County of Los Angeles

Los Angeles Community Choice Energy

Business Plan Update

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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)

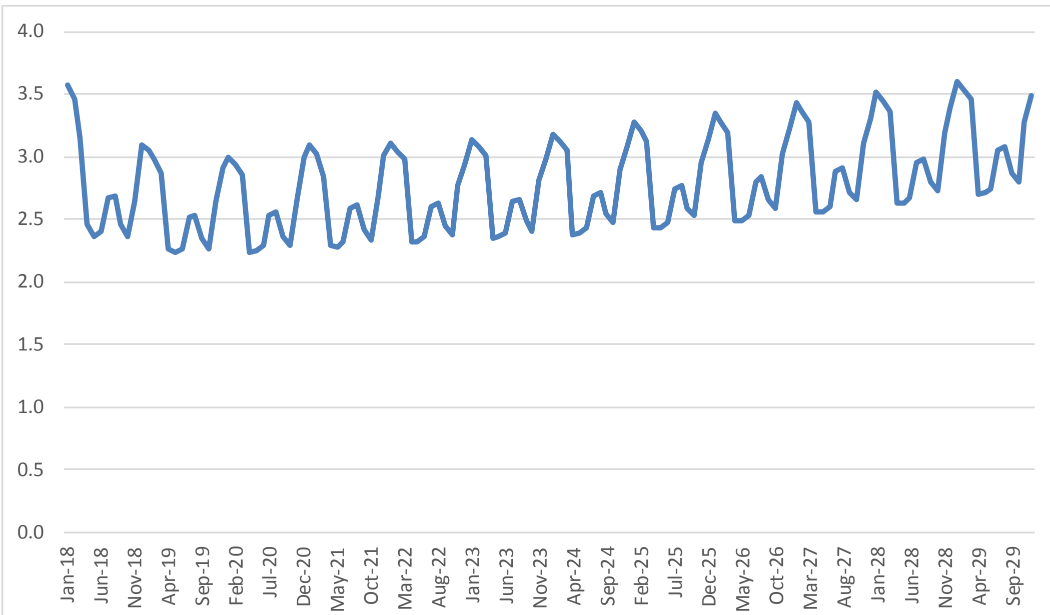
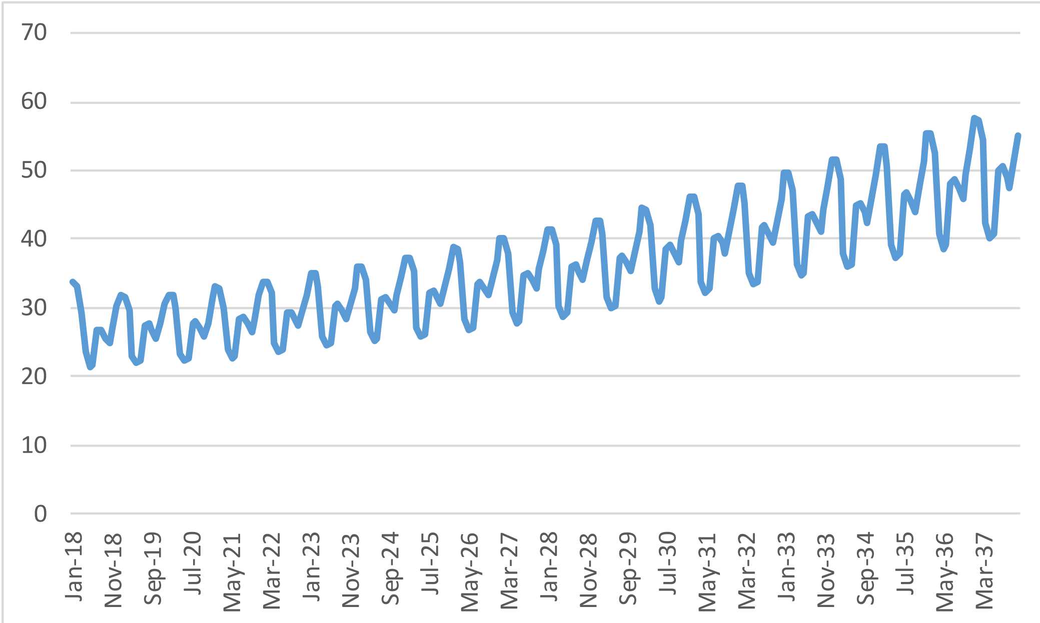


