FOR THE CENTRAL COAST REGION

TECHNICAL FEASIBILITY STUDY ON COMMUNITY CHOICE AGGREGATION

FINAL REPORT
AUGUST 2017

WILLDAN
FINANCIAL SERVICES

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Central Coast Power

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Executive Summary

A. Community Choice Aggregation Overview

Community Choice Aggregation (CCA) is a program for local jurisdictions in California to procure electricity supply for, and develop energy resources to serve, jurisdictional customers. According to the Local Government Commission,[1] the most common reasons for forming a CCA program are to:

- Increase use of renewable generation,
- Exert control over rate setting,
- Stimulate economic growth, and
- Lower rates.

When a CCA is formed, the local incumbent electric investor-owned utility (IOU) continues to deliver power through its transmission and distribution facilities to customers within its service territory. The IOU also provides monthly customer metering and billing services. The local CCA program procures the electric commodity and sells it to its customers, with the intent that the electricity is less expensive, more local, and/or uses more renewable generation than the current utility alternative. The two components, delivery and generation, already appear separately on customer bills. The incumbent utility continues to provide billing services, but the CCA's generation rate replaces the IOU's generation rate on customer bills.

Jurisdictions in California have formed CCA programs in efforts to provide constituents the option to be served with a greater mix of renewable and carbon-free energy generation than is provided by the incumbent utility. Eight CCA programs are currently operational in California, with ten more launching in 2018. At least 17 additional jurisdictions are exploring and/or are in the planning stages for CCA.

Ten local governments joined with the County of Santa Barbara to fund this Study, and the following jurisdictions formed an Advisory Working Group in December 2015:

- *Unincorporated San Luis Obispo County*
- *Unincorporated Santa Barbara County, plus:*
  - *City of Carpinteria*
  - *City of Santa Barbara*
- *Unincorporated Ventura County, plus:*
  - *City of Camarillo*
  - *City of Moorpark*
  - *City of Ojai*
  - *City of Simi Valley*
  - *City of Thousand Oaks*
  - *City of Ventura*

B. Study Scope and Purpose

This technical feasibility Study for CCA for the Central Coast Region (Study) was directed by the Advisory Working Group (AWG), which was formed by eleven governments in the Santa Barbara, San Luis Obispo, and Ventura County (Tri-County) Region. The Advisory Working Group collectively has named the potential CCA "Central Coast Power." The Study's purpose is to advise and guide the Tri-County Region in understanding the feasibility of forming a new CCA program. This Study considers required startup and operational processes and evaluates multiple procurement scenarios to determine whether a CCA program in the Tri-County Region is: a) financially feasible; and b) will meet its stated policy objectives. The Study results do not necessarily apply to one or more of the Tri-County local governments joining an existing CCA program.

This Study evaluates the financial and economic viability of a CCA by:

- Forecasting the CCA electricity demand requirements (load) and potential customers by class;
- Estimating the costs of procuring the necessary electricity supply; and
- Projecting the costs of starting up and administering a CCA program.

The Study also enumerates the potential benefits and associated risks of a CCA program and discusses implementation requirements.

C. Energy Procurement and Study Scenarios

Energy procurement is complex and the total cost of procurement is subject to changes in both market conditions (price) and consumption (volume). Load Serving Entities (LSEs)—IOUs, CCAs, and Electricity Service Providers (ESPs)—must manage both load forecasting and energy procurement with a robust risk management approach to account for the dynamic and volatile nature of power markets and load.

Throughout the report, the term LSE is used to provide illustrative trends that are affecting the Tri-County Region as a whole, regardless of whether the electricity is provided by an IOU, ESP or CCA program. For our purposes, a CCA program is a subset of the more broad LSE term.

Given the uniqueness of multiple municipalities partnering to commission this feasibility Study, the Advisory Working Group established eight geographic participation scenarios. These eight scenarios were selected to explore the feasibility of different sizes and configurations for the CCA program and the potential effect of customer demographics. Although the entire Tri-County Region may not ultimately pursue CCA, certain jurisdictions may decide to move forward with CCA. The eight participation scenarios defined for this Study are:

1. All Tri-County Region
2. AWG Jurisdictions
3. All San Luis Obispo County
4. Unincorporated San Luis Obispo County
5. All Santa Barbara County
6. Unincorporated Santa Barbara County
7. All Ventura County
8. City of Santa Barbara

