and output close to $24.2 million. Exhibit 37 details the macroeconomics on the County of the anticipated LACCE customer bill reductions.

Exhibit 37 $20 Million Rate Savings Effects on County Economy				
Impact Type	**Employment**	**Labor Income**	**Total Value Added**	**Output**
Direct Effect	98.3	$3,674,939	$5,376,863	$7,099,612
Indirect Effect	10.4	$608,838	$1,057,593	$1,677,591
Induced Effect	102.1	$5,319,262	$9,472,599	$15,391,851
Total Effect	210.7	$9,603,040	$15,907,056	$24,169,054

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand. Again, these macroeconomic impacts shown on Exhibit 37 could be 6-7 times greater at Phase 3 build-out.

DER Development Impacts

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

Users input general information about a particular energy project, such as the project location, the type of system being installed, nameplate capacity, annual operations and maintenance costs, and others. JEDI has default but modifiable data regarding various aspects of each energy system type, such as equipment costs, tax parameters, and labor costs. JEDI then uses the input general information and the data, default or modified, to run calculations on the types of economic effects produced by the proposed project. This model can output projected direct job creation by industry, indirect job and business increases due to the project, projected operation costs, and more.

In order for JEDI to provide information, it must be populated with detailed data for the assumed DER project. Projected system data, type of solar cell, nameplate capacity (kW), and the number of systems. As an example of the macroeconomic activity caused by local DER deployment, this Plan assumes the installation of a 50 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. It is anticipated that LACCE will ultimately install a number of larger local solar projects such as the one described above. Exhibit 38 describes the macroeconomic impacts of constructing only one of these local solar projects.

Exhibit 38
Projected Solar Systems Impacts on County's Economy

Description	Jobs	Earnings, $000	Output (GDP), $000
During Construction and Installation Period			
*Project Development and Onsite Labor Impacts			
Construction and Installation Labor	342.5	$22,182	
Construction and Installation Related Services	374.3	$20,007	
Subtotal	716.8	$42,189	**$67,620**
*Module and Supply Chain Impacts			
Manufacturing Impacts	0.0	$0	**$0**
Trade (Wholesale and Retail)	79.4	$4,425	**$12,887**
Finance, Insurance and Real Estate	0.0	$0	**$0**
Professional Services	53.9	$2,326	**$6,908**
Other Services	141.4	$15,048	**$42,364**
Other Sectors	317.1	$10,656	**$19,428**
Subtotal	591.7	$32,455	**$81,587**
Induced Impacts	326.7	$13,067	**$39,092**
Total Impacts	1,635.3	$87,710	**$188,298**
During Operating Years			
*Onsite Labor Impacts			
PV Project Labor Only	9.2	$555	**$555**
*Local Revenue and Supply Chain Impacts	2.7	$145	**$458**
*Induced Impacts	1.9	$74	**$221**
Total Impacts	13.8	$774	**$1,235**

Exhibit 38 shows the construction and ongoing effects of building 50, 1 MW solar power systems. It is projected that roughly 1,635 jobs will be created during construction and installation. Of this total, about 719 jobs will be directly involved in construction and installation while roughly 592 jobs will be indirectly involved with the building of the project. Induced impacts of the construction and installation will create approximately 327 jobs. These induced effects may include anything from increased employment in restaurants, retail, education, and others. Overall, the building of this one solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. LACCE will need 2,000 – 3,000 MW of solar power plants at Phase 3 build-out so the potential employment impact on the County could be very significant.

The aforementioned economic analysis provides the base case analysis of forming LACCE. This base case is predicated on numerous assumptions and estimates that influence the overall results. This section of the Plan will provide the range of impacts that could result from changes in the most significant variables. In addition, this section will address risks that cannot be quantified, but should be addressed and mitigated to the maximum amount possible. Each key assumption is discussed, a band of uncertainty is established and LACCE's rate impacts associated with factoring in this uncertainty is developed for each key variable.

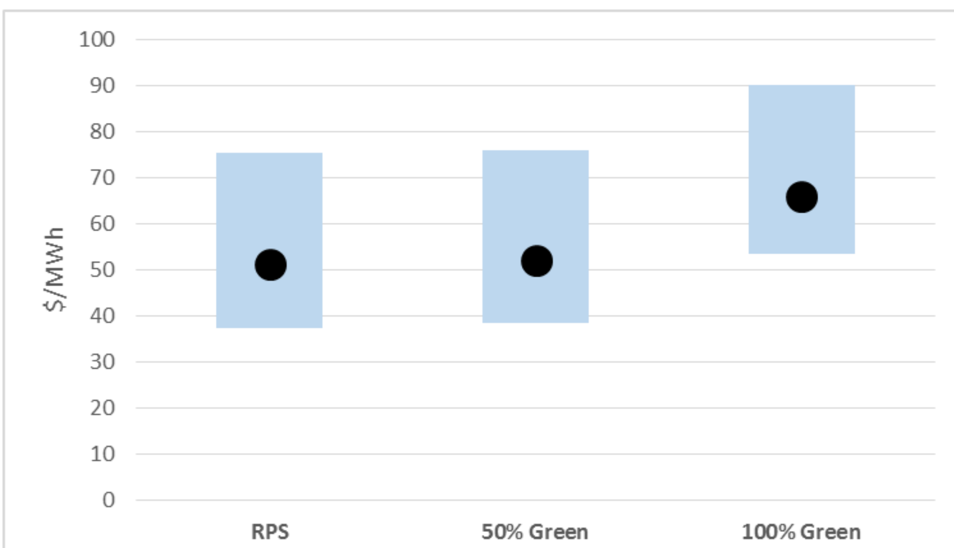
Since resource costs are based on forecast natural gas, wholesale market and renewable market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculation to fluctuations in these projections. Exhibit 39 below shows a summary of low, base, and high resource costs.

Exhibit 39
Low, Base and High 20-year Levelized Resource Costs ($/MWh)

Case	Market PPA	Portfolio 1 and 2 Renewables	Portfolio 3 Renewables	Brown Resources	Local Renewables
Low Case	25.0	32	40	45	45
Base Case	41.5	42	52	60	65
High Case	70.0	62	76	80	85

The 20-year levelized costs of each portfolio has been calculated using the range of resource costs shown above. The base case costs are depicted by the black dots in Exhibit 40.

Exhibit 40
Sensitivity of Portfolio 20-year Levelized Costs



Portfolio 3, which relies on renewable energy purchases to serve all retail loads, has the highest projected costs that range from a low of $54/MWh to a high of $90/MWh. The low case for Portfolio 3 ($54/MWh) is greater than the base case for both Portfolios 2 and 3. The likelihood of solar costs increasing to the point that 20-year levelized costs are near $62/MWh seems unlikely. All signs point to decreases in solar equipment costs on a $/watt basis. There have been significant decreases in solar costs over the past few years. Given the financial incentives targeted at the solar industry as well as the continuing advances in technology, it seems very unlikely that solar costs will increase over the next 10 to 20 years.

The potential for market PPA prices to increase to the high case of $70/MWh has a much higher likelihood. Wholesale market prices are dependent on many factors the most notable of which are natural gas prices. Natural gas prices are at historic lows and wholesale market prices have followed. However, natural gas prices are subject to variety of local, national and international forces that could drastically alter the current market place. For one, increased regulation of the natural gas industry with respect to the deployment of fracking technology could cause decreases in natural gas supplies and commensurate increases in natural gas prices. If natural gas prices increased, it is highly likely that electric wholesale market prices would also increase.

When evaluating risks, it is important to note that power supply costs are approximately 79 percent of the total CCE costs, SCE non-bypassable charges account for 13 percent and CCE operating costs account for 8 percent of total CCE revenue requirement.

Loads and Customer Participation Rates

The Plan bases the 20-year load forecasts on expected load growth, load profiles and participation rates. In order to evaluate the potential impact of varying loads, low, medium, and high load forecasts have been developed for the sensitivity analysis. SCE made available load shape profiles by customer class for the entire SCE service area. These load profiles were applied to all customer loads despite the varying climate zones within the County.

Another assumption that can impact the costs of LACCE are the customer participation rates. This Plan uses a conservative participation rate as the base case. A higher participation rate will increase energy sales relative to the base case and decrease the fixed costs paid by each customer. On the other hand, a reduced participation rate will increase the fixed costs to LACCE participants. Sensitivity to changes in projected loads has been tested for the high and low load forecast scenarios. For the sensitivity analysis, the high case assumes an additional 10 percent participation rate, while the low case assumes the participation rate is reduced by 50 percent. The low case assumes a 0 percent growth in energy and customers after 2017, while the high scenario assumes a 5 percent growth in energy and customers.

SCE Rates and Surcharges

The base case forecast of SCE rates assumes delivery rates increase at 2 percent per year and generation rates increase approximately 2.0 percent based on the projected market prices and renewable resource growth rates.

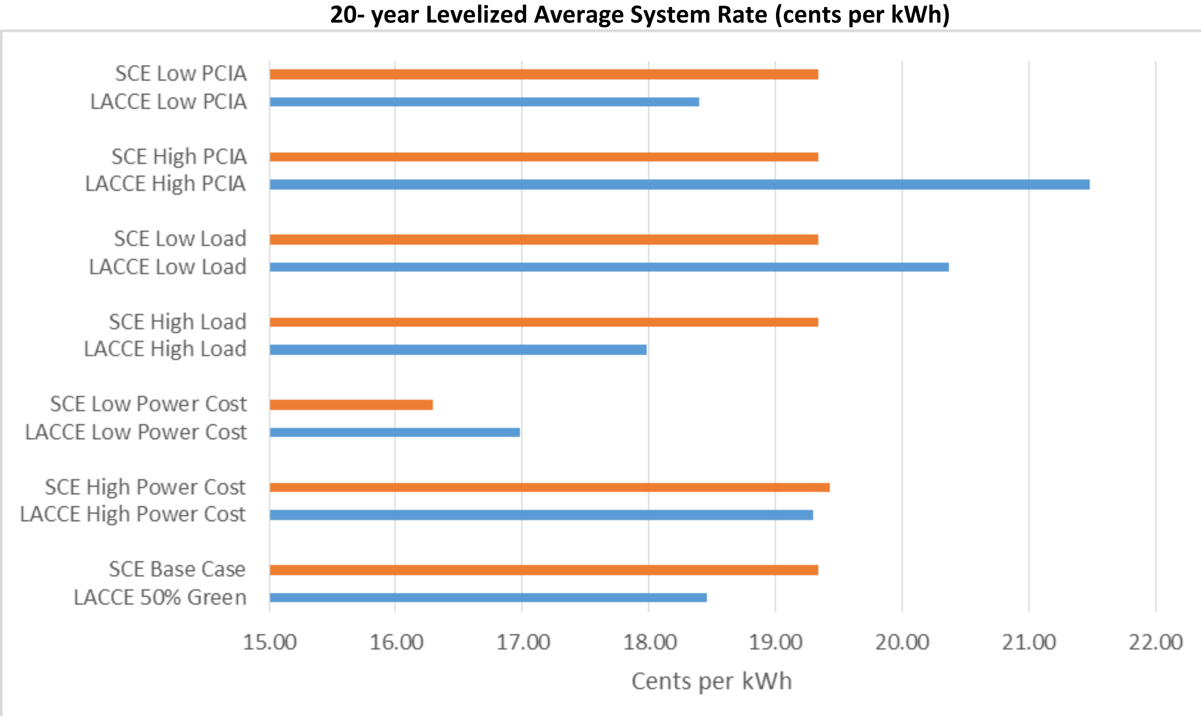
There are numerous factors that could impact SCE's rates in addition to the market price impacts described above. Regulatory changes, plant or technology retirements or additions, and the long-term impact of the Aliso Canyon leak all can impact SCE rates in the future. To address these uncertainties, sensitivity to the SCE results has been modeled assuming a high and low SCE generation growth rate of 5 percent and 1.5 percent respectively.

The level of the PCIA and the amount of franchise surcharges will impact the cost competiveness of LACCE. In order to be cost-effective, LACCE power supply costs plus PCIA and other surcharges must be lower than SCE's generation rates. Over time, the PCIA will vary, but it is expected that it will decline as market prices increase. The PCIA reflects SCE's own resources and signed contracts. Once the contracts expire, the related PCIA will disappear. Sensitivity to the PCIA has been modeled in the high case by assuming the PCIA would increase to reflect a historic high of 2.5 cents per kWh and remain flat for the 20-year analysis period. For the low case, it was assumed that the PCIA decreases by 50 percent in year 1 and remains flat for the 20-year analysis period.

Sensitivity Results

Exhibit 41 provides the results of the sensitivity analysis for the 50% Green Scenario, which is the most likely portfolio for LACCE to pursue. This sensitivity shows that the biggest risk to LACCE is if the PCIA increases to historic levels, LACCE does not achieve sufficient customer participation or if market prices fall significantly below their current historical low level.

Exhibit 41
50% Green Portfolio Sensitivity
20- year Levelized Average System Rate (cents per kWh)



This sensitivity analysis shows that LACCE rate could be greater than SCE rates if:

- The PCIA becomes larger by orders of magnitude
- LACCE loads are much less than forecast
- Wholesale market prices are much less than current experience

Each of these three scenarios has a low risk of actually occurring. For example, wholesale market prices for natural gas/electricity are at all-time lows. The probability of any significant further lowering of these prices is judged to be very small. The PCIA level should be fairly stable going forward as regulatory remedies are in play to stabilize the PCIA and the CCA vigilance in this area has increased markedly. Finally, a relatively high customer opt-out percentage in this Plan has been assumed when compared to those experienced by operating CCAs. It is very unlikely LACCE loads will not meet or exceed those assumed in this Plan.

Risks

Regulatory Risks

Regulatory issues continue to arise that may impact the competitiveness of LACCE. However, California's operating CCAs have worked hard to address any potentially detrimental changes through effective lobbying and technical support.

New legislation can also impact LACCE. For example, new legislation that recently affected CCAs are SB 350 and AB 1110. In addition, there are several changes that impact CCEs regarding power supply procurement and contracting. The CCE-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCEs must be aware, however, of the long term contracting requirement associated with renewable energy procurement.

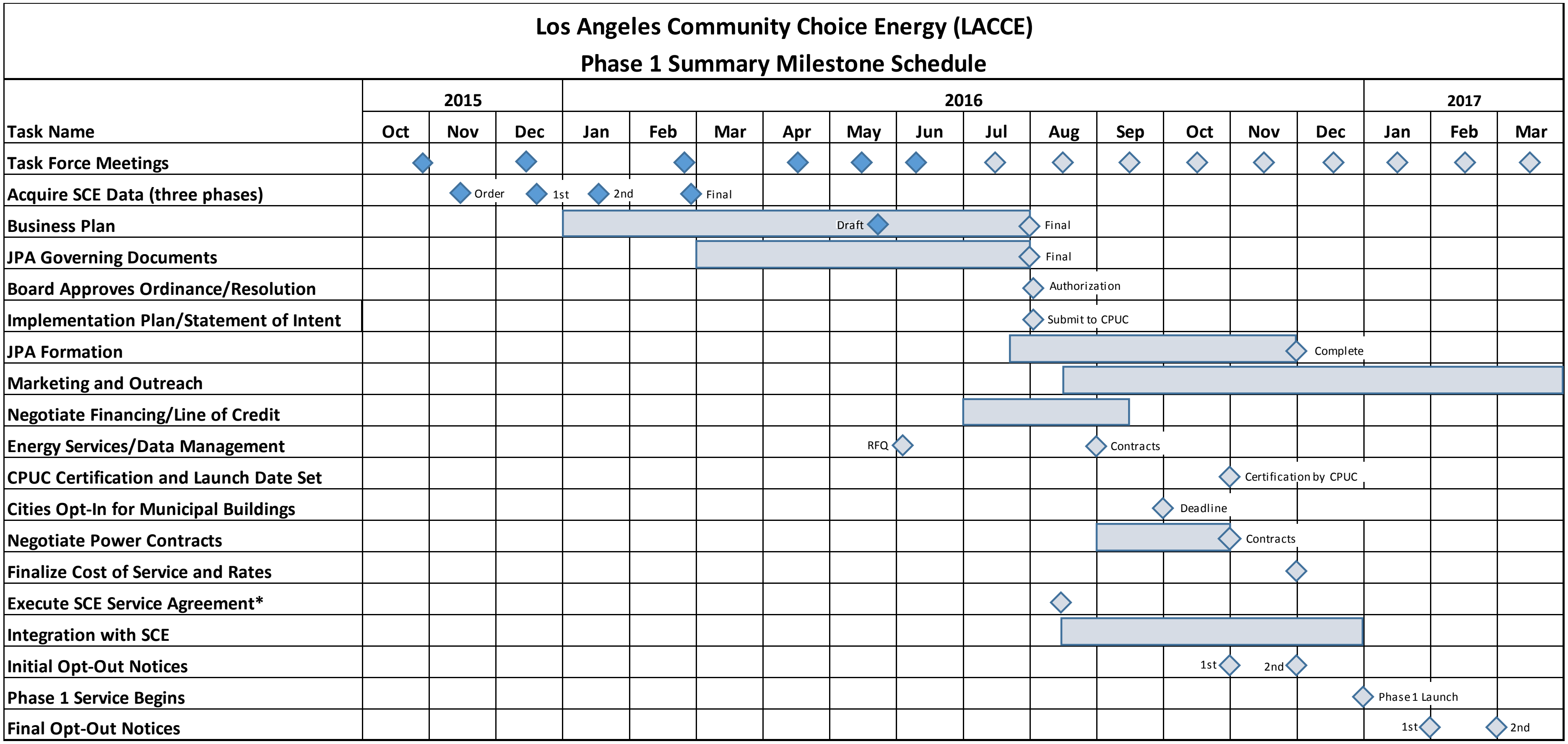
Regulatory risks also include the potential for utility generation costs to be shifted to non-bypassable and delivery charges. LACCE will need to continually monitor and lobby at the Federal, State and local levels to ensure fair and equitable treatment related to non-bypassable charges.