Exhibit 4 shows the resulting monthly southern California wholesale market price forecast. The levelized value of market prices over the study period is $34.6/MWh assuming a 4 percent discount rate. This is **a decrease of nearly $5/MWh and 12 percent from the levelized value of $39.5/MWh included in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

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



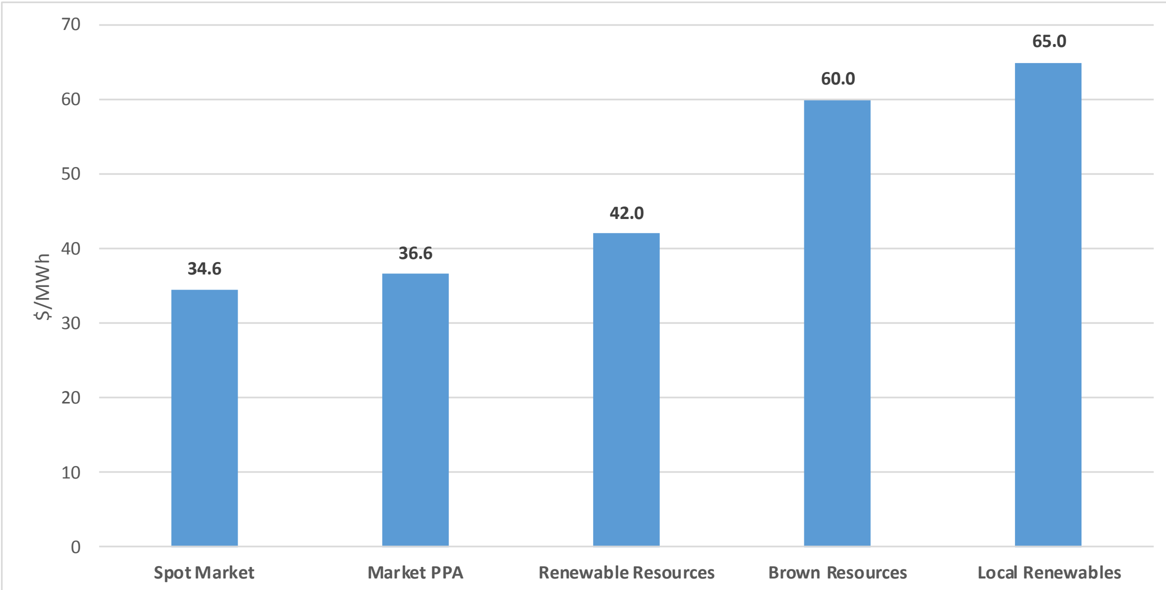
Wholesale power prices were used to calculate balancing market purchases and sales. When the LACCA's loads are greater than its resource capabilities, the LACCA's scheduling agent will schedule balancing purchases and the LACCA will incur balancing market purchase costs. When the LACCA's loads are less 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.