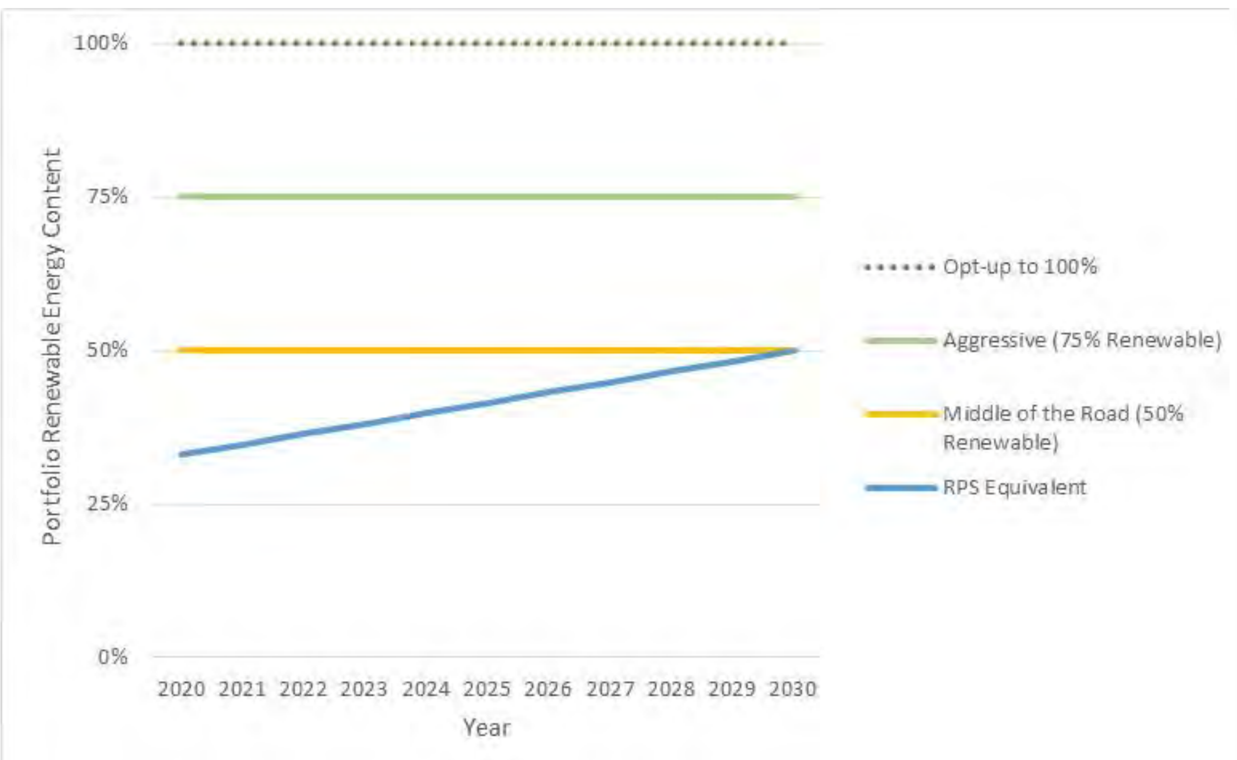
In addition to the eight participation scenarios, three renewable energy content scenarios were considered. All scenarios include a customer option to opt-up to a 100% renewable energy product. For the purposes of this Study, 2% of customers were assumed to opt-up to the 100% renewable option. The three renewable energy content scenarios are as follows:

- **RPS Equivalent**: This scenario assumes that Central Coast Power would offer its base electricity product to all customers starting at 33% renewable content in 2020 and ramping up to 50% renewable content by 2030 in alignment with the California minimum Renewable Portfolio Standard (RPS).[2]
- **Middle of the Road**: This scenario assumes that Central Coast Power would offer its base electricity product to all customers using 50% renewable content for the entire Study period.
- **Aggressive**: This scenario assumes that Central Coast Power would offer its base electricity product to all customers using 75% renewable content for the entire Study period.

This Study evaluates an eleven-year period from 2020 to 2030, although a potential CCA program could begin earlier than 2020. Figure ES-1 illustrates how the renewable energy content in the RPS Equivalent scenario grows over time, and in the other two scenarios remains constant across the Study period. These three scenarios were chosen to illustrate the relative differences in cost given different levels of renewable supply content. Actual CCA implementation may choose to follow a progression of increasing renewable generation over that period based on cost competitiveness. For example, Central Coast Power CCA may launch in 2020 with 50% renewable content and progress to 75% renewable content by 2030, assuming it can do so at a cost advantage to the IOUs.

To enhance report readability, the main body of this report presents results for the AWG Jurisdictions participation scenario, for the RPS Equivalent, Middle of the Road, and Aggressive renewable energy content scenarios. Detailed results for the other seven participation scenarios are provided in Appendices C, and E through J.

Figure ES-1 Renewable Energy Content Modeled in this Study



The fundamental operational role of a CCA is to forecast customer electricity needs and procure energy and associated energy related services. Power procurement consists of forecasting and risk management tasks. Power procurement planning and day-to-day decision making rely heavily on short-term and long-term forecasts of consumer demand for power. The procurement function must also evaluate and assess the inherent risks associated with demand forecasting and develop appropriate risk mitigation strategies. Though no one can predict future energy demand with 100% certainty, logical, data-driven, industry-standard methodologies to forecasting are available to provide a realistic outlook of energy demand under a variety of future scenarios. Brief discussions covering the forecasts for customer power demand and power procurement costs are provided in the following segments.