Participating Cities

LACCE has the possibility of being one of the largest utilities in California. As such, it is prudent to proceed with caution and implement LACCE's enrollment incrementally. The proposed phase-in approach allows for LACCE to hire staff and consultants incrementally, and ensure the power supply procurement, billing and data management process are smooth and with limited issues. This Plan demonstrates that if LACCE does not add any Cities to its service area, it is still cost competitive with SCE projected rates. As additional Cities are added, it is expected that LACCE rates will be reduced even more when compared to SCE's.

Schedule

A schedule for LACCE start-up is provided below.


Los Angeles Community Choice Energy (LACCE)
Phase 1 Summary Milestone Schedule
2015
2016
2017
Task Name
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Jan
Feb
Mar
Task Force Meetings
Acquire SCE Data (three phases)
Order
1st
2nd
Final
Business Plan
Draft
Final
JPA Governing Documents
Final
Board Approves Ordinance/Resolution
Authorization
Implementation Plan/Statement of Intent
Submit to CPUC
JPA Formation
Complete
Marketing and Outreach
Negotiate Financing/Line of Credit
Energy Services/Data Management
RFQ
Contracts
CPUC Certification and Launch Date Set
Certification by CPUC
Cities Opt-In for Municipal Buildings
Deadline
Negotiate Power Contracts
Contracts
Finalize Cost of Service and Rates
Execute SCE Service Agreement*
Integration with SCE
Initial Opt-Out Notices
1st
2nd
Phase 1 Service Begins
Phase 1 Launch
Final Opt-Out Notices
1st
2nd

Summary and Recommendations

Rate Impacts and Comparisons

The first impact associated with forming LACCE will be lower electricity bills for LACCE customers. LACCE customers should see no obvious changes in electric service other than the lower price and more renewable power procurement. Customers will pay the power supply charges set by LACCE and no longer pay the higher costs of SCE power supply.

Given this Plan's findings, LACCE's rate setting can establish a goal of providing rates that are lower than the equivalent rates offered by SCE even under the 50 percent renewable portfolio. Under the 100 percent renewable portfolio, LACCE customers will pay 6.3 percent more for their power, but will receive roughly four times as much renewable energy compared to the SCE product. The projected LACCE and SCE rates are illustrated in Exhibit 42.

Exhibit 42
Indicative Rate Comparison ($/kWh)

Rate Class	SCE Bundled Rate*	LACCE RPS Bundled Rate	LACCE 50% Green Bundled Rate	LACCE 100% Green Bundled Rate
Residential	17.1	16.2	16.4	18.2
GS-1	16.6	15.7	15.9	17.7
GS-2	15.8	15.0	15.2	16.9
GS-3	14.5	13.8	13.9	15.5
PA-2	12.6	12.0	12.1	13.4
PA-3	10.4	9.9	10.0	11.1
TOU-8 Secondary	13.1	12.4	12.6	14.0
TOU-8 Primary	11.7	11.1	11.2	12.5
TOU-8 Substation	7.5	7.1	7.2	8.0
Total LACCE Rate Savings		5.4%	4.1%	(6.3%)

*SCE bundled average rate based on Table 3 in Advice 3319-E-A.

As an alternative to its standard rates with 28 percent renewable power, SCE also offers rates which feature 50 percent and 100 percent renewable power. For the residential customers, SCE estimates energy costs to be 3.5 cents per kWh higher for each kWh served on the green rate. The LACCE rates for 50 percent and 100 percent renewable power for residential customers are therefore estimated at 12-13% percent lower than SCE's.

Once LACCE gives notice to SCE that it will commence service, LACCE customers will not be responsible for costs associated with SCE's future electricity procurement contracts or power plant investments.[6] This is a distinct advantage to LACCE customers as they will now have local control of power supply costs through LACCE.

Renewable Energy Impacts

A second consequence of forming LACCE will be an increase in the proportion of energy generated and supplied by renewable resources. The Plan includes procurement of renewable energy sufficient to meet 50 percent or more of LACCE's electricity needs. The majority of this renewable energy will be met by new renewable resources. By 2020, SCE must procure a minimum of 33 percent of its customers' annual electricity usage from renewable resources due to the state Renewable Portfolio Standard and the Energy Action Plan requirements of the CPUC. In contrast, LACCE will target 50 percent renewable by 2017 and these resources will likely be new renewable resources.

Energy Efficiency Impacts

A third consequence of forming LACCE will be an increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by SCE are not expected to change as a result of forming LACCE. LACCE customers will continue to pay the public goods charges to SCE which funds energy efficiency programs for all customers, regardless of supplier. The energy efficiency programs ultimately planned for LACCE will be in addition to the level of investment that would continue in the absence of LACCE. Thus, LACCE has the potential for increased energy investment and savings with an attendant further reduction in emissions due to expanded energy efficiency programs.

Economic Development Impacts

The fourth consequence of forming LACCE will be enhanced local economic development. The analyses contained in this Plan has focused primarily on the direct effects of this formation. However, in addition to direct effects, indirect economic effects are also encountered. The indirect effects of creating LACCE include the effects of increased local investments, increased disposable income due to bill savings and improved environmental and health conditions.

Exhibit 43 shows the effects $20 million in electric bill savings will have on the County's economy. The $20 million rate savings represents the minimum bill savings per year achievable by LACCE once in full operation. It is estimated that the electric bill savings can create approximately 211 additional jobs in the County with over $9.6 million in labor income. It is also projected that the total value added will be approximately $15.9 million and output close to $24.2 million.

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

Exhibit 43 $20 Million Rate Savings Effects on County Economy				
Impact Type	**Employment**	**Labor Income**	**Total Value Added**	**Output**
Direct Effect	98.3	$3,674,939	$5,376,863	$7,099,612
Indirect Effect	10.4	$608,838	$1,057,593	$1,677,591
Induced Effect	102.1	$5,319,262	$9,472,599	$15,391,851
Total Effect	210.7	$9,603,040	$15,907,056	$24,169,054

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand.

In addition to increased economic activity due to electric bill savings, potential local projects can also create job and economic growth in the local economy. As an example of the macroeconomic activity caused by local DER deployment, this Plan assumes the installation of fifty crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. Overall, the building of this one solar project is projected to create $87 million in earnings and $188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. It is anticipated that LACCE will ultimately install a number of larger local solar projects such as the one described. At full Phase 3 build-out, the positive economic impacts could be 6-7 times larger than those calculated for Phase 2 operations.

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

The fifth consequence of forming LACCE will be reduced GHG emissions. The amount of renewable power in SCE's power supply portfolio is 28 percent[7] and will rise to 33 percent by 2020. LACCE is committed to reductions in greenhouse gas emissions. Based on power supply strategy described previously, the estimated GHG emission reductions are forecast to range from 289,080 to 505,890 tons CO_2e per year by 2019 assuming a 50 percent RPS target is achieved. The baseline for comparison is the resource mix used by SCE versus the resource mix that will be utilized by LACCE. Exhibit 44 details these reductions.

[7] http://www.cpuc.ca.gov/RPS_Homepage/

Exhibit 44 Baseline Comparison of GHG Reduction by LACCE			
	2017	**2018**	**2019**
Forecast Renewables (50% Renewables) LACCE (MWH) – Phase 2	1,438,275	1,459,854	1,459,854
LACCE RPS (MWH) – Phase 2	730,029	737,154	737,154
Additional Green Power	708,246	722,700	722,700
CO2 reduction – Low (Metric Tons of CO_2e)	283,298	289,080	289,080
CO2 reduction – High (Metric tons of CO_2e)	495,772	505,890	505,890

These reductions in GHG emissions associated with LACCE operations are significant. Assuming only Phase 2 loads (all unincorporated County loads) are being met by LACCE, CO_2e emissions associated with in-County electricity use will be reduced by 1-2 percent. At full Phase 3 build-out, CO_2 emissions associated with in-County electricity use will be reduced roughly 12-25 percent by LACCE operations.

Summary

This study concludes that the formation of a CCA in Los Angeles County is financially feasible and would yield considerable benefits for all participating County residents and businesses. These benefits could include 4.1 percent lower rates for electricity that is supplied by roughly twice the amount of renewable resources as SCE. LACCE will reduce GHG emissions by as much as 500,000 tons of CO_2e per year by serving only the County's unincorporated areas. At full build-out, a 2 percent rate reduction (a fraction of the total reduction possible) will add 211 jobs, generate over $24.2 million in additional GDP, and give the County and its residents greater control over their power supply and energy efficiency programs. The positive impacts on the County and its inhabitants of forming LACCE are so significant that this effort should be pursued. No likely combination of sensitivities will change this recommendation.

Appendix A – Cities/Counties Evaluating CCA Feasibility

	CCA Name	Service Area	Start Date	IOU
Operational				
	Marin Clean Energy	Marin County, Napa County, part of Contra Costa and Solano Counties	May 2010	PG&E
	Sonoma Clean Power	Sonoma County	May 2014	PG&E
	Lancaster Choice Energy	City of Lancaster	May 2015	SCE
	Clean Power San Francisco	City of San Francisco	May 2016	PG&E
	Peninsula Clean Energy	San Mateo County	June 2016	PG&E
Exploring/In Process				
	East Bay Community Energy	Alameda County		PG&E
	TBD	Butte County		PG&E
	TBD	City of San Jose		PG&E
	TBD	Contra Costa County		PG&E
	TBD	Humboldt County		PG&E
	LA Community Choice Energy	LA County		SCE
	TBD	Mendocino County		PG&E
	TBD	Monterey County		PG&E
	TBD	Placer County		PG&E
	TBD	Riverside County		SCE
	TBD	San Benito County		PG&E
	TBD	San Bernardino County		SCE
	TBD	San Diego County		SDG&E
	TBD	San Luis Obispo County		PG&E
	TBD	Santa Barbara County		SCE/PG&E
	Silicon Valley Clean Energy	Santa Clara County		PG&E
	TBD	Santa Cruz County		PG&E

Appendix B – CCA Funding Options Prepared by Public Financial Management, Inc.

This Appendix C is provided by Public Financial Management, Inc., the energy programs financial advisor to the Office of Sustainability hired to assist in LACCE start-up activities.

LACCE has funding requirements at each Phase of the program, including initial start-up costs as well as working capital necessary to bridge the timing lag between initial power purchases and the receipt of customer revenues. The complexity and availability of funding opportunities is influenced by the nature of each Phase of the program and the core structural features of the LACCE program itself. The discussion that follows reviews the current state of the financial marketplace for CCA programs and the funding options available to LACCE for each Phase of the program, as well as an overview of how other California CCAs have approached start-up and launch phase funding requirements.

Overview of Funding Requirements

Start-Up/Phase 1 – Start-Up and Phase 1 funding requirements are estimated to be approximately $10 million. This amount consists of initial capital needs for infrastructure to establish the CCA as well as working capital to fund initial power procurement related expenses and bridge the timing lag between payment deadlines and the receipt of the first customer revenues. Phase 1 is expected to launch January 1, 2017, but funds will be required pre-launch starting on or about July 1, 2016 or later if some start-up costs can continue to be covered by initial County funding to develop the Business Plan.

Phase 2 – Phase 2 is scheduled to launch six months after Phase 1 on or about July 1, 2017. Phase 2 funding requirements are estimated to be approximately $40 million largely oriented towards working capital and credit support for power procurement expenses. Similar to the Phase 1 timing, financing will be required several months prior to the launch of Phase 2. The lending community will view both Phase 1 and Phase 2 as having elevated risk profiles, given the start-up nature of the enterprise and uncertainty with respect to customer opt-out rates. On a relative basis, Phase 1 carries additional funding risk as a result of risks associated with failure to launch and untested revenue estimates, while the risk profile of Phase 2 should benefit from a limited history of successful collections and operating results as well as the ability to cure any preliminary start-up issues during the Phase 1 limited launch.

Current CCA Funding Landscape

The CCA market is rapidly expanding with increasingly proven success. To date, there are four operational CCAs in California with varying degrees of operating histories; however, all four CCAs have demonstrated the ability to generate positive operating results. As a result, power providers have kept pace and expanded their comfort level with CCA counterparty risks, offering elongated and more flexible repayment terms for initial power purchases. The same cannot yet be said for the financial marketplace. To date, the financial counterparties who have gotten comfortable with CCA counterparty risk are very limited with only 3 to 5 banks currently offering credit to CCAs in the startup phase. The early adopters were community banks in the CCA service territory. In recent months a mix of regional and large national banks have shown increased levels of interest, particularly towards CCAs with (i) longer operating track-records and (ii) larger service territories. This expanded financial counterparty base should give LACCE comfort that it will have access to a deeper pool of potential financial counterparties than previous programs.

This is especially important since the LACCE program will dwarf all programs launched to date with respect to load served and potential customer base and thus require greater dollars.

Why are banks hesitant to lend to CCAs? LACCE will be formed as a Joint Action Agency (JPA) which is a proven organizational construct within California. Hundreds of JPAs have been created in CA and used to access billions in capital dollars over the decades. In particular, public power utilities in Southern California have sold billions of dollars of tax-exempt bonds and have had access to bank credit support in the form of letters and lines of credit. The key differentiating feature between all of these entities and a CCA is a monopoly right to a revenue stream to repay their creditors. Based on the existing legislative construct, CCAs have opt-out risk which gives creditors pause for concern. This is the fundamental reason why the financial marketplace has yet to get comfortable with CCAs on a broad-based basis.

As CCAs have successfully launched across the state and a more robust data set of opt-out history becomes available, the financial community has been more comfortable to provide credit support to CCAs. As more and larger opportunities such as LACCE, San Francisco, San Mateo County and San Diego potentially become available it is driving the financial community to respond and adapt. To date, the financial community as a whole has essentially been unaware of the growing CCA opportunity. Additional outreach and large scale public procurement efforts will continue to educate the marketplace.

With respect LACCE, funding requirements for start-up, Phase 1 and Phase 2 will be difficult funds to procure from a third party lender without some form of credit support (discussed below). The lending community will view the Start-up/Phase 1 $10MM investment as high-risk because the CCA has yet to launch and begin collecting revenues which would be available to repay the lender. This investment is viewed much like an investment in any other start-up company that may not get off the ground. Phase 2 needs become a bit less risky as an operating history is established, but this history will be very limited and a significant amount of risk still exists for any lender. Future phases will reap the benefits of early Phase success and a reduced risk profile as LACCE demonstrates a record of operating results.

As a result of these funding challenges, all programs that have launched to date and those in development have relied on a sponsoring municipality to provide support for obtaining these needed funds. This support has come in varied forms which are summarized in Exhibit B-1 below:

Exhibit B-1 Forms of Support		
Existing CCAs	**Start-Up Funding Requirement[1]**	**Funding Sources**
MCE 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.
CleanPower SF	~$5 million	Appropriations from the Hetch Hetchy reserve (SFPUC).
Lancaster Choice CCA	~$2 million	Loan from the City of Lancaster general fund.
Peninsula Clean Energy	$10 - $12 million	San Mateo County has stated a willingness to fund a $6MM escrow to secure lenders.

[1] Source: Respective entity websites and publicly available information.

Funding Option Review

LACCE will have more options than the initial CCA efforts in the state; however, the fundamental marketplace developments described above will nevertheless influence LACCE's financing alternatives. This is a very dynamic and rapidly evolving market so what is written here will likely be different and perhaps more favorable when LACCE moves toward launch.

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

Direct Loan from LA County – LACCE can approach LA County for a loan to fund all or a portion of the Start-up/Phase 1 and Phase 2 needs. The County would be secured by the CCA revenues once launched. LA County could expect to be repaid in one to three years for this investment based on the history of other operational CCAs. LA County would likely assess a risk-appropriate rate for such a loan which is likely higher than the County earns for funds otherwise invested. This rate is estimated to be 4.0 percent to 6.0 percent.

Phase 1 needs are wholly County-contained risks in that the CCA is serving power to County facilities. This is a very controlled risk for the County in that it is essentially both the lender and the creditor. The opt-out risk is completely in the County's control. While untested, it is possible that a lender other than the County could be found to fund these needs. Should the County be willing to offer up additional credit protection in the form of a 3-year agreement to not opt-out of the CCA, then external funding sources may be more readily available. The loan at that point would be no different than a loan to the County's general fund, which has ample access to bank credit, given its high investment grade credit ratings and strong credit profile.