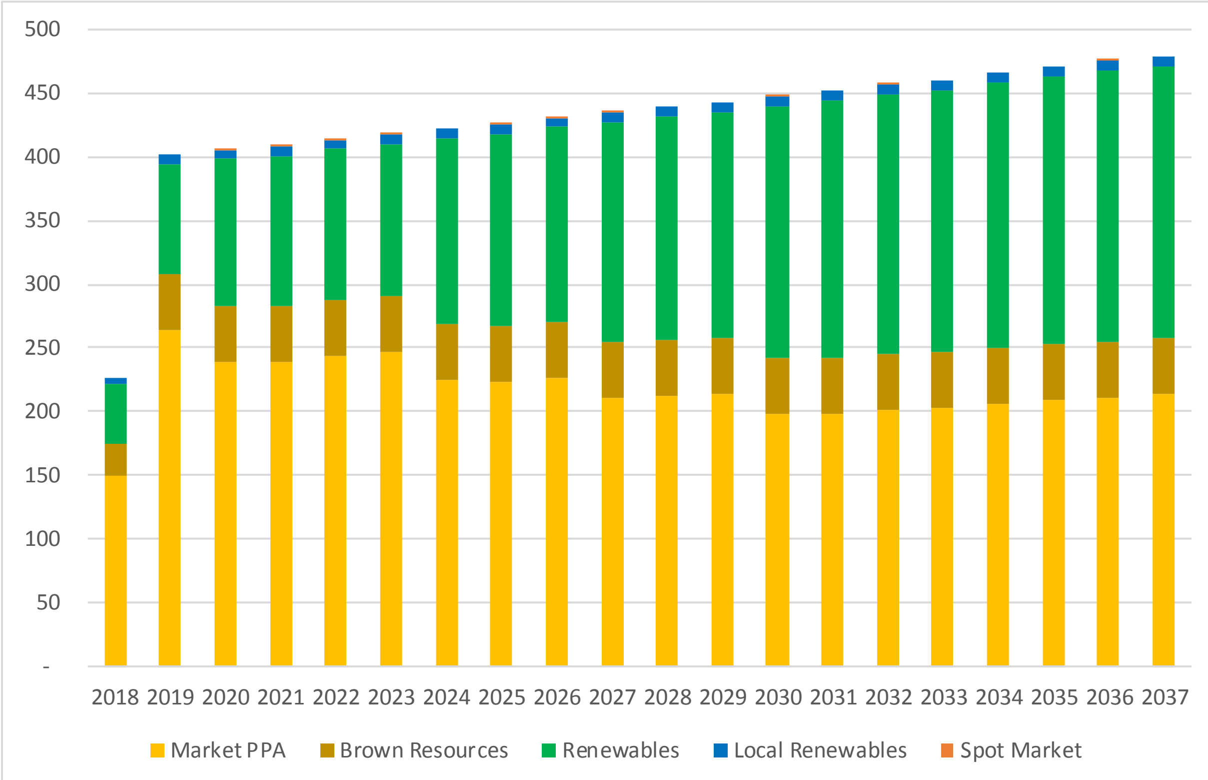
Portfolio 1: Meet Current RPS Requirements

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)

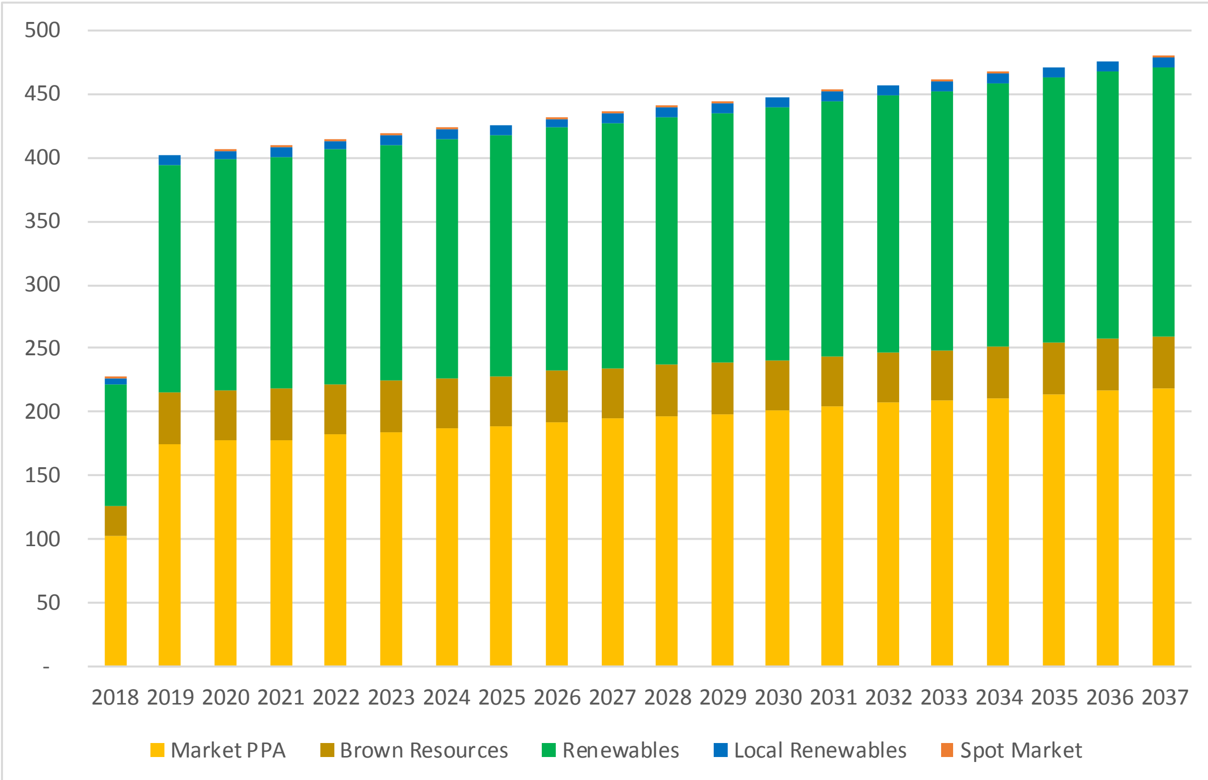


The green bars shown in Exhibit 6 above increase each year along with California's RPS requirements.