The fundamental operational role of a CCA is to forecast customer electricity needs and procure energy and associated energy related services.

D. Customer Demand

Energy is measured in several units throughout this study: kilowatt-hours (kWh), which is the unit used on customer bills; megawatt-hours (MWh), where 1 MWh equals 1,000 kWh; and gigawatt-hours (GWh), where 1 GWh equals 1,000 MWh or 1,000,000 kWh.

As shown in Figure ES-2, Ventura County is the largest electricity consumer of the three counties considered in this Study, followed by Santa Barbara and San Luis Obispo Counties. Collectively, customers in the incorporated cities in San Luis Obispo and Ventura Counties consume more electricity than customers in the unincorporated county. The reverse is true in Santa Barbara County.

Figure ES-2 Annual Demand in Gigawatt-hours (GWh) by County

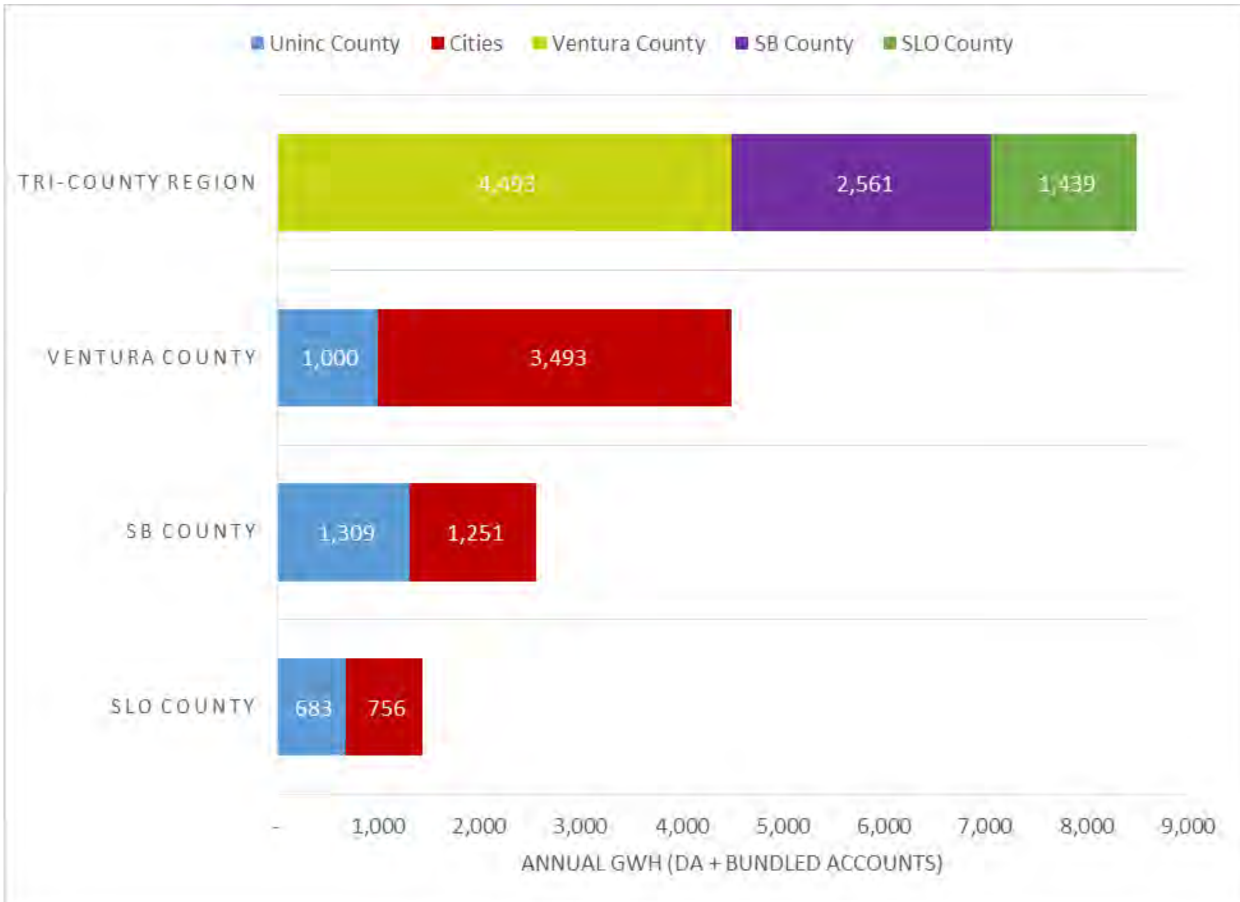
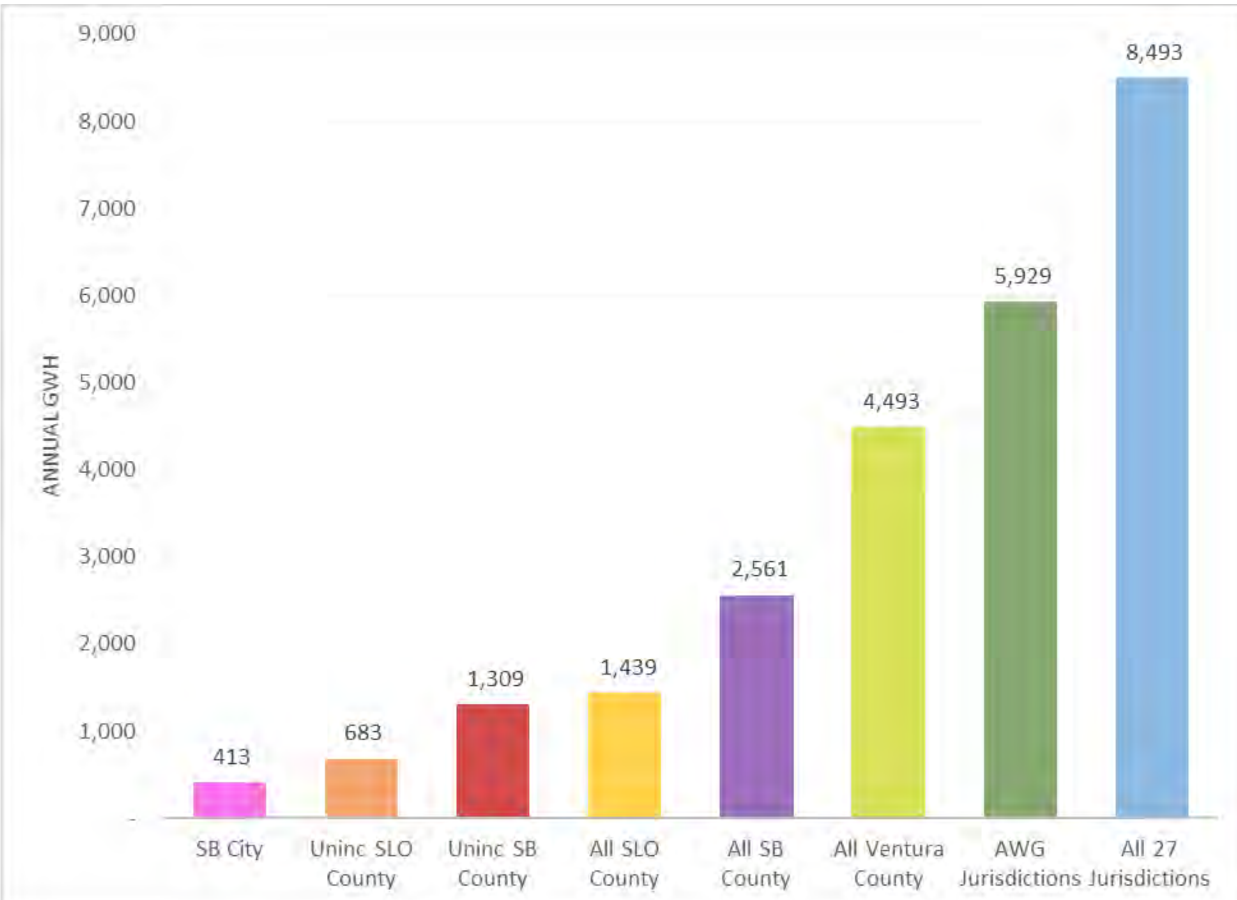