Phase 2 needs are broader and exposed to opt-out risk of customers beyond the County's control. A direct loan from the County would be the easiest and most reliable approach to funding for LACCE Phase 2. The County will need to assess such risk appropriately and, if it decides to fund a loan, should fund at levels that reflect such risk. This has ranged 4.0 percent to 6.0 percent as noted above. To date, the tenor of such loans has been relatively short, albeit with somewhat flexible repayment terms. The County would have other vehicles described below to support the CCA while limiting its risk.

Collateral Arrangement from LA County – As an alternative to a direct loan from the County, the County could establish an escrow account to backstop a lender's exposure to the CCA. The County would agree to deposit funds in an interest-bearing escrow account which the lender could tap should the CCA fail to pay the lender directly.

The escrow would be interest bearing on behalf of the County so to the extent funds are not used the County is not forgoing interest earnings or principal. The amount of deposit required is negotiable with the lenders but could be as high as 50 percent of the loan needs or $12.5 million to $20 million for Phase 2. This limits the County's exposure to 50 percent vs 100 percent direct exposure with a loan. This arrangement will attract interest form the existing CCA lending community and likely bring additional competition via a lending procurement effort.

Loan from a Financial Institution without Support – Market appetite for this option at such an early stage of the CCA is untested. To date, only CCAs with a more extensive 2 to 3-year operating history have been able to move away from a supported funding arrangement. LACCE should nonetheless explore this option.

Vendor Funding – LACCE can pursue arrangements with its power suppliers to eliminate or reduce the need for or size of funding for the initial Phases. This could come in a number of forms such as a "lockbox" approach with one power provider or a "credit-sleeving" approach with a power marketer. However, this approach is less transparent and the associated cost may outweigh the benefit of eliminating or reducing the need for a bank facility. It has been a very viable approach for the first CCA programs, but with the expansion of the marketplace it may not be required.

Revenue Bond Financing – This is not a feasible option at this point given the start-up nature of the enterprise. Once the CCA is more established (3 to 5 years) and can obtain a credit rating this could be an avenue to explore for future capital needs. Other CCAs with a longer operating history will likely explore and establish this marketplace before LACCE.

Summary

Funding for the LACCE program is available and viable in various forms as the financial marketplace continues to evolve for CCAs. The program should explore all options to determine which alternatives or combination of alternatives delivers the lowest cost funding.

Phase 1 needs are best supported by LA County as the sole impacted CCA participant. There are options beyond this, but each involves a significant amount of risk for the counterparty and thus likely to be available at a higher cost for LACCE.

Phase 2 needs will greatly benefit from an LA County pledge, but the marketplace may allow alternatives as noted above.

Appendix C – Proforma Analyses

LA County Community Choice Aggregation
Financial Proforma
Portfolio - 50% Renewable

	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Load Data																					
Customer Accounts																					
Domestic	43	279,478	286,656	287,449	290,158	294,277	299,063	305,491	312,692	320,160	328,122	335,746	341,378	347,105	352,928	358,849	364,870	370,991	377,215	383,543	389,978
Commercial	925	27,673	27,902	28,199	28,489	28,718	28,942	29,276	29,511	29,754	30,031	30,222	30,514	30,809	31,107	31,408	31,711	32,018	32,328	32,641	32,957
Industrial	10	135	135	135	135	134	134	134	134	134	134	134	134	134	134	133	133	133	133	133	133
Lighting & Traffic Control	686	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288
Agricultural	64	984	986	989	991	994	997	1,000	1,003	1,005	1,008	1,011	1,014	1,017	1,020	1,023	1,025	1,028	1,031	1,034	1,037
Total Customers	1,728	309,558	316,966	318,060	321,061	325,412	330,424	337,189	344,628	352,341	360,583	368,401	374,328	380,353	386,477	392,701	399,028	405,459	411,995	418,639	425,393
Energy Sales (MWh)																					
Domestic	86	825,737	1,486,894	1,500,905	1,522,211	1,546,971	1,580,223	1,617,470	1,656,100	1,697,285	1,736,723	1,765,859	1,795,484	1,825,607	1,856,234	1,887,376	1,919,040	1,951,236	1,983,971	2,017,256	2,051,099
Commercial	23,544	439,958	828,482	836,747	843,298	849,674	859,196	865,918	872,855	880,765	886,220	894,552	902,966	911,464	920,047	928,716	937,471	946,313	955,243	964,262	973,371
Industrial	42,848	222,120	415,784	415,082	413,882	412,796	413,483	413,405	412,993	413,065	412,935	412,646	412,357	412,068	411,779	411,491	411,203	410,915	410,628	410,341	410,054
Lighting & Traffic Control	12,604	19,547	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444
Agricultural	4,917	55,425	103,471	103,750	104,029	104,310	104,591	104,873	105,156	105,439	105,724	106,009	106,295	106,582	106,870	107,159	107,448	107,739	108,030	108,322	108,615
Total Energy Sales (MWh)	83,998	1,562,787	2,873,075	2,894,927	2,921,864	2,952,194	2,995,937	3,040,110	3,085,547	3,134,997	3,180,045	3,217,509	3,255,546	3,294,165	3,333,375	3,373,185	3,413,606	3,454,646	3,496,316	3,538,625	3,581,583
	2017 Jan - June	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
CCE Operating Costs																					
Power Supply	$5,115,141	$78,575,785	$147,670,090	$151,208,630	$155,034,198	$159,257,906	$164,317,538	$169,532,598	$175,061,789	$181,154,265	$186,972,696	$192,469,336	$198,332,840	$204,691,824	$211,012,300	$217,680,878	$224,618,939	$231,778,097	$239,348,954	$247,253,173	$255,387,886
Billing & Data Management	$12,960	$2,321,688	$4,754,496	$4,770,904	$4,815,913	$4,881,173	$4,956,358	$5,057,834	$5,169,415	$5,285,118	$5,408,747	$5,526,017	$5,614,925	$5,705,295	$5,797,151	$5,890,517	$5,985,418	$6,081,880	$6,179,928	$6,279,589	$6,380,890
SCE Fees	$1,106,742	$230,000	$1,559,583	$1,564,964	$1,579,727	$1,601,133	$1,625,793	$1,659,077	$1,695,676	$1,733,627	$1,774,177	$1,812,641	$1,841,803	$1,871,445	$1,901,574	$1,932,198	$1,963,325	$1,994,965	$2,027,124	$2,059,813	$2,093,040
Technical Services	$715,000	$715,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000
Staffing	$380,000	$1,215,000	$3,396,600	$3,464,532	$3,533,823	$3,604,499	$3,676,589	$3,750,121	$3,825,123	$3,901,626	$3,979,658	$4,059,251	$4,140,436	$4,223,245	$4,307,710	$4,393,864	$4,481,742	$4,571,376	$4,662,804	$4,756,060	$4,851,181
General & Administrative expenses	$160,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698	$373,012	$380,473	$388,082	$395,844	$403,761	$411,836	$420,072	$428,474	$437,043
Debt Service (CCE Bonds & Start-up Costs)	$3,514,532	$3,514,532	$7,029,064	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532
Start-Up Capital	($5,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$58,598	$500,548	$953,462	$954,270	$974,531	$997,343	$1,024,971	$971,640	$1,000,666	$1,032,673	$1,063,290	$1,092,187	$1,122,723	$1,155,747	$1,188,726	$1,223,367	$1,259,378	$1,296,514	$1,335,729	$1,376,632	$1,418,720
Total Operating Costs	$6,062,973	$87,302,553	$167,149,294	$167,219,951	$171,201,087	$175,611,316	$180,877,005	$186,253,651	$192,041,806	$198,403,338	$204,501,628	$210,269,662	$216,370,272	$222,972,560	$229,540,074	$236,461,199	$243,657,094	$251,079,199	$258,919,144	$267,098,274	$275,513,292
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$6,062,973	$87,302,553	$167,149,294	$167,219,951	$171,201,087	$175,611,316	$180,877,005	$186,253,651	$192,041,806	$198,403,338	$204,501,628	$210,269,662	$216,370,272	$222,972,560	$229,540,074	$236,461,199	$243,657,094	$251,079,199	$258,919,144	$267,098,274	$275,513,292
Average CCE Rate ($/kWh)		$0.0530	$0.0582	$0.0578	$0.0586	$0.0595	$0.0604	$0.0613	$0.0622	$0.0633	$0.0643	$0.0654	$0.0665	$0.0677	$0.0689	$0.0701	$0.0714	$0.0727	$0.0741	$0.0755	$0.0769
Average SCE Generation Rate ($/kWh)		$0.0684	$0.0692	$0.0709	$0.0734	$0.0750	$0.0767	$0.0785	$0.0805	$0.0823	$0.0841	$0.0858	$0.0875	$0.0894	$0.0908	$0.0926	$0.0946	$0.0965	$0.0986	$0.1008	$0.1029
Total CCE Charges																					
SCE Non-bypassable Charges	$715,270	$13,307,632	$24,496,470	$24,588,226	$24,679,691	$24,854,670	$25,142,156	$9,046,076	$9,091,988	$9,163,882	$9,219,721	$9,259,956	$9,297,027	$9,332,491	$9,393,772	$9,435,616	$9,477,832	$9,520,054	$9,562,324	$9,604,837	$9,649,378
CCE Revenue Requirement	$6,062,973	$87,302,553	$167,149,294	$167,219,951	$171,201,087	$175,611,316	$180,877,005	$186,253,651	$192,041,806	$198,403,338	$204,501,628	$210,269,662	$216,370,272	$222,972,560	$229,540,074	$236,461,199	$243,657,094	$251,079,199	$258,919,144	$267,098,274	$275,513,292
Total CCE Generation Revenue Requirement	$6,778,244	$100,610,186	$191,645,765	$191,808,177	$195,880,777	$200,465,986	$206,019,161	$195,299,727	$201,133,794	$207,567,220	$213,721,348	$219,529,618	$225,667,299	$232,305,051	$238,933,846	$245,896,815	$253,134,927	$260,599,253	$268,481,467	$276,703,111	$285,162,670
Bundled SCE Revenues	$13,222,230	$246,000,134	$462,690,313	$476,602,301	$494,417,741	$510,735,421	$530,026,448	$550,333,342	$572,141,453	$594,470,424	$616,770,113	$637,141,478	$658,526,273	$680,869,244	$702,056,698	$725,605,074	$750,044,967	$775,447,673	$801,854,568	$829,294,440	$857,637,876
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$12,680,167	$235,915,032	$443,865,280	$456,869,595	$473,336,572	$488,673,425	$506,842,962	$525,968,140	$546,452,655	$567,524,699	$588,543,233	$607,770,036	$627,923,408	$648,959,453	$669,089,958	$691,296,020	$714,336,051	$738,273,377	$763,146,083	$788,981,674	$815,673,277
Savings	**$542,063**	**$10,085,102**	**$18,825,033**	**$19,732,707**	**$21,081,169**	**$22,061,996**	**$23,183,486**	**$24,365,202**	**$25,688,798**	**$26,945,725**	**$28,226,879**	**$29,371,443**	**$30,602,865**	**$31,909,791**	**$32,966,740**	**$34,309,054**	**$35,708,916**	**$37,174,296**	**$38,708,485**	**$40,312,767**	**$41,964,598**
Percent Savings	**4.1%**	**4.1%**	**4.1%**	**4.1%**	**4.3%**	**4.3%**	**4.4%**	**4.4%**	**4.5%**	**4.5%**	**4.6%**	**4.6%**	**4.6%**	**4.7%**	**4.7%**	**4.7%**	**4.8%**	**4.8%**	**4.8%**	**4.9%**	**4.9%**

LA County Community Choice Aggregation
Financial Proforma
Portfolio - RPS

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts																					
Domestic	43	279,478	286,656	287,449	290,158	294,277	299,063	305,491	312,692	320,160	328,122	335,746	341,378	347,105	352,928	358,849	364,870	370,991	377,215	383,543	389,978
Commercial	925	27,673	27,902	28,199	28,489	28,718	28,942	29,276	29,511	29,754	30,031	30,222	30,514	30,809	31,107	31,408	31,711	32,018	32,328	32,641	32,957
Industrial	10	135	135	135	135	134	134	134	134	134	134	134	134	134	134	133	133	133	133	133	133
Lighting & Traffic Control	686	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288
Agricultural	64	984	986	989	991	994	997	1,000	1,003	1,005	1,008	1,011	1,014	1,017	1,020	1,023	1,025	1,028	1,031	1,034	1,037
Total Customers	1,728	309,558	316,966	318,060	321,061	325,412	330,424	337,189	344,628	352,341	360,583	368,401	374,328	380,353	386,477	392,701	399,028	405,459	411,995	418,639	425,393
Energy Sales (MWh)																					
Domestic	86	825,737	1,486,894	1,500,905	1,522,211	1,546,971	1,580,223	1,617,470	1,656,100	1,697,285	1,736,723	1,765,859	1,795,484	1,825,607	1,856,234	1,887,376	1,919,040	1,951,236	1,983,971	2,017,256	2,051,099
Commercial	23,544	439,958	828,482	836,747	843,298	849,674	859,196	865,918	872,855	880,765	886,220	894,552	902,966	911,464	920,047	928,716	937,471	946,313	955,243	964,262	973,371
Industrial	42,848	222,120	415,784	415,082	413,882	412,796	413,483	413,405	412,993	413,065	412,935	412,646	412,357	412,068	411,779	411,491	411,203	410,915	410,628	410,341	410,054
Lighting & Traffic Control	12,604	19,547	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444
Agricultural	4,917	55,425	103,471	103,750	104,029	104,310	104,591	104,873	105,156	105,439	105,724	106,009	106,295	106,582	106,870	107,159	107,448	107,739	108,030	108,322	108,615
Total Energy Sales (MWh)	83,998	1,562,787	2,873,075	2,894,927	2,921,864	2,952,194	2,995,937	3,040,110	3,085,547	3,134,997	3,180,045	3,217,509	3,255,546	3,294,165	3,333,375	3,373,185	3,413,606	3,454,646	3,496,316	3,538,625	3,581,583
CCE Operating Costs	**2017 Jan - June**	**2017 July - Dec**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Power Supply	$5,110,839	$74,072,864	$139,247,657	$143,573,115	$149,887,088	$154,656,623	$160,300,239	$166,177,870	$172,701,936	$179,005,281	$185,335,719	$190,997,414	$197,061,702	$203,479,087	$208,779,585	$215,379,743	$222,252,573	$229,434,741	$236,941,797	$244,780,164	$252,847,304
Billing & Data Management	$12,960	$2,321,688	$4,754,496	$4,770,904	$4,815,913	$4,881,173	$4,956,358	$5,057,834	$5,169,415	$5,285,118	$5,408,747	$5,526,017	$5,614,925	$5,705,295	$5,797,151	$5,890,517	$5,985,418	$6,081,880	$6,179,928	$6,279,589	$6,380,890
SCE Fees	$1,106,742	$230,000	$1,559,583	$1,564,964	$1,579,727	$1,601,133	$1,625,793	$1,659,077	$1,695,676	$1,733,627	$1,774,177	$1,812,641	$1,841,803	$1,871,445	$1,901,574	$1,932,198	$1,963,325	$1,994,965	$2,027,124	$2,059,813	$2,093,040
Technical Services	$715,000	$715,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000
Staffing	$380,000	$1,215,000	$3,396,600	$3,464,532	$3,533,823	$3,604,499	$3,676,589	$3,750,121	$3,825,123	$3,901,626	$3,979,658	$4,059,251	$4,140,436	$4,223,245	$4,307,710	$4,393,864	$4,481,742	$4,571,376	$4,662,804	$4,756,060	$4,851,181
General & Administrative expenses	$160,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698	$373,012	$380,473	$388,082	$395,844	$403,761	$411,836	$420,072	$428,474	$437,043
Debt Service (CCE Bonds & Start-up Costs)	$3,514,532	$3,514,532	$7,029,064	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532
Start-Up Capital	($5,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$58,577	$478,034	$911,349	$916,092	$948,796	$974,337	$1,004,884	$954,867	$988,866	$1,021,928	$1,055,105	$1,084,828	$1,116,367	$1,149,683	$1,177,562	$1,211,862	$1,247,546	$1,284,797	$1,323,693	$1,364,267	$1,406,017
Total Operating Costs	$6,058,650	$82,777,118	$158,684,749	$159,546,259	$166,028,241	$170,987,026	$176,839,620	$182,882,150	$189,670,154	$196,243,610	$202,856,466	$208,790,381	$215,092,779	$221,753,760	$227,296,195	$234,148,558	$241,278,895	$248,724,126	$256,499,951	$264,612,900	$272,960,008
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$6,058,650	$82,777,118	$158,684,749	$159,546,259	$166,028,241	$170,987,026	$176,839,620	$182,882,150	$189,670,154	$196,243,610	$202,856,466	$208,790,381	$215,092,779	$221,753,760	$227,296,195	$234,148,558	$241,278,895	$248,724,126	$256,499,951	$264,612,900	$272,960,008
Average CCE Rate ($/kWh)		$0.0503	$0.0552	$0.0551	$0.0568	$0.0579	$0.0590	$0.0602	$0.0615	$0.0626	$0.0638	$0.0649	$0.0661	$0.0673	$0.0682	$0.0694	$0.0707	$0.0720	$0.0734	$0.0748	$0.0762
Average SCE Generation Rate ($/kWh)		$0.0684	$0.0692	$0.0709	$0.0734	$0.0750	$0.0767	$0.0785	$0.0805	$0.0823	$0.0841	$0.0858	$0.0875	$0.0894	$0.0908	$0.0926	$0.0946	$0.0965	$0.0986	$0.1008	$0.1029
Total CCE Charges																					
SCE Non-bypassable Charges	$715,270	$13,307,632	$24,496,470	$24,588,226	$24,679,691	$24,854,670	$25,142,156	$9,046,076	$9,091,988	$9,163,882	$9,219,721	$9,259,956	$9,297,027	$9,332,491	$9,393,772	$9,435,616	$9,477,832	$9,520,054	$9,562,324	$9,604,837	$9,649,378
CCE Revenue Requirement	$6,058,650	$82,777,118	$158,684,749	$159,546,259	$166,028,241	$170,987,026	$176,839,620	$182,882,150	$189,670,154	$196,243,610	$202,856,466	$208,790,381	$215,092,779	$221,753,760	$227,296,195	$234,148,558	$241,278,895	$248,724,126	$256,499,951	$264,612,900	$272,960,008
Total CCE Generation Revenue Requirement	$6,773,920	$96,084,750	$183,181,219	$184,134,485	$190,707,932	$195,841,697	$201,981,776	$191,928,225	$198,762,142	$205,407,491	$212,076,187	$218,050,337	$224,389,806	$231,086,250	$236,689,967	$243,584,175	$250,756,728	$258,244,180	$266,062,274	$274,217,737	$282,609,386
Bundled SCE Revenues	$13,222,230	$246,000,134	$462,690,313	$476,602,301	$494,417,741	$510,735,421	$530,026,448	$550,333,342	$572,141,453	$594,470,424	$616,770,113	$637,141,478	$658,526,273	$680,869,244	$702,056,698	$725,605,074	$750,044,967	$775,447,673	$801,854,568	$829,294,440	$857,637,876
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$12,507,756	$232,707,322	$437,900,502	$450,715,892	$466,905,427	$482,029,638	$499,947,775	$518,808,581	$538,999,629	$559,786,926	$580,518,962	$599,491,879	$619,373,431	$640,121,821	$660,012,706	$681,922,162	$704,653,177	$728,267,445	$752,802,338	$778,285,044	$804,613,140
Savings	**$714,474**	**$13,292,812**	**$24,789,811**	**$25,886,409**	**$27,512,314**	**$28,705,783**	**$30,078,674**	**$31,524,761**	**$33,141,824**	**$34,683,498**	**$36,251,151**	**$37,649,600**	**$39,152,842**	**$40,747,422**	**$42,043,993**	**$43,682,912**	**$45,391,791**	**$47,180,229**	**$49,052,230**	**$51,009,396**	**$53,024,736**
Percent Savings	**5.4%**	**5.4%**	**5.4%**	**5.4%**	**5.6%**	**5.6%**	**5.7%**	**5.7%**	**5.8%**	**5.8%**	**5.9%**	**5.9%**	**5.9%**	**6.0%**	**6.0%**	**6.0%**	**6.1%**	**6.1%**	**6.1%**	**6.2%**	**6.2%**