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.

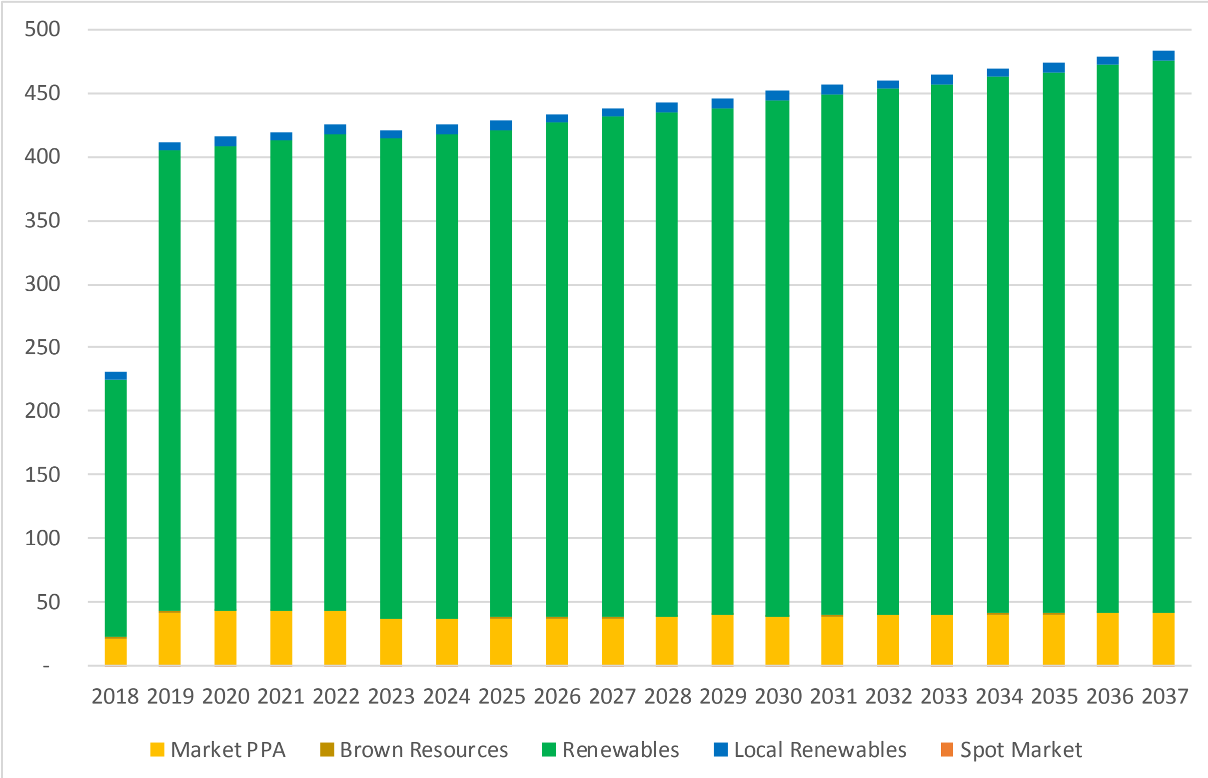
Exhibit 7
Portfolio 2: Serve 50% of Retail Load with Renewables (aMW)



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)