Figure ES-3 shows the annual electricity consumption for each of the Study's eight geographic participation scenarios. The consumption and number of accounts generally mirror each other, with the exception of unincorporated San Luis Obispo and Santa Barbara Counties.

Figure ES-3 Annual Demand in GWh for Each Geographic Participation Scenario



Electricity consumption is forecasted to grow moderately over the Study period, however continued customer adoption of distributed generation (DG) solar photovoltaic (PV) is expected to offset this growth. DG PV reduces the amount of energy that needs to be provided by the potential CCA. Figure ES 4 illustrates the growth of customer-owned DG PV since the year 2000 and illustrates a forecast for additional DG PV capacity if this trend continues. Table ES 1 lists the forecasted annual energy consumption, annual DG PV generation, and the annual net load (consumption-generation) served by the potential CCA for the AWG Jurisdictions participation scenario. In summary, a Central Coast Power CCA would likely sell less electricity each year given customer DG PV adoption.

Figure ES-4 California Solar Initiative Incentivized Customer-Owned Solar Photovoltaic in the Region with 2030 Forecast

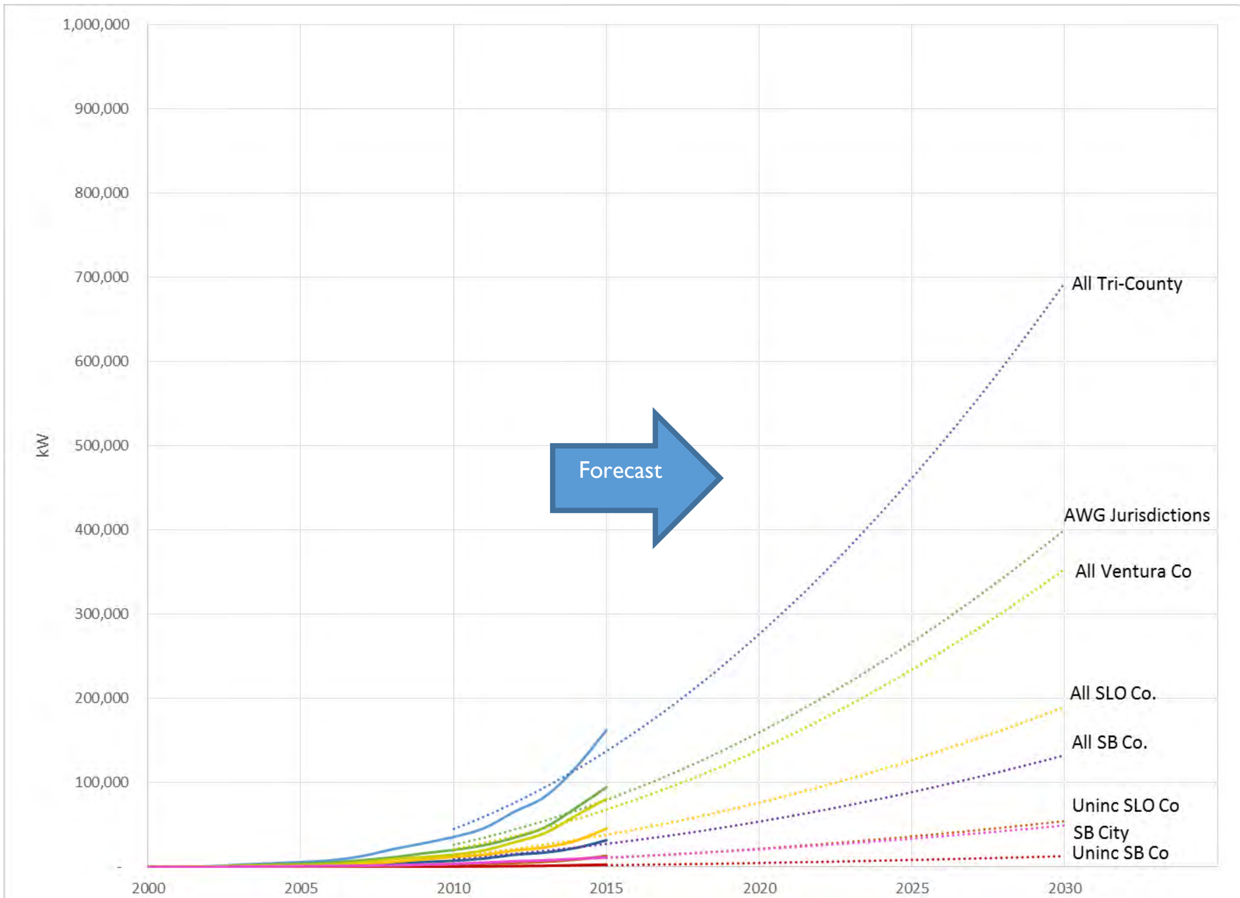


Table ES-1 Load, Distributed Generation, and Net Load Forecast, AWG Jurisdictions Participation Scenarios

Year	Annual Energy Consumption (MWh)	Annual DG Generation (MWh)	Annual Net Load Served by LSE (MWh)
2020	6,698,164	164,987	6,533,177
2021	6,735,965	202,979	6,532,985
2022	6,777,276	244,414	6,532,862
2023	6,811,982	287,988	6,523,995
2024	6,868,761	335,074	6,533,686
2025	6,888,329	381,954	6,506,375
2026	6,930,669	431,948	6,498,721
2027	6,971,608	483,660	6,487,948
2028	7,026,296	538,288	6,488,008
2029	7,047,280	592,489	6,454,791
2030	7,085,173	650,280	6,434,893

As explained in Section II Technical and Financial Analysis, the increasing amount of DG PV also creates more volatile customer load due to the variable nature of its energy output. Solar generation depends on solar irradiance, which can fluctuate significantly over very short periods of time (within seconds) due to weather patterns and resulting cloud cover.