LA County Community Choice Aggregation
Financial Proforma
Portfolio - 100% Renewable

Load Data	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts																					
Domestic	43	279,478	286,656	287,449	290,158	294,277	299,063	305,491	312,692	320,160	328,122	335,746	341,378	347,105	352,928	358,849	364,870	370,991	377,215	383,543	389,978
Commercial	925	27,673	27,902	28,199	28,489	28,718	28,942	29,276	29,511	29,754	30,031	30,222	30,514	30,809	31,107	31,408	31,711	32,018	32,328	32,641	32,957
Industrial	10	135	135	135	135	134	134	134	134	134	134	134	134	134	134	133	133	133	133	133	133
Lighting & Traffic Control	686	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288	1,288
Agricultural	64	984	986	989	991	994	997	1,000	1,003	1,005	1,008	1,011	1,014	1,017	1,020	1,023	1,025	1,028	1,031	1,034	1,037
Total Customers	1,728	309,558	316,966	318,060	321,061	325,412	330,424	337,189	344,628	352,341	360,583	368,401	374,328	380,353	386,477	392,701	399,028	405,459	411,995	418,639	425,393
Energy Sales (MWh)																					
Domestic	86	825,737	1,486,894	1,500,905	1,522,211	1,546,971	1,580,223	1,617,470	1,656,100	1,697,285	1,736,723	1,765,859	1,795,484	1,825,607	1,856,234	1,887,376	1,919,040	1,951,236	1,983,971	2,017,256	2,051,099
Commercial	23,544	439,958	828,482	836,747	843,298	849,674	859,196	865,918	872,855	880,765	886,220	894,552	902,966	911,464	920,047	928,716	937,471	946,313	955,243	964,262	973,371
Industrial	42,848	222,120	415,784	415,082	413,882	412,796	413,483	413,405	412,993	413,065	412,935	412,646	412,357	412,068	411,779	411,491	411,203	410,915	410,628	410,341	410,054
Lighting & Traffic Control	12,604	19,547	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444	38,444
Agricultural	4,917	55,425	103,471	103,750	104,029	104,310	104,591	104,873	105,156	105,439	105,724	106,009	106,295	106,582	106,870	107,159	107,448	107,739	108,030	108,322	108,615
Total Energy Sales (MWh)	83,998	1,562,787	2,873,075	2,894,927	2,921,864	2,952,194	2,995,937	3,040,110	3,085,547	3,134,997	3,180,045	3,217,509	3,255,546	3,294,165	3,333,375	3,373,185	3,413,606	3,454,646	3,496,316	3,538,625	3,581,583

CCE Operating Costs	2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Power Supply	$6,007,321	$106,068,728	$198,408,928	$201,450,106	$204,500,269	$208,262,418	$212,887,455	$217,705,763	$222,563,531	$227,944,748	$233,140,721	$237,747,217	$242,462,617	$247,687,986	$252,644,070	$258,072,774	$263,233,933	$269,375,999	$274,892,693	$280,988,647	$286,983,057
Billing & Data Management	$12,960	$2,321,688	$4,754,496	$4,770,904	$4,815,913	$4,881,173	$4,956,358	$5,057,834	$5,169,415	$5,285,118	$5,408,747	$5,526,017	$5,614,925	$5,705,295	$5,797,151	$5,890,517	$5,985,418	$6,081,880	$6,179,928	$6,279,589	$6,380,890
SCE Fees	$1,106,742	$230,000	$1,559,583	$1,564,964	$1,579,727	$1,601,133	$1,625,793	$1,659,077	$1,695,676	$1,733,627	$1,774,177	$1,812,641	$1,841,803	$1,871,445	$1,901,574	$1,932,198	$1,963,325	$1,994,965	$2,027,124	$2,059,813	$2,093,040
Technical Services	$715,000	$715,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000	$1,430,000
Staffing	$380,000	$1,215,000	$3,396,600	$3,464,532	$3,533,823	$3,604,499	$3,676,589	$3,750,121	$3,825,123	$3,901,626	$3,979,658	$4,059,251	$4,140,436	$4,223,245	$4,307,710	$4,393,864	$4,481,742	$4,571,376	$4,662,804	$4,756,060	$4,851,181
General & Administrative expenses	$160,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698	$373,012	$380,473	$388,082	$395,844	$403,761	$411,836	$420,072	$428,474	$437,043
Debt Service (CCE Bonds & Start-up Costs)	$3,514,532	$3,514,532	$7,029,064	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532	$3,514,532
Start-Up Capital	($5,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$63,059	$638,013	$1,207,156	$1,205,477	$1,221,862	$1,242,366	$1,267,821	$1,212,506	$1,238,174	$1,266,625	$1,294,130	$1,318,577	$1,343,372	$1,370,727	$1,396,884	$1,425,327	$1,452,453	$1,484,503	$1,513,447	$1,545,310	$1,576,696
Total Operating Costs	$6,959,614	$114,932,961	$218,141,826	$217,712,635	$220,914,488	$224,860,850	$229,689,773	$234,667,682	$239,781,057	$245,427,774	$250,900,493	$255,773,933	$260,720,698	$266,183,703	$271,380,003	$277,055,055	$282,465,162	$288,865,091	$294,640,601	$301,002,425	$307,266,439
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$6,959,614	$114,932,961	$218,141,826	$217,712,635	$220,914,488	$224,860,850	$229,689,773	$234,667,682	$239,781,057	$245,427,774	$250,900,493	$255,773,933	$260,720,698	$266,183,703	$271,380,003	$277,055,055	$282,465,162	$288,865,091	$294,640,601	$301,002,425	$307,266,439
Average CCE Rate ($/kWh)		$0.0698	$0.0759	$0.0752	$0.0756	$0.0762	$0.0767	$0.0772	$0.0777	$0.0783	$0.0789	$0.0795	$0.0801	$0.0808	$0.0814	$0.0821	$0.0827	$0.0836	$0.0843	$0.0851	$0.0858
Average SCE Generation Rate ($/kWh)		$0.0684	$0.0692	$0.0709	$0.0734	$0.0750	$0.0767	$0.0785	$0.0805	$0.0823	$0.0841	$0.0858	$0.0875	$0.0894	$0.0908	$0.0926	$0.0946	$0.0965	$0.0986	$0.1008	$0.1029
Total CCE Charges																					
SCE Non-bypassable Charges	$715,270	$13,307,632	$24,496,470	$24,588,226	$24,679,691	$24,854,670	$25,142,156	$9,046,076	$9,091,988	$9,163,882	$9,219,721	$9,259,956	$9,297,027	$9,332,491	$9,393,772	$9,435,616	$9,477,832	$9,520,054	$9,562,324	$9,604,837	$9,649,378
CCE Revenue Requirement	$6,959,614	$114,932,961	$218,141,826	$217,712,635	$220,914,488	$224,860,850	$229,689,773	$234,667,682	$239,781,057	$245,427,774	$250,900,493	$255,773,933	$260,720,698	$266,183,703	$271,380,003	$277,055,055	$282,465,162	$288,865,091	$294,640,601	$301,002,425	$307,266,439
Total CCE Generation Revenue Requirement	$7,674,884	$128,240,593	$242,638,296	$242,300,861	$245,594,178	$249,715,521	$254,831,928	$243,713,758	$248,873,045	$254,591,656	$260,120,214	$265,033,889	$270,017,725	$275,516,193	$280,773,774	$286,490,671	$291,942,995	$298,385,145	$304,202,925	$310,607,262	$316,915,817
Bundled SCE Revenues	$13,222,230	$246,000,134	$462,690,313	$476,602,301	$494,417,741	$510,735,421	$530,026,448	$550,333,342	$572,141,453	$594,470,424	$616,770,113	$637,141,478	$658,526,273	$680,869,244	$702,056,698	$725,605,074	$750,044,967	$775,447,673	$801,854,568	$829,294,440	$857,637,876
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$14,059,453	$261,576,714	$491,583,504	$506,099,214	$524,785,738	$541,823,722	$562,004,460	$583,244,616	$606,076,859	$629,426,882	$652,737,405	$673,995,291	$696,323,224	$719,660,507	$741,707,978	$766,286,884	$791,799,049	$818,320,835	$845,896,040	$874,554,708	$904,154,380
Savings	**($837,224)**	**($15,576,580)**	**($28,893,191)**	**($29,496,913)**	**($30,367,997)**	**($31,088,301)**	**($31,978,011)**	**($32,911,274)**	**($33,935,406)**	**($34,956,458)**	**($35,967,292)**	**($36,853,812)**	**($37,796,950)**	**($38,791,263)**	**($39,651,280)**	**($40,681,810)**	**($41,754,081)**	**($42,873,162)**	**($44,041,472)**	**($45,260,268)**	**($46,516,504)**
Percent Savings	**-6.3%**	**-6.3%**	**-6.2%**	**-6.2%**	**-6.1%**	**-6.1%**	**-6.0%**	**-6.0%**	**-5.9%**	**-5.9%**	**-5.8%**	**-5.8%**	**-5.7%**	**-5.7%**	**-5.6%**	**-5.6%**	**-5.6%**	**-5.5%**	**-5.5%**	**-5.5%**	**-5.4%**

Appendix D – Glossary

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

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

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

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

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

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

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

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

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

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

CCEAC: Community Choice Energy Advisory Committee - a committee formed to advise the City of Davis on the best options for pursuing a CCE.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Inter-continental Exchange (ICE): The main electronic trading platform for trading wholesale electricity and gas contracts in the United States. (Also handles trading in other commodities and securities.)

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

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

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

Lancaster Choice Energy (LCE): The most recent California CCE to go-live, exclusively serving the City of Lancaster in Southern California.

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

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

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

MCE: Formerly Marin Clean Energy - the first CCE in California serving Cities within and the Counties of Marin and Napa.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Sonoma Clean Power (SCP): A CCE serving Sonoma County and Sonoma County Cities.

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

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

Weather Adjusted: Normalizing energy use data based on differences in the weather during the time of use. For instance, energy use is expected to be higher on extremely hot days when air conditioning is in higher demand than on days with comfortable temperature. Weather adjustment normalizes for this variation.

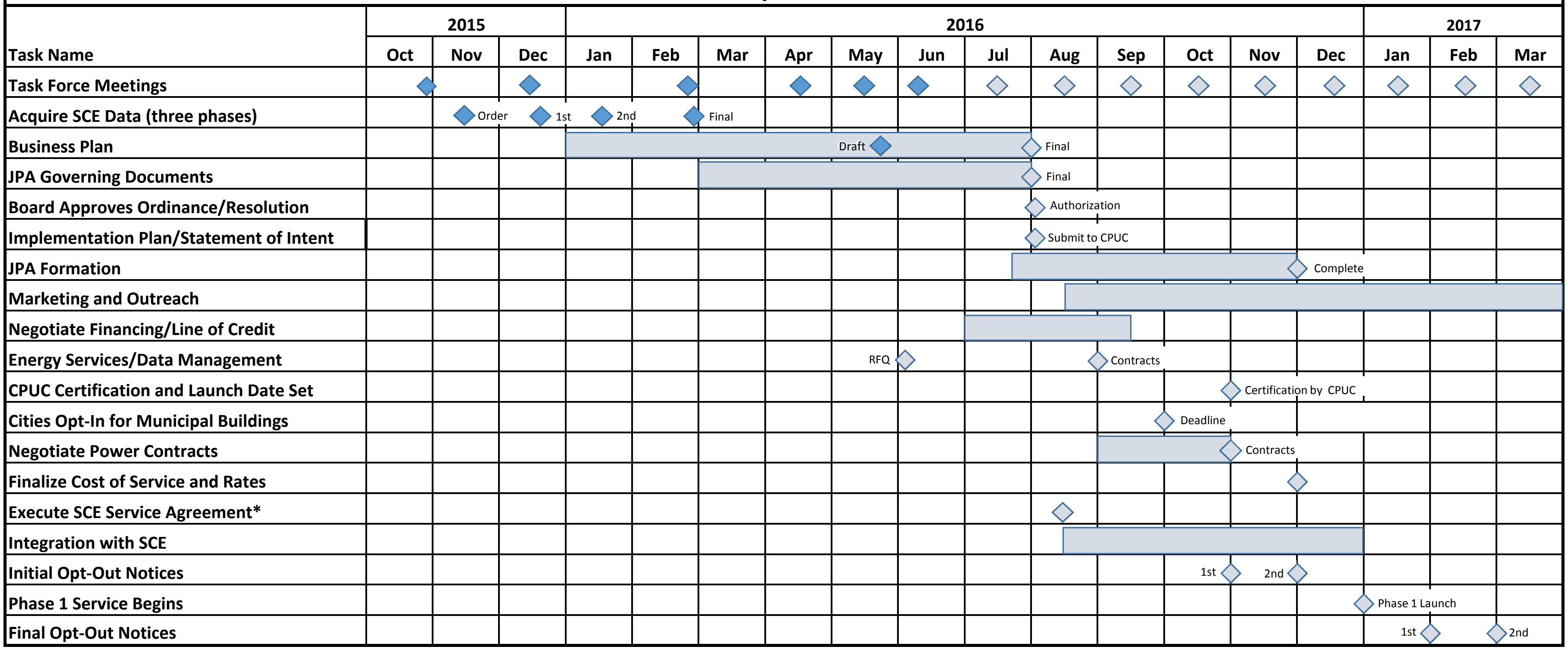
Western Electric Coordinating Council (WECC): The organization responsible for coordinating planning and operation on the Western electric grid.