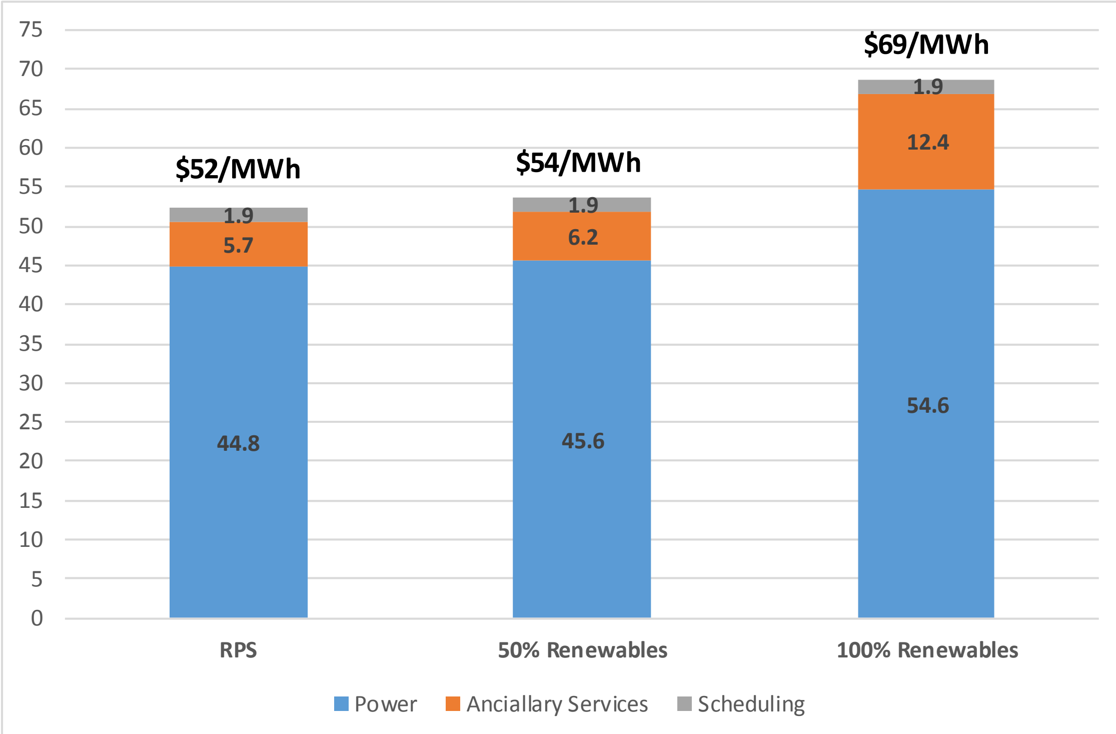


As shown above, there is a small amount of market PPA and brown resource power included in Portfolio 3 due to distribution and transmission system losses. The renewable energy requirements in the state's RPS are based on retail energy sales. To be consistent it was assumed that the 100% renewable energy 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.

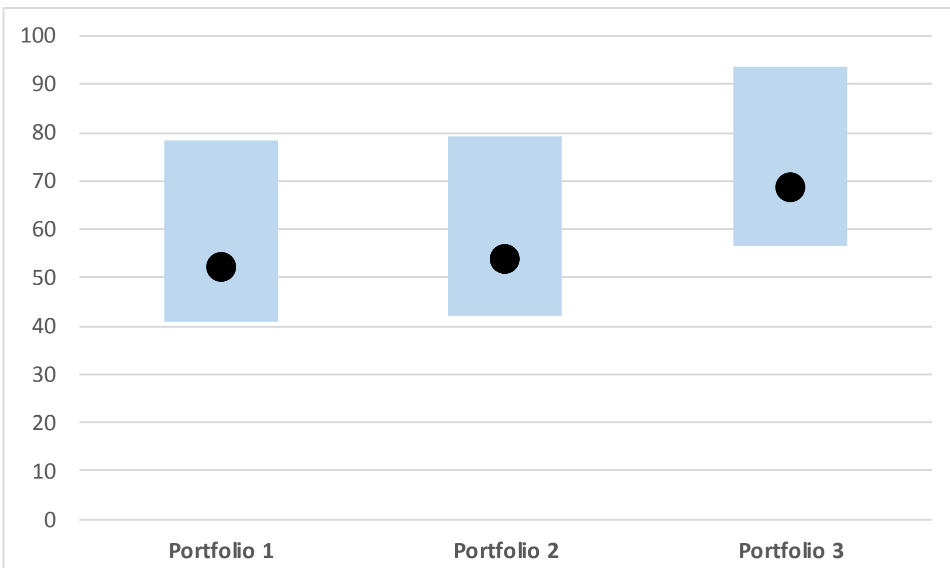
Exhibit 9 above shows the base case 20-year levelized cost of each portfolio. Since resource costs are based on forecast renewable and brown resource market prices and updated forecast natural gas and wholesale market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculation 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

	2018	2018										
CCE Operating Costs	**Jan - June**	**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%**