E. Power Procurement Cost Forecasts

CCAs, like all LSEs, satisfy customer demand for electricity by managing a power supply portfolio, a collection of supply-side resources. For the purposes of this Study, a power supply portfolio is designed to acquire two distinct commodities: energy, typically measured in MWh, and resource adequacy capacity, typically measured in megawatts (MW). Energy resources include natural gas generation, RPS compliant renewable energy generation, energy storage, and California Independent System Operator (CAISO) day-ahead and real-time market purchases. Resource adequacy is used to make sure there is sufficient capacity to produce electricity during peak demand periods.

This Study projects decreasing costs for all energy resources considered, except for energy procured in the CAISO markets, where average pricing remains constant and large fluctuations are due to variability in renewable generation for both utility scale resources and customer-owned DG PV. Actual CAISO real-time market prices from January 2014 through October 2016 for the Tri-County Region average around $36 per megawatt-hour (MWh). However, the range of prices around that mean varied greatly, reaching a high of $4,377 per MWh during shortages of supply relative to demand, and a low of -$1,277 per MWh—meaning that CAISO will pay participants to take power—when supply exceeds demand. The high level of DG PV penetration in California, combined with solar and wind energy's variable nature, accounts for much of this market volatility. This Study has modeled renewable resource variability and the CCA's associated exposure to CAISO market prices.

Table ES-2 presents the Study forecast for the average annual power procurement cost for the AWG Jurisdictions participation scenario for the three renewable supply scenarios. As can be seen in these data, the average cost of power procurement for the CCA rises as more renewable energy content is added because renewable generation is forecast to be more expensive than alternative non-renewable resources, despite a slight downward trend in renewable energy prices.

Table ES-2 Average Annual Power Procurement Costs ($ per MWh), AWG Jurisdictions Scenarios

Year	RPS Equivalent	Middle of the Road (50% Renewable)	Aggressive (75% Renewable)
2020	$67	$74	$87
2021	$66	$74	$85
2022	$66	$74	$85
2023	$66	$72	$85
2024	$66	$72	$84
2025	$66	$71	$84
2026	$67	$70	$84
2027	$68	$70	$84
2028	$68	$69	$83
2029	$68	$69	$82
2030	$68	$69	$81

The total energy requirements served by various power supply options, including PPAs, the CAISO day-ahead and real-time markets, among others, change depending on scenario, however, the price of each option does not. This is what would be expected in actuality, as the amount of energy procured by the CCA would have little to no bearing on the prevailing PPA and market prices on a long-term basis.

In support of the power procurement cost forecast, data from the U.S. Department of Energy's Energy Information Administration's Annual Energy Outlook 2017,[3] which provides estimates of renewable generation costs on a regional basis, were examined. This data is used by utilities, energy consultancies, and others to help understand current and future energy-related pricing trends and is based on real-world project construction, financing, ownership, and ongoing operations and maintenance costs. Table ES-3 shows the various costing components for a new solar photovoltaic project and a new wind project, assuming they are installed on sites where there is no need to work within the constraints imposed by existing buildings or infrastructure (greenfield projects). This cost data supports all-in pricing at around $67 per MWh for wind resources and $101 per MWh for solar PV resources.

Table ES-3 Energy Information Administration Cost Estimates for New Wind and Solar Energy Resources in California