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

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

ATTACHMENT B

Los Angeles Community Choice Energy (LACCE)
Phase 1 Summary Milestone Schedule



** Includes all required forms and Binding Letter of Intent.*

ATTACHMENT C

Start-Up LACCE Cash Needs for CY 2016

	August	September	October	November	December	Total
IOU Fees (including Billing)	$780	$0	$0	$2,938	$6,203	$9,921
Consultants						
PFM	$25,000	$25,000	$25,000	$25,000	$0	$100,000
Legal/Regulatory	$50,000	$50,000	$50,000	$50,000	$50,000	$250,000
Financial	$25,000	$25,000	$25,000	$25,000	$50,000	$150,000
Advertising/Communication				$10,000	$10,000	$20,000
Services	$20,000	$20,000	$20,000	$20,000	$20,000	$100,000
Staffing	$45,000	$55,000	$55,000	$55,000	$55,000	$265,000
General & Admin	$45,000	$35,000	$25,000	$25,000	$25,000	$155,000
CPUC Bond	$0	$100,000	$0	$0	$0	$100,000
SCE Bond (Phase 1 & 2)	$0	$259,930	$0	$0	$0	$259,930
Total Budget	**$210,780**	**$569,930**	**$200,000**	**$212,938**	**$216,203**	**$1,409,851**

County of Los Angeles

Los Angeles Community Choice Energy

Business Plan Update

April 17, 2017

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Background

On September 15, 2015, the Board of Supervisors ("Board") of the County of Los Angeles ("County") instructed the County's Internal Services Department (ISD) and the Chief Executive Officer (CEO) to assess the feasibility of establishing a Community Choice Aggregation (CCA) for County unincorporated areas, with the potential to expand to other public agencies within the County. The County fulfilled that directive by issuing the County of Los Angeles Community Choice Energy Business Plan ("Business Plan") on July 28, 2016.

On September 27, 2016, the Board directed the CEO, Chief Sustainability Officer, County Counsel, and ISD to form a Joint Powers Authority (JPA) with other interested public agencies, negotiate a governance structure, and determine an operations plan. As part of those negotiations, the CEO requested that the information in the Business Plan be updated to reflect current market prices, regulatory fees, and operational plans to provide potential LACCE JPA member agencies with the most accurate possible assessment of LACCE's financial outlook. This document ("Business Plan Update") details the changed inputs, assumptions, and outcomes.

Updated Findings

- Power supply costs are approximately 21% lower than in the initial business plan due to lower renewable and market price projections.
- It is assumed that LA County provides the initial working capital funding during FY 2018. LA County is then reimbursed by the end of the fiscal year using funds obtained by LACCE once financing has been obtained. This plan does not assume vendor funding; however, it is estimated that cash working capital can be reduced by approximately 50% if LACCE can negotiate a delayed payment contract with power supply vendors (i.e. vendors do not get paid until revenues have been received).
- The residential PCIA increased from $0.00098 to $0.00776 per kWh and is projected to continue to increase in the next few years. Non-residential PCIA rates increased by a similar margin.
- There is no significant cost saving between a 75% residential/65% non-residential participation scenario and a 95% residential/85% non-residential participation scenario because the administrative costs are minor compared to the power supply costs and non-bypassable charges vary based on load.
- Updated projected rates for two scenarios were developed: 75% residential/65% non-residential participation scenario and a 95% residential/85% non-residential participation scenario. The projected rates can be found in the tables below:

Phase-In Assumption

This Business Plan Update assumes LACCE will launch in January 2018 with the same phase-in strategy that was used in the original Business Plan:

- Phase 1 include County-owned facilities within the unincorporated County areas
- Phase 2 serves all customers located in the unincorporated County
- Phase 3 serves all customers within LACCE

Exhibit 1 summarizes the potential load, demand, revenue, and account information for each assumed phase.

Exhibit 1
Participation Schedule

Phase	Start	Eligibility	Customer Accounts	Peak Load (MW)	Average Load aMW	LACCE Annual Revenues
Phase 1	January 2018	LA County Facilities in Unincorporated Area	1,728	40	20	$25M
Phase 2	July 2018	All Unincorporated Customers	306,930	900	440	$180M
Phase 3	To Be Determined	All Customers	1,497,747	7,000	3,000	$1,200M

Depending on the Cities joining LACCE, LACCE may launch a different combination of accounts for Phase 2 such as commercial and industrial accounts operating within the unincorporated County and in any other participating public agencies. Modeling those accounts for this Business Plan Update would have presented two challenges. First, because it remains uncertain which cities will participate in the LACCE JPA, it would be impossible to determine the load, demand, and number of accounts. Second, the specific accounts to include in Phase 2 depends on the total load in LACCE in order to ensure a smooth transition from SCE to LACCE. This Business Plan Update therefore provides an update of LACCE's rates based on the implementation plan listed in Exhibit 1.

Load Forecast

This business plan assumes launch in January 2018. The load forecast was updated to reflect projected loads and participation rates. This Business Plan Update models two CCA participation scenarios. The first scenario ("Conservative Participation Scenario") modeled participation rates of 75 percent for residential customers and 65 percent for non-residential customers. The second scenario ("Most Likely Participation Scenario") assumed 95% participation for residential customers and 85% for non-residential customers which is based on the average participation of all currently operating CCAs in California.

SCE Rate Forecast

Southern California Edison's (SCE) rates are updated based on the January 1, 2017 posted rates. In addition, the Power Charge Indifference Adjustment (PCIA) is also updated as of January 1, 2017. An updated PCIA forecast was also developed to reflect expected changes in renewable resource benchmarking costs. Exhibit 2 shows the updated PCIA rate forecast used.

Exhibit 2 PCIA Rates by Rate Class and Year					
	Actual		Forecast		
	2016	2017	2018	2019	2020
Domestic	0.00098	0.00776	0.01009	0.01160	0.01117
TC-1	0.00048	0.00348	0.00452	0.00520	0.00501
TOU-GS-1	0.00071	0.00635	0.00826	0.00949	0.00914
TOU-GS-2	0.00079	0.00590	0.00767	0.00882	0.00850
TOU-GS-3	0.00070	0.00524	0.00681	0.00783	0.00754
TOU-PA-2	0.00055	0.00533	0.00693	0.00797	0.00767
TOU-PA-3	0.00042	0.00399	0.00519	0.00597	0.00575
TOU-8-PRI	0.00061	0.00395	0.00514	0.00591	0.00569
TOU-8-SEC	0.00052	0.00457	0.00594	0.00683	0.00658
TOU-8-SUB	0.00045	0.00339	0.00441	0.00507	0.00488

In addition to the PCIA, SCE's generation and distribution rates were updated for each rate class.

Power Supply

The forecast cost of power was updated to reflect the most recent trends in the power market. Natural gas-fired power plants define the base power price in southern California and throughout the Western Energy Coordinating Council (WECC) footprint as they serve as the marginal resource. As the market price of electricity is usually set by the cost of the marginal unit, EES developed a wholesale market price forecast using a forecast of natural gas prices and projected market-implied heat rates or spark spreads.

The projected market-implied heat rates reflect the average efficiency of gas-fired power plants in California. The projected heat rates are based on historic market-implied heat rates calculated by dividing historic southern California (SP15) wholesale market prices by historic southern California natural gas prices. EES developed a natural gas price forecast based on NYMEX forward gas prices for the Henry Hub trading hub and southern California basis differentials. Projected market heat rates were then applied to the southern California natural gas price forecast to calculate a wholesale electric market price forecast for southern California.

The following steps were taken to produce the wholesale electric market price forecast:

1. Forward prices for natural gas at Henry Hub are available through December 2029.
2. The southern California basis differential is used to adjust the Henry Hub forward prices to southern California prices. Southern California forward natural gas prices are equal to NYMEX forward prices (Henry Hub) plus the southern California basis. The southern California basis forward curve is available through December 2022. After December 2022, the monthly southern California basis differentials are assumed to escalate at the same escalation rate at which Henry Hub forward prices escalate or near 2.3 percent on average.
3. Projected monthly market-implied heat rates are multiplied by forecast southern California natural gas prices to calculate forecast southern California wholesale market prices.
4. Projected heat rates are based on historic heat rates (southern California wholesale electricity prices divided by SoCal natural gas prices).

5. Monthly market-implied heat rates are held constant in all years.
6. Forecast southern California prices are benchmarked against other market price forecasts.
7. Forecast market prices are escalated 3.8 percent annually beginning in 2030.

Based on the methodology detailed above, southern California wholesale market prices are projected to escalate annually at an average rate of 3.3 percent over the 20-year period from 2018 through 2037.

Exhibit 3 below shows the forecast southern California natural gas prices included in the calculation of forecast southern California market prices. **Projected 2018-25 gas prices are approximately 21 percent lower than those included in the first draft of the business plan**.

Exhibit 3
Forecast SoCal Natural Gas Price ($/MMBtu)

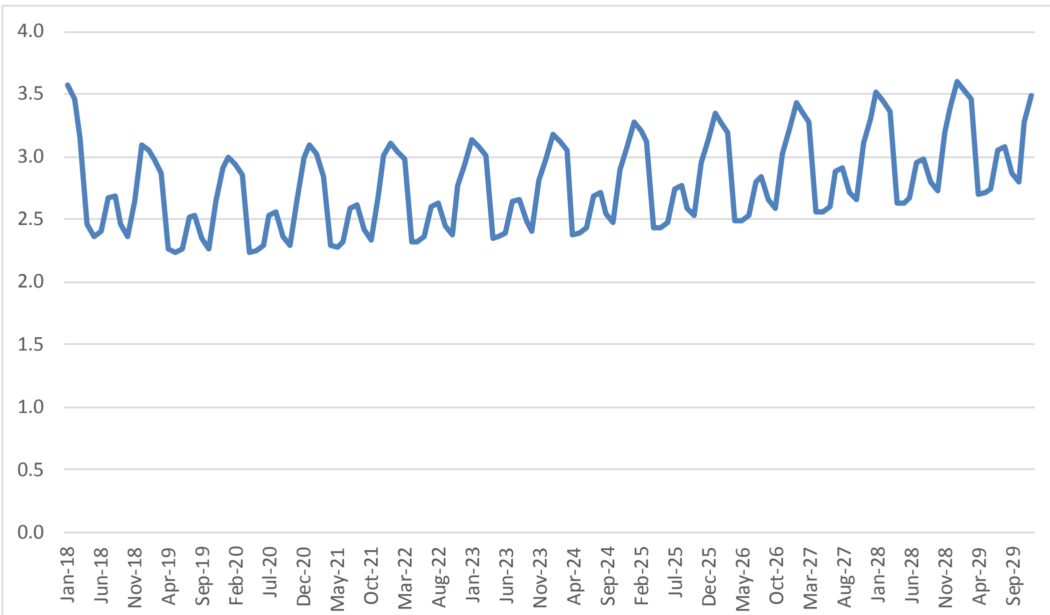
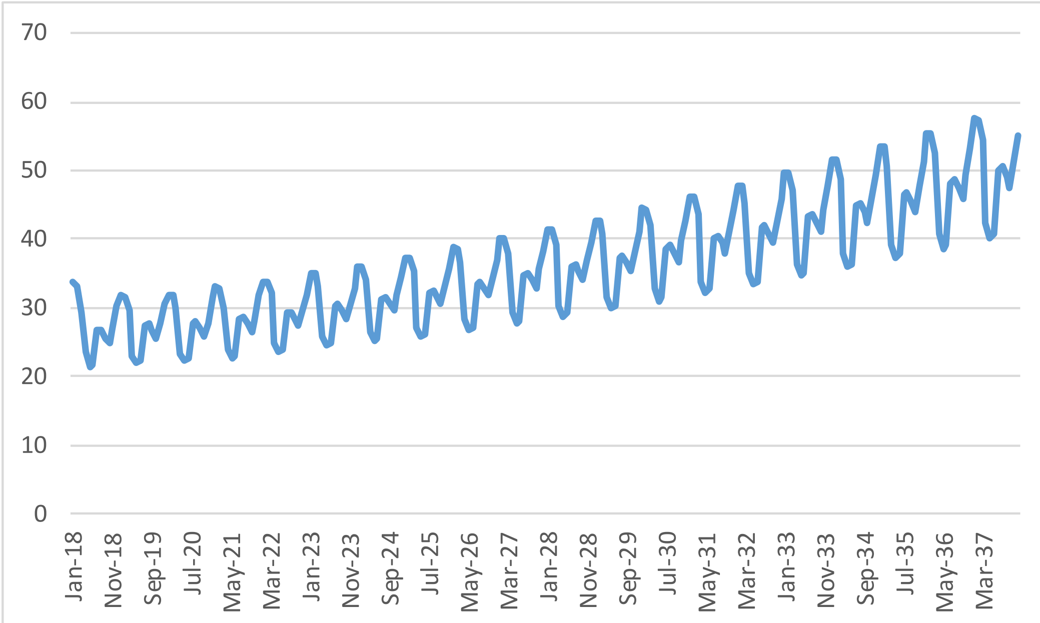


Exhibit 4 shows the resulting monthly southern California wholesale market price forecast. The levelized value of market prices over the study period is $34.6/MWh assuming a 4 percent discount rate. This is **a decrease of nearly $5/MWh and 12 percent from the levelized value of $39.5/MWh included in the first draft of the business plan**.

Exhibit 4
Forecast Southern California Wholesale Market Prices ($/MWh)



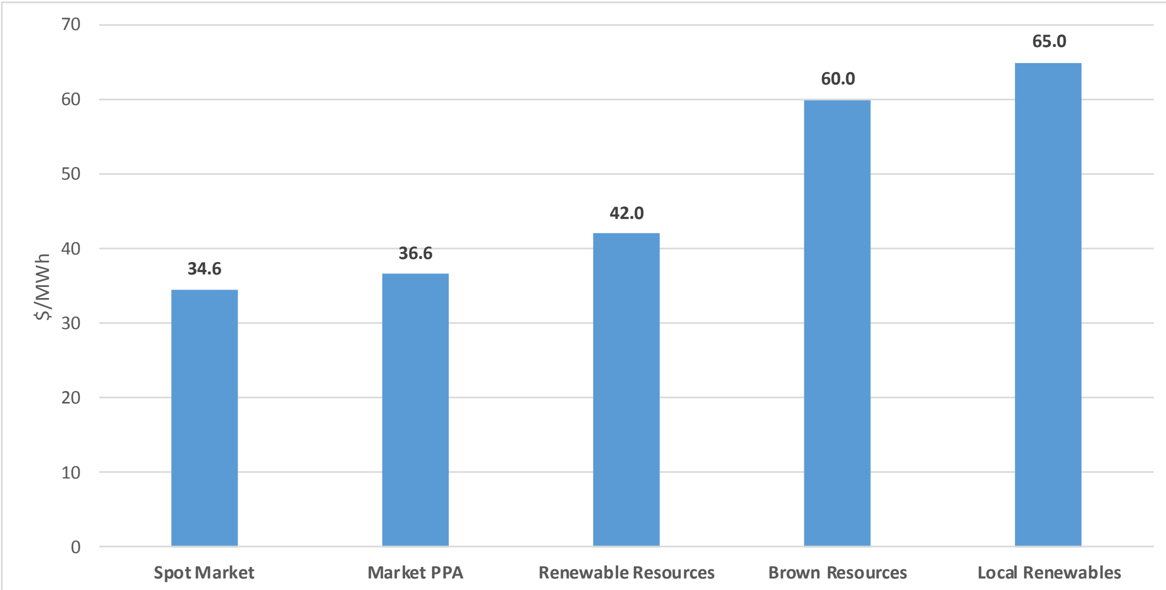
Wholesale power prices were used to calculate balancing market purchases and sales. When the LACCA's loads are greater than its resource capabilities, the LACCA's scheduling agent will schedule balancing purchases and the LACCA will incur balancing market purchase costs. When the LACCA's loads are less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

Exhibit 5 shows the 20-year levelized resource costs included in the study. In the first draft of the business plan the "spot market" and "market PPA" costs were $39.5/MWh and $41.5/MWh, respectively, or 12 percent greater than those shown below. The costs shown below for "renewable resource", "brown resources" and "local renewables" are the same as those included in the first draft of the business plan.

Energy Efficiency, Demand Response, and Distributed Energy Resources

The power supply forecast does not account for the extensive investment in local conservation and resource programs that LACCE will make. This assumption was employed because of the uncertainty around the timeframe, type, and scale of the programs that LACCE will deploy as these must be voted on by the JPA board. However, these programs are expected to be extensive.

Exhibit 5
20-Year Levelized Cost
(2017 $/MWH)



Updated Resource Portfolios

An updated load forecast was input to the power supply cost calculations. As a result, the resource portfolios and associated costs were updated. Below is a summary of the revised portfolios. There was no change to the amount of renewable and non-renewable resource targets, only a change in the amount of energy required to achieve those targets due to the change in the load forecast.

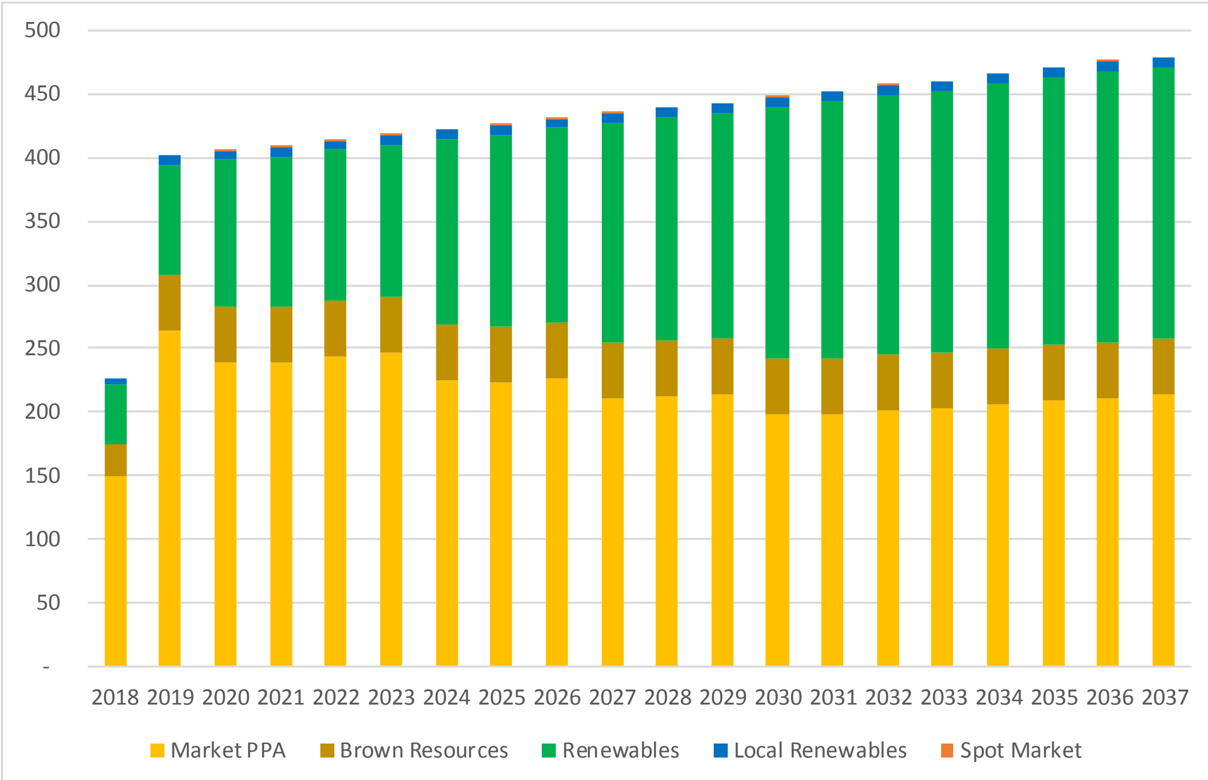
Portfolio 1: Meet Current RPS Requirements

In the first portfolio, the CCA would meet the state RPS requirements shown below:

- 2017-19: 25 percent
- 2020-23: 33 percent
- 2024-26: 40 percent
- 2027-29: 45 percent
- 2030 - 50 percent

Exhibit 6 shows the power supply portfolio used to serve load in Portfolio 1 with the revised load forecast. In the first draft of the business plan total purchased power requirements were 436 aMW in final year of the 20-year study period compared to the 479 aMW shown below in 2037.

Exhibit 6
Portfolio 1: Meet RPS Requirements (aMW)

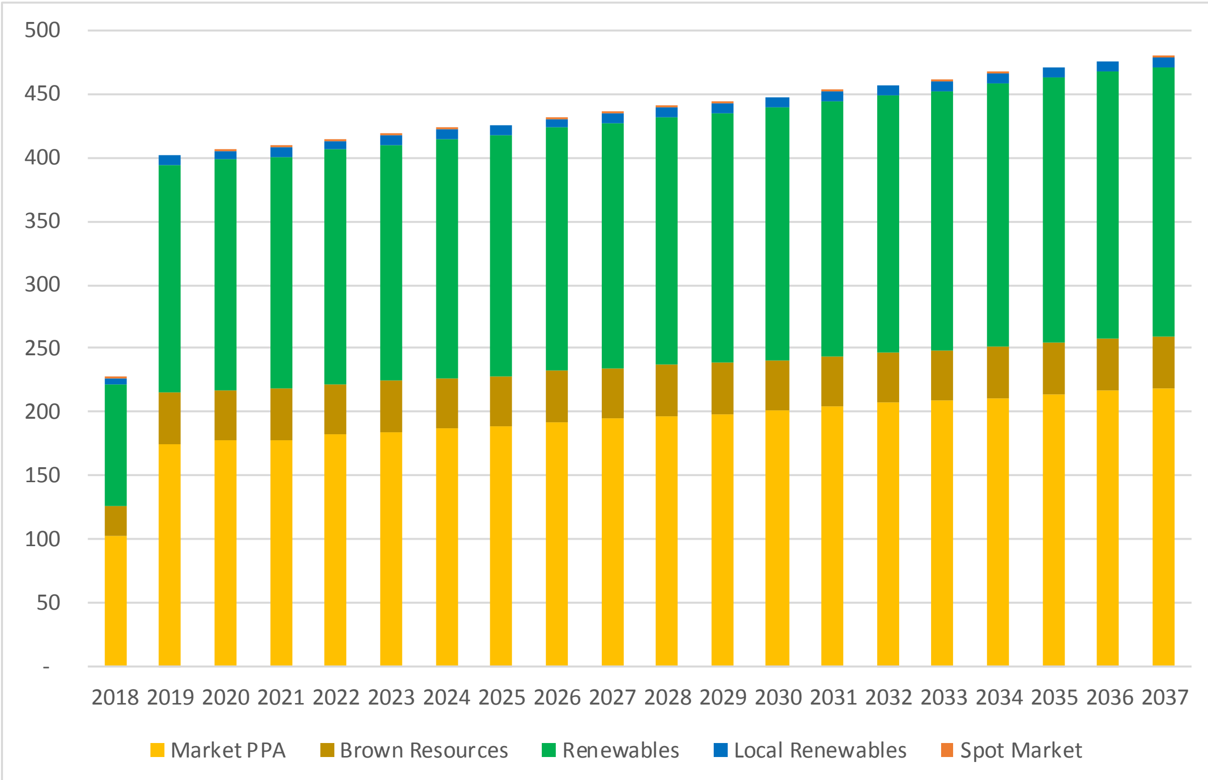


The green bars shown in Exhibit 6 above increase each year along with California's RPS requirements.

Portfolio 2: Serve 50% of Retail Load with Renewables Starting on Day 1

In this portfolio, the 50% renewable energy purchase requirement in the RPS is effectively moved up from 2030 to October 2016. Exhibit 7 shows the breakdown of power purchases under portfolio 2 with the revised load forecast. The total power purchase requirements are the same as those shown above in Exhibit 6, including a total purchase requirement of 479 aMW in 2037.

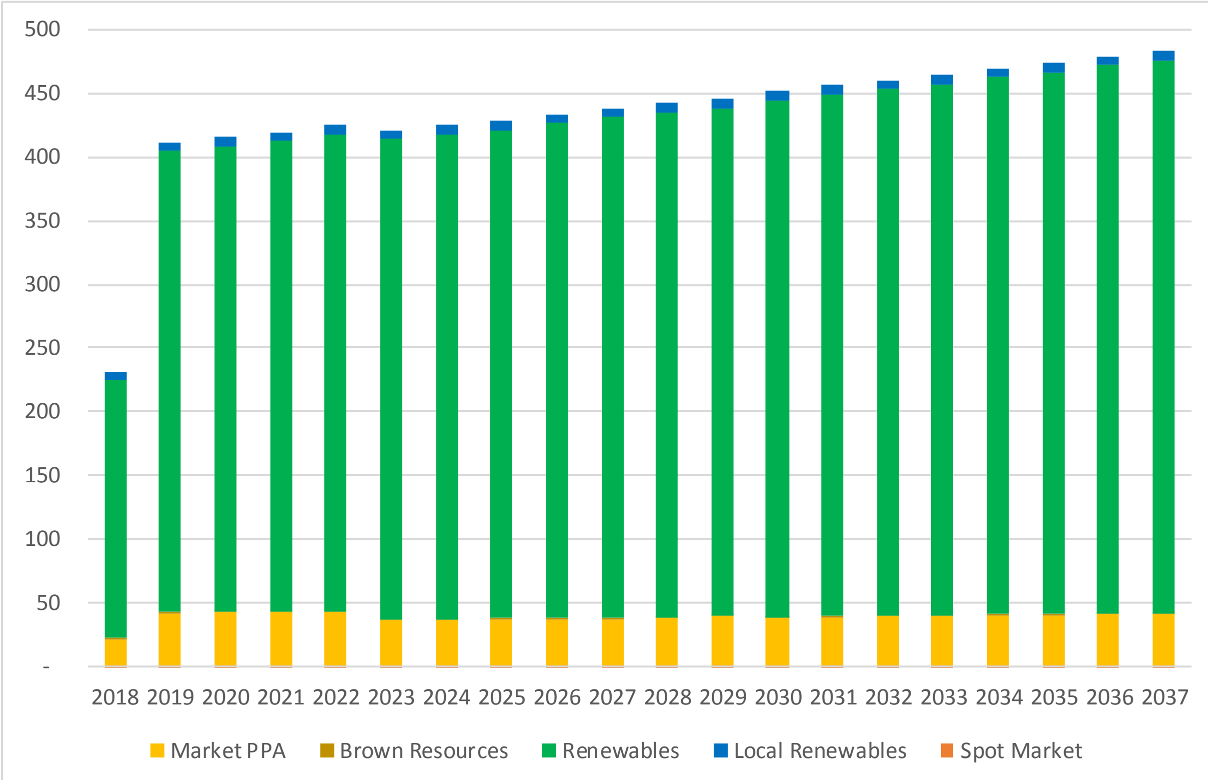
Exhibit 7
Portfolio 2: Serve 50% of Retail Load with Renewables (aMW)



Portfolio 3: Serve 100% of Retail Load with Renewables Starting on Day 1

In this portfolio retail loads are served entirely with renewable energy purchases. Exhibit 8 below shows the resource mix used to serve load in Portfolio 3 with the revised load forecast. The total power purchase requirements are the same as those shown above in Exhibits 6 and 7, including a total purchase requirement of 479 aMW in 2037.

Exhibit 8
Portfolio 3: Serve 100% of Retail Load with Renewables (aMW)

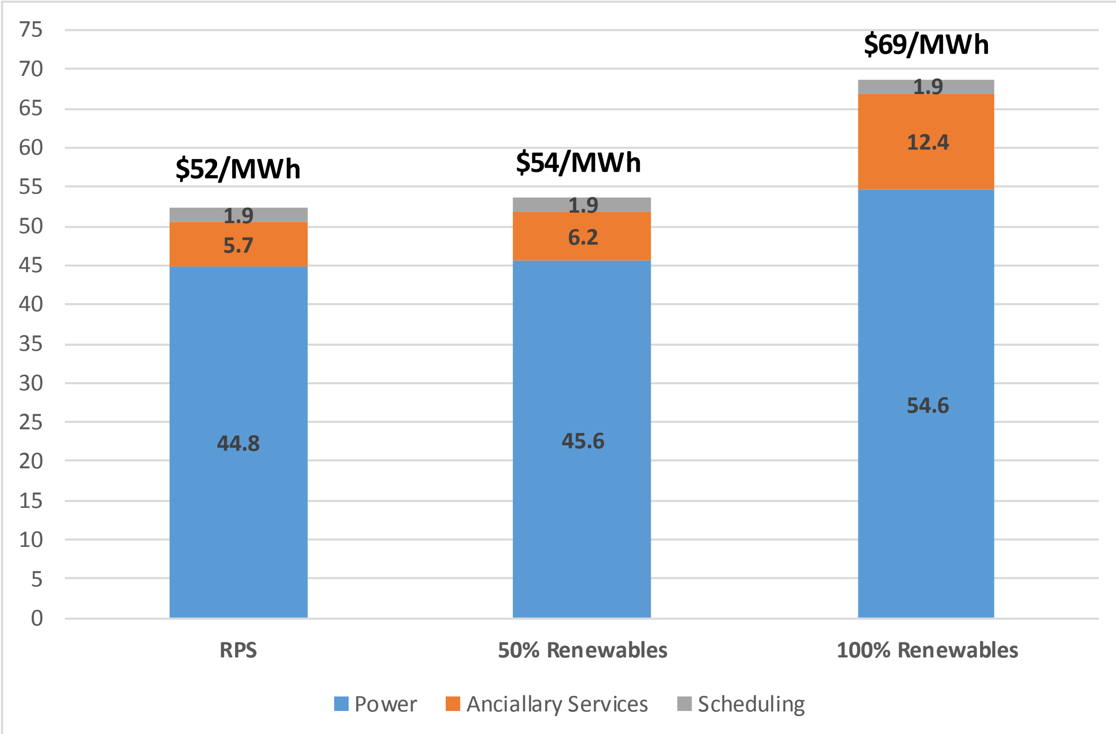


As shown above, there is a small amount of market PPA and brown resource power included in Portfolio 3 due to distribution and transmission system losses. The renewable energy requirements in the state's RPS are based on retail energy sales. To be consistent it was assumed that the 100% renewable energy target would only apply to retail energy sales, not total power purchase requirements.

20-Year Levelized Portfolio Costs

20-year levelized costs were calculated for the three resource portfolios described above using base case resource costs and the revised load forecast. Exhibit 9 below shows a breakdown of power, ancillary service and scheduling costs associated with each portfolio.

Exhibit 9
20-year Levelized Base Case Portfolio Costs ($/MWh)



The 20-year levelized cost shown above for portfolio 1 ("RPS") is $2/MWh less than the cost included in the first draft of the business plan. The 20-year levelized cost shown above for portfolio 2 ("50% Renewables") is $1/MWh less than the cost included in the first draft of the business plan. The 20-year levelized cost shown above for portfolio 3 ("100% Renewables") is $1/MWh greater than the cost included in the first draft of the business plan.

Since wholesale market prices decreased in the revised power supply cost calculations one would expect the 20-year levelized costs shown above to have decreased in all cases, including the "100% Renewables" case, compared to the first draft of the business plan. Power purchase costs, excluding capacity purchase costs, did in fact decrease in all cases. However, capacity purchase costs increased in all cases due to a reduction in the average monthly load factor in the revised load forecast. Monthly load factors are calculated by dividing average monthly energy consumption by monthly peak demands. The average monthly load factor in the revised load forecast is 56 percent. The average monthly load factor in the load forecast used in the first draft of the business plan was 66 percent. The decrease in the average monthly load factor result in higher monthly peak demands. Increased monthly peak demands result in increases in capacity purchase costs associated with meeting the 115 percent resource adequacy standard. On a 20-year levelized cost basis the capacity purchase costs associated with meeting resource adequacy requirements increased by near $1.5/MWh in all three portfolios.

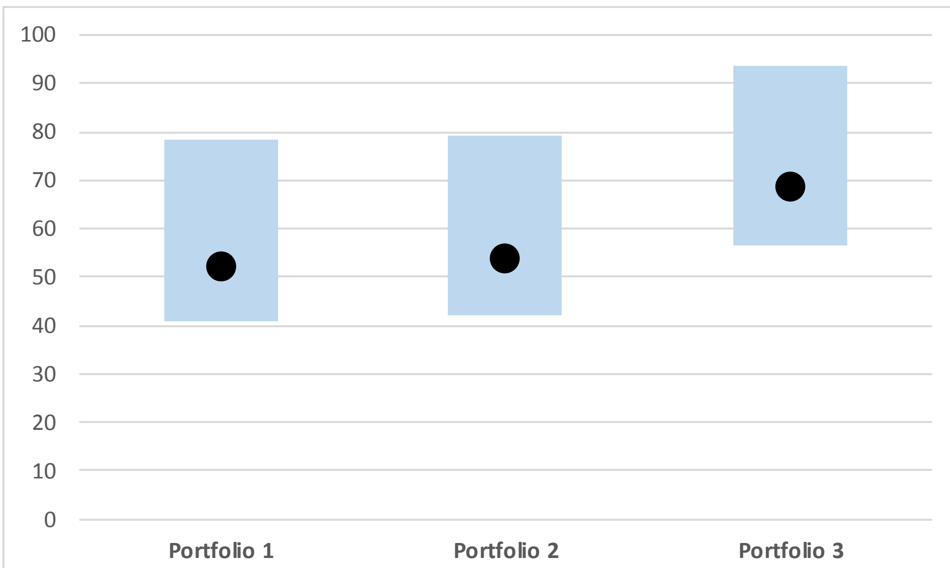
Exhibit 9 above shows the base case 20-year levelized cost of each portfolio. Since resource costs are based on forecast renewable and brown resource market prices and updated forecast natural gas and wholesale market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculation to fluctuations in these projections. Exhibit 10 below shows a summary of low, base and high resource costs. Only the "market PPA" costs differ from the first draft of the business plan.

Exhibit 10
Low, Base and High 20-year Levelized Resource Costs ($/MWh)

Case	Market PPA	Portfolio 1 and 2 Renewables	Portfolio 3 Renewables	Brown Resources	Local Renewables
Low Case	24.9	32	40	45	45
Base Case	36.6	42	52	60	65
High Case	69.2	62	76	80	85

The 20-year levelized costs of each portfolio were calculated using the range of resource costs shown above. Exhibit 11 shows the resulting range of 20-year levelized costs of each resource portfolio. The base case costs are depicted by the black dots in Exhibit 11.