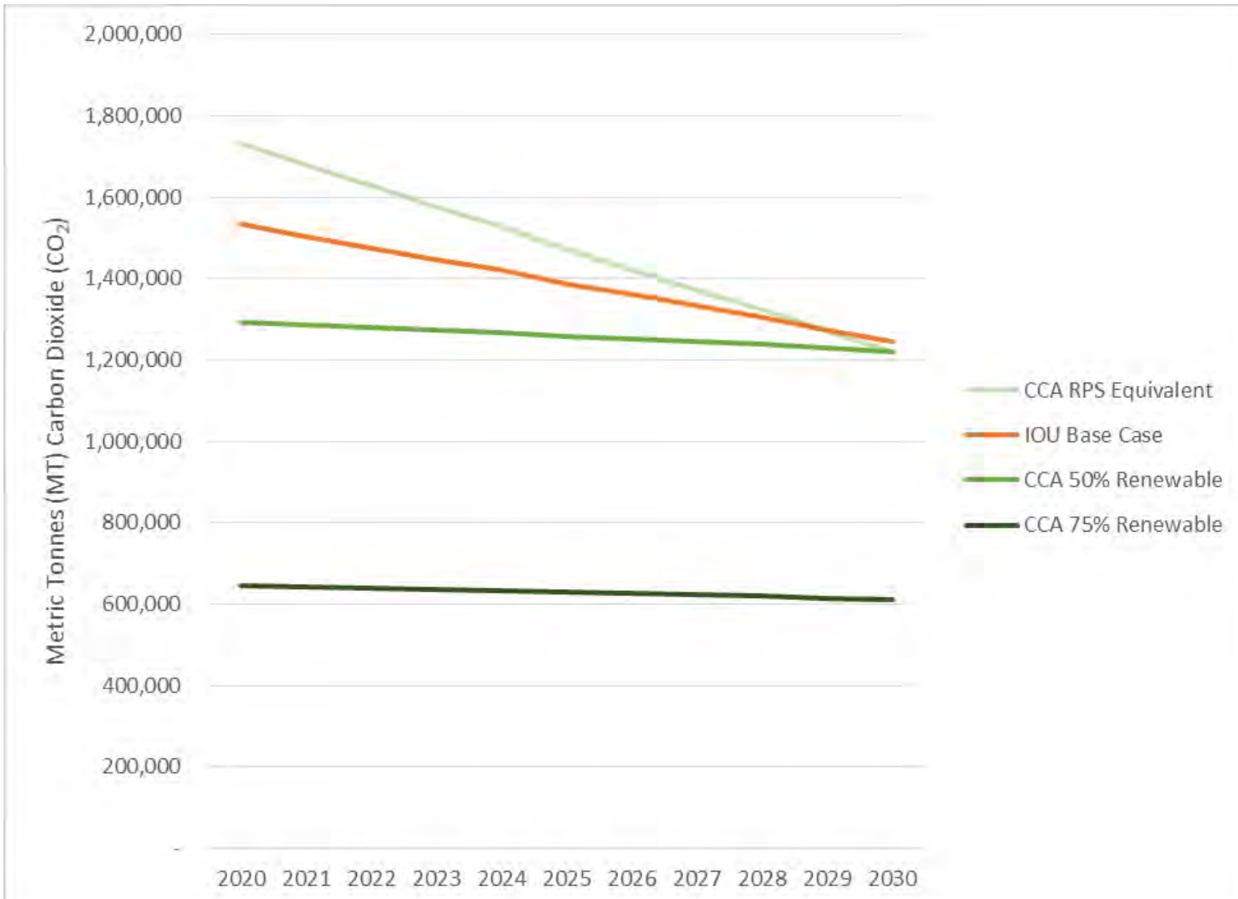
Description	Wind Farm – Onshore	Utility-Scale Photovoltaic
Configuration	100 MW; 56 turbines at 1.79 MW each	20 MW, Alternating Current, Fixed Tilt
Installation Type	Greenfield Installation	Greenfield Installation
Total Capacity (MW)	100	20
Capacity Factor (National Average, Jan. 2016-Apr. 2017)	36.59%	26.76%
Total Project Cost, California-Mexico Region ($ per kW-installed)	$2,010	$2,578
Total Project Cost, California-Mexico Region ($)	$201,000,000	$51,560,000
Variable O&M ($ per MWh)	$ -	$ -
Fixed O&M ($ per kW-year)	$46.71	$21.66
Weighted Average Cost of Capital (%)	5.50%	5.50%
Debt Finance Term (years)	20	20
Financing Costs per Year ($)	$16,819,545	$4,314,506
Fixed O&M Costs per Year ($)	$4,671,000	$433,200
Total Project Costs per Year ($)	$21,490,545	$4,747,706
Energy Production per Year (MWh)	320,528	46,884
Per Unit Cost ($ per MWh)	**$67.05**	**$101.27**

Like all energy price forecasts, the one used within the Study—just as those used within other CCA feasibility studies—may or may not accurately reflect actual future conditions, which are unknown and not predictable. Various market drivers may change resulting in different outcomes from those assumed here. The forecast used herein is a reasonable estimate for the purposes of analyzing the feasibility of CCA within the Tri-County Region, but no warranties as to the accuracy of forecast prices for power purchase agreements or CAISO market commodities are implied or should be inferred. For example, large hydroelectric generation resources owned and managed by the IOUs were not significantly utilized during the recent drought years through 2016. Rainfall in the winter of 2016-2017 filled the hydroelectric reservoirs, enabling a low cost, carbon-neutral generation resource for the IOUs. Generally speaking, all other things being equal, increased hydro production will lower IOU generation revenue requirements and could have a dampening effect on IOU rates, potentially lowering the rates required for the CCA to be competitive.

F. Greenhouse Gas Emissions Impact

This Study also evaluated the greenhouse gas (GHG) emissions impact of the renewable energy content of the CCA's portfolio—including the 100% renewable energy product assumed to be chosen by 2% of customers—relative to that of the incumbent IOUs, Southern California Edison (SCE) and Pacific Gas and Electric (PG&E). For the purposes of this comparison, the IOU Base Case assumes the IOUs will progress from currently published 2020 RPS levels of renewable generation linearly to the 50% RPS goal in 2030. Although each IOU may elect to exceed RPS requirements as they have in recent history and relative to 2020 requirements, for example PG&E submitted a joint proposal to decommission the El Diablo nuclear power station and voluntarily reach 55% RPS by 2031,[4] neither IOU has publicly stated firm plans to exceed RPS targets. California is currently considering Senate Bill 100, which would increase the renewable energy mandate to: 50% by December 31, 2026 and 60% by December 31, 2030.[5] Figure ES-5 summarizes the GHG impact analysis results for the IOU renewable scenario and three CCA renewable scenarios.