Exhibit 11
Sensitivity of Portfolio 20-year Levelized Costs



The range of costs shown above is slightly ($1/MWh) greater than the range of costs included in the first draft of the business plan. As in the first draft of the business plan, Portfolio 3, which relies on renewable energy purchases to serve all retail loads, has the highest projected costs. The low case for Portfolio 3 ($57/MWh) is greater than the base case for both Portfolios 2 and 3.

Proforma Analysis

The first category of the pro forma analysis is the cost of service for LACCE program operations. To estimate the overall costs associated with LACCE operations, the following components were included in the development of the financial pro forma:

- Power Supply Costs
- Non-Power Supply Costs:
  - Start-up costs
  - LACCE staffing and administration costs
  - Consulting Support
  - SCE and regulatory charges
  - Financing costs
- Pass-Through Charges to SCE:
  - Transmission and distribution charges
  - Power Cost Indifference Adjustment (PICA) Charge
  - Other SCE non-bypassable charges

Once the costs of the LACCE operations have been determined, the total costs and resulting revenue needs were compared to SCE's projected rates and revenues for the potential LACCE customers.

Administrative Costs

The administrative costs were updated based on the most recent LACCE budget. At this time, it is assumed that $10 million in initial funding will be provided by LA County as part of the FY2018 budget to support the start-up of the LACCE Authority. This funding includes $8 million for power procurement to support Phase I of the program and up to $2 million for administrative costs.

In addition to administrative costs, expenses such as power supply costs, non-bypassable charges, data management costs, utility fees, and estimated uncollectibles are included in the proforma. The LACCE budget assumes only the Executive Director and one administrative staff will be hired prior to Phase 2 as LACCE will rely on consultant help initially. However, LACCE could hire additional staff earlier and reduce the cost of consultants to remain within budget. Exhibit 12 lists the assumed expenses.

Exhibit 12 Administrative Costs		
	FY17	FY18
EXPENSES		
Consultants		
Financial	$30,000	$120,000
Legal	$0	$200,000
Executive Support	$50,000	$180,000
Technical & Regulatory	$40,000	$460,000
Communication & Outreach	$0	$80,000
County Staff (borrowed)		
Chief Sustainability Officer	$20,000	$40,000
ISD Staff	$40,000	$80,000
County Counsel	$30,000	$30,000
Administrative Support	$10,000	$20,000
New JPA Staff		
Executive Director	$0	$150,000
Assistant	$0	$50,000
General & Admin	$0	$295,000
Contingency	$0	$50,000
Budgeted Expenses Off-set	($220,000)	($630,000)
Total Administrative Cost	**$0**	**$1,125,000**

Financing

The $10 million provided by LA County as part of the FY2018 budget will need to be repaid to LA County by the end of June 2018. For ongoing cash flow needs, this Business Plan Update assumes that LACCE must provide sufficient working capital to cover 60 days of lag between when expenses occur and when revenues are received. LACCE will therefore need to finance approximately $50 million by June 2018 either with a loan or a line of credit. A more likely scenario, would be that the power supply and data management consultants will not get paid until revenues have been collected from customers. This methodology has become more common with recent CCAs and would reduce LACCE's financing needs by approximately 50%. This option will be explored during the RFP process for power supply and data management services.

Rates

Exhibits 13 and 14 compare the revised LACCE rates with those of the comparable SCE product for each rate class under the Conservative Participation Scenario and the Most Likely Participation Scenario.

Exhibit 13 Conservative Scenario – Bundled Rates							
Rate Class	**Customer Type**	**SCE Basic***	**LACCE RPS**	**SCE 50% Renewable**	**LACCE 50% Renewable**	**SCE 100% Renewable**	**LACCE 100% Renewable**
Residential	Domestic	17.2	**16.3**	18.9	**16.5**	20.7	**18.3**
GS-1	Commercial	16.6	**15.7**	18.2	**15.9**	19.8	**17.7**
GS-2	Commercial	15.7	**14.9**	17.8	**15.1**	19.8	**16.7**
GS-3	Industrial	14.2	**13.4**	16.5	**13.6**	18.7	**15.1**
PA-2	Public Authority	12.4	**11.7**	14.6	**11.9**	16.7	**13.2**
PA-3	Public Authority	10.8	**10.2**	13.6	**10.4**	16.3	**11.5**
TOU-8 Secondary	Commercial	12.6	**11.9**	14.9	**12.1**	17.1	**13.4**
TOU-8 Primary	Commercial	11.5	**10.9**	13.9	**11.0**	16.2	**12.2**
TOU-8 Substation	Industrial	7.5	**7.1**	10.3	**7.2**	13.2	**8.0**
LACCE Savings vs. SCE Basic			5.3%		4.1%		-6.3%
LACCE Savings vs. SCE Equivalent			5.3%		-13.7%		-12.9%

*SCE bundled average rate based on Table 3 in Advice 3515-E-A.

Exhibit 14 Most Likely Scenario – Bundled Rates							
Rate Class	**Customer Type**	**SCE Basic***	**LACCE RPS**	**SCE 50% Renewable**	**LACCE 50% Renewable**	**SCE 100% Renewable**	**LACCE 100% Renewable**
Residential	Domestic	17.2	**16.3**	18.9	**16.5**	20.7	**18.3**
GS-1	Commercial	16.6	**15.7**	18.2	**15.9**	19.8	**17.6**
GS-2	Commercial	15.7	**14.9**	17.8	**15.0**	19.8	**16.7**
GS-3	Industrial	14.2	**13.4**	16.5	**13.6**	18.7	**15.1**
PA-2	Public Authority	12.4	**11.7**	14.6	**11.9**	16.7	**13.2**
PA-3	Public Authority	10.8	**10.2**	13.6	**10.3**	16.3	**11.5**
TOU-8 Secondary	Domestic	12.6	**11.9**	14.9	**12.1**	17.1	**13.4**
TOU-8 Primary	Commercial	11.5	**10.9**	13.9	**11.0**	16.2	**12.2**
TOU-8 Substation	Industrial	7.5	**7.1**	10.3	**7.2**	13.2	**8.0**
LACCE Savings vs. SCE Basic			5.3%		4.2%		-6.3%
LACCE Savings vs. SCE Equivalent			5.3%		-13.7%		-13.0%

*SCE bundled average rate based on Table 3 in Advice 3515-E-A.

LACCE customers are likely to see rates that on average are 5.3% lower than SCE in the portfolio meeting RPS standards, 4.1% to 4.2% lower than SCE with 50% renewable power supply and 6.3% higher than SCE with 100% renewable power supply.

Risks

The results of this Business Plan Update are subject to uncertainties. The list below provides a summary discussion of the key uncertainties of this Plan. These have not changed since the Initial Business Plan. A comparative table of risks to CCA viability is also provided in Exhibit 15.

- *Market Price Forecasts* – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this Plan are based on the best currently available information regarding future natural gas and electricity prices, and have been confirmed by recent wholesale power transactions in southern California. However, these types of forecasts vary over time.
- *Retail Rate Forecasts* – The Plan forecasts retail rates for both LACCE and SCE over the study period. These forecasts are based on current information regarding inflation, RPS requirement and other cost drivers.
- *Forecast Load and Customer Growth* – The Plan bases the load forecasts on customer growth and participation. Both variables are inherently uncertainty.
- *Regulatory Risks* – Unforeseen changes in legislation (California Public Utility Commission, state legislation and federal legislation) may impact the results of this Plan.

This sensitivity analysis from the initial Business Plan show that the LACCE rates could be greater than SCE rates if:

- The Power Charge Indifference Adjustment (PCIA) increases significantly without an offsetting power supply cost reduction.
- LACCE loads are much less than forecast. For example, if LACCE only achieves Phase 1 participation, it would be difficult to operate LACCE at lower rates than SCE.
- Wholesale market prices drop to 25% lower than present levels. As power costs to both SCE and LACCE are decreased, the PCIA would increase. This causes additional risks to LACCE even though power procurement costs could be lower.

Each of these three scenarios can be managed if they occur (see Exhibit 15). LACCE can mitigate risk from PCIA increases or from wholesale market price drops by investing in a power portfolio that is balanced between long and short-term contracts and by maintaining a healthy reserve fund to cushion rates through periods of high PCIA rates (as Marin Clean Energy and Sonoma Clean Power have done repeatedly). If LACCE's load becomes significantly lower than expected due to poor customer participation, LACCE could expand its service territory, merge with another existing CCA, or reduce overhead expenses.

In the long-term, the PCIA is expected to decline as contracts expire and market prices increase. In addition, SCE is now taking into account the potential loss of load to CCAs and is not purchasing purchase power on behalf of CCA customers, thus not incurring additional stranded costs on behalf of CCA customers.

Finally, the extremely low levels of participation needed to undermine the financial viability of LACCE is extremely unlikely given the increasing precedent set by other CCAs in California and their success in retaining customers. The results of this update demonstrate that there is sufficient load in LA County such that participation as low as 75% residential and 65% non-residential will not have an impact of the feasibility of LACCE.

Exhibit 15
Comparison of Risks, Mitigation Strategies, and Risk Severity

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

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

Summary

This updated Business Plan supports the initial findings that the formation of a CCA in Los Angeles County is financially viable and will yield considerable benefits for the County's residents and businesses. These benefits include competitive rates for electricity and increased renewable resource deployment. With the achievement of Phase 2 operations, LACCE could reduce GHG emissions by as much as 500,000 tons of CO_2e per year, add hundreds of jobs, generate over $24 million in additional GDP, and give the County and its residents local control over their power supply and distributed energy resource programs.

LA County Community Choice Aggregation
Financial Operating Model - RPS
Most Likely Load Scenario
April 17, 2017

CCE Operating Costs	**2018 Jan - June**	**2018 July - Dec**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Power Supply	$3,686,331	$65,790,271	$124,402,952	$131,084,972	$135,206,213	$139,311,119	$143,876,267	$149,939,112	$154,456,310	$159,160,232	$164,565,198	$169,481,295
Billing & Data Management	$12,960	$2,377,248	$4,770,904	$4,815,913	$4,881,173	$4,956,358	$5,057,834	$5,169,415	$5,285,118	$5,408,747	$5,526,017	$5,614,925
SCE Fees	$1,132,892	$1,992,059	$1,564,964	$1,579,727	$1,601,133	$1,625,793	$1,659,077	$1,695,676	$1,733,627	$1,774,177	$1,812,641	$1,841,803
Technical Services	$665,000	$665,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000
Staffing	$200,000	$935,000	$2,825,400	$2,881,908	$2,939,546	$2,998,337	$3,058,304	$3,119,470	$3,181,859	$3,245,496	$3,310,406	$3,376,615
General & Administrative expenses	$170,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698
Contribution to Annual Reserves	$0	$12,500,132	$11,859,731	$14,211,596	$17,222,458	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$17,222,458	$19,006,515	$19,731,020	$20,345,034	$21,016,655	$21,697,061	$22,392,359
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,091,983	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital	($5,795,079)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$35,238	$475,734	$917,272	$952,220	$973,452	$994,659	$936,132	$965,433	$988,371	$1,012,191	$1,039,157	$1,063,956
Total Operating Costs	$107,341	$87,057,427	$152,181,191	$161,322,422	$168,626,304	$172,917,420	$179,409,321	$186,441,940	$191,818,892	$197,452,963	$203,792,975	$209,620,618
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$107,341	$87,057,427	$152,181,191	$161,322,422	$168,626,304	$172,917,420	$179,409,321	$186,441,940	$191,818,892	$197,452,963	$203,792,975	$209,620,618
Average CCE Rate ($/kWh)		$0.0304	$0.0525	$0.0551	$0.0570	$0.0579	$0.0595	$0.0612	$0.0623	$0.0635	$0.0649	#DIV/0!
Average SCE Generation Rate ($/kWh)		$0.0708	$0.0721	$0.0748	$0.0763	$0.0777	$0.0794	$0.0816	$0.0831	$0.0847	$0.0866	$0.0882
Total CCE Charges												
SCE Non-bypassable Charges	$1,180,317	$21,065,221	$44,050,294	$44,285,334	$44,260,075	$44,231,547	$27,759,816	$27,341,146	$27,188,763	$27,014,003	$26,774,656	$26,626,898
CCE Revenue Requirement	$107,341	$87,057,427	$152,181,191	$161,322,422	$168,626,304	$172,917,420	$179,409,321	$186,441,940	$191,818,892	$197,452,963	$203,792,975	$209,620,618
Total CCE Generation Revenue Requirement	$1,287,658	$108,122,649	$196,231,485	$205,607,756	$212,886,379	$217,148,968	$207,169,137	$213,783,086	$219,007,655	$224,466,965	$230,567,631	$236,247,516
Bundled SCE Revenues	$14,645,671	$261,382,583	$496,123,003	$514,635,004	$530,143,564	$545,933,115	$562,626,036	$581,567,457	$598,848,517	$616,709,587	$635,822,737	$654,666,595
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$13,850,089	$247,183,773	$469,547,565	$487,496,287	$503,609,432	$518,760,617	$533,501,486	$549,838,302	$565,250,803	$581,155,157	$598,022,149	$614,853,993
Savings	**$795,581**	**$14,198,811**	**$26,575,439**	**$27,138,717**	**$26,534,132**	**$27,172,498**	**$29,124,550**	**$31,729,155**	**$33,597,715**	**$35,554,430**	**$37,800,588**	**$39,812,601**
Percent Savings	**5.4%**	**5.4%**	**5.4%**	**5.3%**	**5.0%**	**5.0%**	**5.2%**	**5.5%**	**5.6%**	**5.8%**	**5.9%**	**6.1%**

LA County Community Choice Aggregation
Financial Operating Model - 50%
Most Likely Load Scenario
April 17, 2017

CCE Operating Costs	2018 Jan - June	2018 July - Dec	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Power Supply	$4,015,169	$71,659,076	$135,183,802	$138,693,462	$142,388,025	$146,043,916	$150,140,651	$154,233,188	$158,395,613	$162,795,708	$167,274,678	$171,908,752
Billing & Data Management	$12,960	$2,377,248	$4,770,904	$4,815,913	$4,881,173	$4,956,358	$5,057,834	$5,169,415	$5,285,118	$5,408,747	$5,526,017	$5,614,925
SCE Fees	$1,132,892	$1,992,059	$1,564,964	$1,579,727	$1,601,133	$1,625,793	$1,659,077	$1,695,676	$1,733,627	$1,774,177	$1,812,641	$1,841,803
Technical Services	$665,000	$665,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000
Staffing	$200,000	$935,000	$2,825,400	$2,881,908	$2,939,546	$2,998,337	$3,058,304	$3,119,470	$3,181,859	$3,245,496	$3,310,406	$3,376,615
General & Administrative expenses	$170,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698
Contribution to Annual Reserves	$0	$10,312,252	$6,822,356	$12,202,675	$15,588,389	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$15,588,389	$16,837,461	$18,175,678	$20,952,012	$22,123,195	$23,257,445	$25,050,601
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,091,983	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital	($5,795,079)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$36,882	$505,078	$971,177	$990,262	$1,009,361	$1,028,323	$967,454	$986,904	$1,008,068	$1,030,368	$1,052,704	$1,076,093
Total Operating Costs	$437,824	$90,767,696	$157,978,570	$166,960,034	$174,209,956	$178,049,813	$183,535,972	$189,202,146	$196,384,870	$202,213,156	$208,076,386	$214,718,454
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$437,824	$90,767,696	$157,978,570	$166,960,034	$174,209,956	$178,049,813	$183,535,972	$189,202,146	$196,384,870	$202,213,156	$208,076,386	$214,718,454
Average CCE Rate ($/kWh)		$0.0318	$0.0545	$0.0570	$0.0589	$0.0596	$0.0608	$0.0621	$0.0638	$0.0651	$0.0663	#DIV/0!
Average SCE Generation Rate ($/kWh)		$0.0708	$0.0721	$0.0748	$0.0763	$0.0777	$0.0794	$0.0816	$0.0831	$0.0847	$0.0866	$0.0882
Total CCE Charges												
SCE Non-bypassable Charges	$1,180,317	$21,065,221	$44,050,294	$44,285,334	$44,260,075	$44,231,547	$27,759,816	$27,341,146	$27,188,763	$27,014,003	$26,774,656	$26,626,898
CCE Revenue Requirement	$437,824	$90,767,696	$157,978,570	$166,960,034	$174,209,956	$178,049,813	$183,535,972	$189,202,146	$196,384,870	$202,213,156	$208,076,386	$214,718,454
Total CCE Generation Revenue Requirement	$1,618,141	$111,832,917	$202,028,863	$211,245,367	$218,470,032	$222,281,360	$211,295,788	$216,543,292	$223,573,633	$229,227,158	$234,851,042	$241,345,352
Bundled SCE Revenues	$14,645,671	$261,382,583	$496,123,003	$514,635,004	$530,143,564	$545,933,115	$562,626,036	$581,567,457	$598,848,517	$616,709,587	$635,822,737	$654,666,595
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$14,064,486	$251,010,127	$475,344,943	$493,133,898	$509,193,084	$523,358,025	$538,241,850	$554,760,827	$570,316,343	$586,369,193	$603,403,419	$620,390,618
Savings	**$581,185**	**$10,372,456**	**$20,778,060**	**$21,501,106**	**$20,950,479**	**$22,575,091**	**$24,384,186**	**$26,806,630**	**$28,532,175**	**$30,340,394**	**$32,419,318**	**$34,275,976**
Percent Savings	**4.0%**	**4.0%**	**4.2%**	**4.2%**	**4.0%**	**4.1%**	**4.3%**	**4.6%**	**4.8%**	**4.9%**	**5.1%**	**5.2%**

LA County Community Choice Aggregation
Financial Operating Model - 100%
Most Likely Load Scenario
April 17, 2017

CCE Operating Costs	**2018 Jan - June**	**2018 July - Dec**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Power Supply	$5,548,178	$99,018,830	$186,079,876	$188,636,541	$192,678,974	$196,031,746	$199,572,470	$203,167,022	$206,716,119	$210,557,028	$214,410,606	$218,369,553
Billing & Data Management	$12,960	$2,377,248	$4,770,904	$4,815,913	$4,881,173	$4,956,358	$5,057,834	$5,169,415	$5,285,118	$5,408,747	$5,526,017	$5,614,925
SCE Fees	$1,132,892	$1,992,059	$1,564,964	$1,579,727	$1,601,133	$1,625,793	$1,659,077	$1,695,676	$1,733,627	$1,774,177	$1,812,641	$1,841,803
Technical Services	$665,000	$665,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000
Staffing	$200,000	$935,000	$2,825,400	$2,881,908	$2,939,546	$2,998,337	$3,058,304	$3,119,470	$3,181,859	$3,245,496	$3,310,406	$3,376,615
General & Administrative expenses	$170,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698
Contribution to Annual Reserves	$0	$8,983,030	$7,434,112	$18,385,996	$20,882,509	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$20,882,509	$24,067,283	$27,751,248	$33,305,073	$36,880,335	$40,432,768	$44,944,873
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,091,983	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital	($5,795,079)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$44,547	$641,877	$1,225,657	$1,239,978	$1,260,816	$1,278,262	$1,214,613	$1,231,573	$1,249,670	$1,269,175	$1,288,384	$1,308,397
Total Operating Costs	$1,978,498	$116,935,027	$209,740,879	$223,336,149	$230,046,480	$233,581,703	$240,444,772	$247,956,219	$257,300,039	$264,970,422	$272,623,317	$281,305,832
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	$1,978,498	$116,935,027	$209,740,879	$223,336,149	$230,046,480	$233,581,703	$240,444,772	$247,956,219	$257,300,039	$264,970,422	$272,623,317	$281,305,832
Average CCE Rate ($/kWh)		$0.0414	$0.0724	$0.0763	$0.0778	$0.0782	$0.0797	$0.0814	$0.0836	$0.0853	$0.0868	#DIV/0!
Average SCE Generation Rate ($/kWh)		$0.0708	$0.0721	$0.0748	$0.0763	$0.0777	$0.0794	$0.0816	$0.0831	$0.0847	$0.0866	$0.0882
Total CCE Charges												
SCE Non-bypassable Charges	$1,180,317	$21,065,221	$44,050,294	$44,285,334	$44,260,075	$44,231,547	$27,759,816	$27,341,146	$27,188,763	$27,014,003	$26,774,656	$26,626,898
CCE Revenue Requirement	$1,978,498	$116,935,027	$209,740,879	$223,336,149	$230,046,480	$233,581,703	$240,444,772	$247,956,219	$257,300,039	$264,970,422	$272,623,317	$281,305,832
Total CCE Generation Revenue Requirement	$3,158,815	$138,000,248	$253,791,173	$267,621,483	$274,306,556	$277,813,250	$268,204,588	$275,297,365	$284,488,802	$291,984,425	$299,397,972	$307,932,729
Bundled SCE Revenues	$14,645,671	$261,382,583	$496,123,003	$514,635,004	$530,143,564	$545,933,115	$562,626,036	$581,567,457	$598,848,517	$616,709,587	$635,822,737	$654,666,595
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$15,534,634	$277,247,985	$527,107,253	$549,510,013	$565,029,609	$580,825,616	$597,496,398	$616,292,391	$633,635,590	$651,544,644	$670,669,298	$689,598,429
Savings	**($888,963)**	**($15,865,402)**	**($30,984,250)**	**($34,875,009)**	**($34,886,045)**	**($34,892,501)**	**($34,870,362)**	**($34,724,934)**	**($34,787,073)**	**($34,835,057)**	**($34,846,561)**	**($34,931,835)**
Percent Savings	**-6.1%**	**-6.1%**	**-6.2%**	**-6.8%**	**-6.6%**	**-6.4%**	**-6.2%**	**-6.0%**	**-5.8%**	**-5.6%**	**-5.5%**	**-5.3%**

LA County Community Choice Aggregation
Financial Operating Model - RPS
Conservative Load Scenario
April 17, 2017

CCE Operating Costs	2018 Jan - June	2018 July - Dec	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Power Supply	$3,686,331	$59,211,244	$111,962,657	$117,976,475	$121,685,591	$125,380,007	$129,488,641	$134,945,200	$139,010,679	$143,244,209	$148,108,678	$152,533,166
Billing & Data Management	$12,960	$2,139,523	$4,770,904	$4,334,322	$4,393,056	$4,460,722	$4,552,050	$4,652,473	$4,756,607	$4,867,872	$4,973,415	$5,053,433
SCE Fees	$1,021,003	$1,793,163	$1,408,479	$1,421,766	$1,441,030	$1,463,225	$1,493,181	$1,526,119	$1,560,275	$1,596,770	$1,631,388	$1,657,634
Technical Services	$665,000	$665,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000
Staffing	$200,000	$935,000	$2,825,400	$2,881,908	$2,939,546	$2,998,337	$3,058,304	$3,119,470	$3,181,859	$3,245,496	$3,310,406	$3,376,615
General & Administrative expenses	$170,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698
Contribution to Annual Reserves	$0	$14,457,363	$9,409,247	$11,817,787	$14,521,143	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$14,521,143	$16,120,246	$16,765,621	$17,311,420	$17,908,931	$18,514,208	$19,132,746
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,091,983	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital	($9,295,079)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$34,678	$430,123	$832,763	$861,837	$880,978	$900,097	$847,456	$873,861	$894,539	$916,012	$940,318	$962,674
Total Operating Costs	-$3,505,107	$81,953,399	$137,149,416	$145,190,180	$151,763,673	$155,632,227	$161,475,068	$167,804,559	$172,643,952	$177,714,755	$183,420,907	$188,665,931
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	-$3,505,107	$81,953,399	$137,149,416	$145,190,180	$151,763,673	$155,632,227	$161,475,068	$167,804,559	$172,643,952	$177,714,755	$183,420,907	$188,665,931
Average CCE Rate ($/kWh)		$0.0304	$0.0526	$0.0551	$0.0570	$0.0579	$0.0595	$0.0612	$0.0623	$0.0635	$0.0649	#DIV/0!
Average SCE Generation Rate ($/kWh)		$0.0708	$0.0721	$0.0748	$0.0763	$0.0777	$0.0794	$0.0816	$0.0831	$0.0847	$0.0866	$0.0882
Total CCE Charges												
SCE Non-bypassable Charges	$1,180,317	$18,958,699	$39,645,264	$39,856,800	$39,834,068	$39,808,393	$24,983,834	$24,607,031	$24,469,887	$24,312,602	$24,097,190	$23,964,208
CCE Revenue Requirement	-$3,505,107	$81,953,399	$137,149,416	$145,190,180	$151,763,673	$155,632,227	$161,475,068	$167,804,559	$172,643,952	$177,714,755	$183,420,907	$188,665,931
Total CCE Generation Revenue Requirement	-$2,324,790	$100,912,098	$176,794,681	$185,046,980	$191,597,741	$195,440,619	$186,458,902	$192,411,591	$197,113,839	$202,027,357	$207,518,097	$212,630,139
Bundled SCE Revenues	$14,645,671	$235,244,325	$446,510,703	$463,171,504	$477,129,207	$491,339,804	$506,363,432	$523,410,711	$538,963,666	$555,038,628	$572,240,464	$589,199,935
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$13,850,089	$222,465,395	$422,779,153	$438,746,658	$453,248,489	$466,884,556	$480,151,337	$494,854,471	$508,725,722	$523,039,642	$538,219,934	$553,368,594
Savings	**$795,581**	**$12,778,929**	**$23,731,550**	**$24,424,846**	**$23,880,719**	**$24,455,248**	**$26,212,095**	**$28,556,240**	**$30,237,943**	**$31,998,987**	**$34,020,530**	**$35,831,341**
Percent Savings	**5.4%**	**5.4%**	**5.3%**	**5.3%**	**5.0%**	**5.0%**	**5.2%**	**5.5%**	**5.6%**	**5.8%**	**5.9%**	**6.1%**

LA County Community Choice Aggregation

Financial Operating Model - 50%

Conservative Load Scenario

April 17, 2017

CCE Operating Costs	2018 Jan - June	2018 July - Dec	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Power Supply	$4,015,169	$64,493,168	$121,665,422	$124,824,116	$128,149,222	$131,439,525	$135,126,586	$138,809,869	$142,556,052	$146,516,137	$150,547,210	$154,717,876
Billing & Data Management	$12,960	$2,139,523	$4,770,904	$4,334,322	$4,393,056	$4,460,722	$4,552,050	$4,652,473	$4,756,607	$4,867,872	$4,973,415	$5,053,433
SCE Fees	$1,021,003	$1,793,163	$1,408,479	$1,421,766	$1,441,030	$1,463,225	$1,493,181	$1,526,119	$1,560,275	$1,596,770	$1,631,388	$1,657,634
Technical Services	$665,000	$665,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000
Staffing	$200,000	$935,000	$2,825,400	$2,881,908	$2,939,546	$2,998,337	$3,058,304	$3,119,470	$3,181,859	$3,245,496	$3,310,406	$3,376,615
General & Administrative expenses	$170,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698
Contribution to Annual Reserves	$0	$12,455,222	$5,061,953	$10,009,758	$13,050,481	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$13,050,481	$14,168,097	$15,365,813	$17,857,700	$18,904,817	$19,918,553	$21,525,164
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,091,983	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital	($9,295,079)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$36,322	$456,533	$881,277	$896,075	$913,296	$930,394	$875,646	$893,184	$912,266	$932,372	$952,511	$973,597
Total Operating Costs	-$3,174,625	$85,259,592	$142,553,401	$150,264,030	$156,788,960	$160,251,380	$165,189,054	$170,288,744	$176,753,332	$181,998,928	$187,275,977	$193,253,983
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	-$3,174,625	$85,259,592	$142,553,401	$150,264,030	$156,788,960	$160,251,380	$165,189,054	$170,288,744	$176,753,332	$181,998,928	$187,275,977	$193,253,983
Average CCE Rate ($/kWh)		$0.0318	$0.0546	$0.0570	$0.0589	$0.0596	$0.0608	$0.0621	$0.0638	$0.0651	$0.0663	#DIV/0!
Average SCE Generation Rate ($/kWh)		$0.0708	$0.0721	$0.0748	$0.0763	$0.0777	$0.0794	$0.0816	$0.0831	$0.0847	$0.0866	$0.0882
Total CCE Charges												
SCE Non-bypassable Charges	$1,180,317	$18,958,699	$39,645,264	$39,856,800	$39,834,068	$39,808,393	$24,983,834	$24,607,031	$24,469,887	$24,312,602	$24,097,190	$23,964,208
CCE Revenue Requirement	-$3,174,625	$85,259,592	$142,553,401	$150,264,030	$156,788,960	$160,251,380	$165,189,054	$170,288,744	$176,753,332	$181,998,928	$187,275,977	$193,253,983
Total CCE Generation Revenue Requirement	-$1,994,308	$104,218,291	$182,198,666	$190,120,831	$196,623,028	$200,059,773	$190,172,888	$194,895,776	$201,223,219	$206,311,531	$211,373,167	$217,218,191
Bundled SCE Revenues	$14,645,671	$235,244,325	$446,510,703	$463,171,504	$477,129,207	$491,339,804	$506,363,432	$523,410,711	$538,963,666	$555,038,628	$572,240,464	$589,199,935
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$14,064,486	$225,909,114	$428,183,138	$443,820,508	$458,273,776	$471,022,222	$484,417,665	$499,284,744	$513,284,708	$527,732,274	$543,063,077	$558,351,556
Savings	**$581,185**	**$9,335,211**	**$18,327,565**	**$19,350,995**	**$18,855,432**	**$20,317,582**	**$21,945,768**	**$24,125,967**	**$25,678,957**	**$27,306,354**	**$29,177,386**	**$30,848,379**
Percent Savings	**4.0%**	**4.0%**	**4.1%**	**4.2%**	**4.0%**	**4.1%**	**4.3%**	**4.6%**	**4.8%**	**4.9%**	**5.1%**	**5.2%**

LA County Community Choice Aggregation
Financial Operating Model - 100%
Conservative Load Scenario
April 17, 2017

CCE Operating Costs	**2018 Jan - June**	**2018 July - Dec**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Power Supply	$5,548,178	$89,116,947	$167,471,888	$169,772,886	$173,411,076	$176,428,572	$179,615,223	$182,850,320	$186,044,507	$189,501,325	$192,969,546	$196,532,598
Billing & Data Management	$12,960	$2,139,523	$4,770,904	$4,334,322	$4,393,056	$4,460,722	$4,552,050	$4,652,473	$4,756,607	$4,867,872	$4,973,415	$5,053,433
SCE Fees	$1,021,003	$1,793,163	$1,408,479	$1,421,766	$1,441,030	$1,463,225	$1,493,181	$1,526,119	$1,560,275	$1,596,770	$1,631,388	$1,657,634
Technical Services	$665,000	$665,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000
Staffing	$200,000	$935,000	$2,825,400	$2,881,908	$2,939,546	$2,998,337	$3,058,304	$3,119,470	$3,181,859	$3,245,496	$3,310,406	$3,376,615
General & Administrative expenses	$170,000	$230,000	$356,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698
Contribution to Annual Reserves	$0	$11,104,855	$5,612,533	$15,574,747	$17,815,189	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$17,815,189	$20,674,937	$23,983,826	$28,975,455	$32,186,242	$35,376,344	$39,430,008
Debt Service (CCE Bonds & Start-up Costs)	$0	$2,091,983	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967	$4,183,967
Start-Up Capital	($9,295,079)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Uncollectibles	$43,987	$579,652	$1,110,310	$1,120,819	$1,139,606	$1,155,340	$1,098,089	$1,113,386	$1,129,709	$1,147,298	$1,164,622	$1,182,671
Total Operating Costs	-$1,633,950	$108,656,123	$189,139,480	$201,002,534	$207,041,832	$210,230,081	$216,406,974	$223,167,410	$231,576,984	$238,480,468	$245,368,215	$253,182,623
Other Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CCE Revenue Requirement	-$1,633,950	$108,656,123	$189,139,480	$201,002,534	$207,041,832	$210,230,081	$216,406,974	$223,167,410	$231,576,984	$238,480,468	$245,368,215	$253,182,623
Average CCE Rate ($/kWh)		$0.0414	$0.0725	$0.0763	$0.0778	$0.0782	$0.0797	$0.0814	$0.0836	$0.0853	$0.0868	#DIV/0!
Average SCE Generation Rate ($/kWh)		$0.0708	$0.0721	$0.0748	$0.0763	$0.0777	$0.0794	$0.0816	$0.0831	$0.0847	$0.0866	$0.0882
Total CCE Charges												
SCE Non-bypassable Charges	$1,180,317	$18,958,699	$39,645,264	$39,856,800	$39,834,068	$39,808,393	$24,983,834	$24,607,031	$24,469,887	$24,312,602	$24,097,190	$23,964,208
CCE Revenue Requirement	-$1,633,950	$108,656,123	$189,139,480	$201,002,534	$207,041,832	$210,230,081	$216,406,974	$223,167,410	$231,576,984	$238,480,468	$245,368,215	$253,182,623
Total CCE Generation Revenue Requirement	-$453,633	$127,614,822	$228,784,745	$240,859,334	$246,875,900	$250,038,474	$241,390,809	$247,774,441	$256,046,871	$262,793,070	$269,465,405	$277,146,831
Bundled SCE Revenues	$14,645,671	$235,244,325	$446,510,703	$463,171,504	$477,129,207	$491,339,804	$506,363,432	$523,410,711	$538,963,666	$555,038,628	$572,240,464	$589,199,935
Total CCE Customer Bill Revenues (Power Supply and Delivery)	$15,534,634	$249,523,186	$474,769,217	$494,559,012	$508,526,648	$522,743,054	$537,746,758	$554,663,152	$570,272,031	$586,390,179	$603,602,368	$620,638,586
Savings	**($888,963)**	**($14,278,862)**	**($28,258,514)**	**($31,387,508)**	**($31,397,440)**	**($31,403,251)**	**($31,383,325)**	**($31,252,440)**	**($31,308,366)**	**($31,351,551)**	**($31,361,905)**	**($31,438,651)**
Percent Savings	**-6.1%**	**-6.1%**	**-6.3%**	**-6.8%**	**-6.6%**	**-6.4%**	**-6.2%**	**-6.0%**	**-5.8%**	**-5.6%**	**-5.5%**	**-5.3%**