Figure ES-5 GHG Emissions Impact Analysis, AWG Jurisdictions Participation Scenarios



Large hydroelectric generation resources owned and managed by the IOUs do not count towards RPS goals and were also not significantly utilized during the recent drought years through 2016. Rainfall in the winter of 2016-2017 filled the hydroelectric reservoirs enabling a low cost, carbon-neutral generation component for the IOUs. In addition, the pumped hydro energy storage that can balance the variability of other sources of renewable generation also relies on rain to fill reservoirs. Future rainfall and drought conditions are unknown, and therefore the future utilization of large hydroelectric generation by the IOUs cannot be predicted. Additional use of hydro resources or increases to the IOU RPS content would result in lower GHG emissions for the IOUs, potentially decreasing the additional GHG reduction benefit of the CCA program.

G. Cost of Service and Financial Pro Forma Analysis

The cost of service analysis relied on traditional utility ratemaking principles and followed an industry standard methodology for creation of a financial pro forma to forecast the future economic and financial performance of the CCA program. The Study assessed financial feasibility in terms of the ability of the CCA program to realistically deliver competitive costs for customers while paying its substantial start-up and agency formation costs and ongoing operating expenses.

The Test Year is the future annualized period for which operating costs are analyzed and rate proxies established. The Study Test Year is based on forecasts of CCA operating conditions for years 2022, 2023, and 2024 and represents a twelve-month period of normalized operations selected to evaluate the cost of service for each customer class and the adequacy of rate proxies to provide sufficient revenue.

The first step in the cost of service analysis was developing the projected CCA program revenue requirement: the amount of revenue required to cover the costs of the CCA program, including all operating and non-operating expenses, debt-service payments, a contingency allotment, a working capital reserve, and a rate stabilization fund. The revenue requirement was based on a comprehensive accounting of all pertinent costs and projections of customer participation; assumptions and input development are described later in this report. Cost assumptions relied on historical publicly-available information, power cost forecasts conducted for this Study, data provided by PG&E and SCE, and subject matter expertise gained working with a host of public utilities and similar organizations. Table ES-4 summarizes the CCA program Test Year revenue requirements for the AWG Jurisdictions participation scenarios

Table ES-4 Test Year CCA Revenue Requirements, AWG Jurisdictions Participation Scenarios

Description	AWG Jurisdictions Participation Scenarios		
	RPS Equivalent	Middle of the Road	Aggressive
REVENUE REQUIREMENT			
Baseload			
Total Operating Expenses Excluding Power Costs	$ 10,146,683	$ 10,256,373	$ 10,482,215
Total Non-Operating Expenses	16,959,517	18,158,147	20,239,969
Power Costs	461,419,035	489,933,855	549,930,521
Contingency/Rate Stabilization Fund	$ 54,171,111	$ 57,535,423	$ 64,613,615
BASELOAD REVENUE REQUIREMENT	**$ 542,696,345**	**$ 575,883,798**	**$ 645,266,320**
Opt-up to 100% RPS			
Total Operating Expenses Excluding Power Costs	$ 207,075	$ 209,314	$ 213,923
Total Non-Operating Expenses	346,113	370,574	413,061
Power Costs	12,617,576	12,617,576	12,617,576
Contingency/Rate Stabilization Fund	$ 1,105,533	$ 1,174,192	$ 1,318,645
OPT-UP TO 100% RPS REVENUE REQUIREMENT	**$ 14,276,297**	**$ 14,371,657**	**$ 14,563,205**
TOTAL REVENUE REQUIREMENT	**$ 556,972,642**	**$ 590,255,454**	**$ 659,829,525**

CCA program customer participation was assumed to be constant for each participation scenario across the three renewable energy content scenarios examined. For all scenarios, an opt-out rate of 15% was used for all rate classes for all years, meaning that 15% of bundled customers by load in each rate class were assumed to opt out of the CCA program.[6] This 15% opt-out rate is in addition to an estimated 23.5% of AWG Jurisdictions scenario load that represents typically large commercial customers who are likely to remain with their existing Direct Access (DA) ESP. Other CCA feasibility studies have supported the assertion that opt-out rates, within a reasonable range, have little bearing on CCA feasibility. Figure ES-6 and Figure ES-7 summarize Test Year customer accounts by rate class and Test Year customer usage by rate class for the AWG Jurisdictions participation scenarios, respectively. Average CCA Test Year customer profiles for the three AWG Jurisdictions participation scenarios are provided in Table ES-5.

Figure ES-6 Test Year CCA Customer Accounts, AWG Jurisdictions Participation Scenarios

Figure ES-7 Test Year CCA Customer Usage, AWG Jurisdictions Participation Scenarios

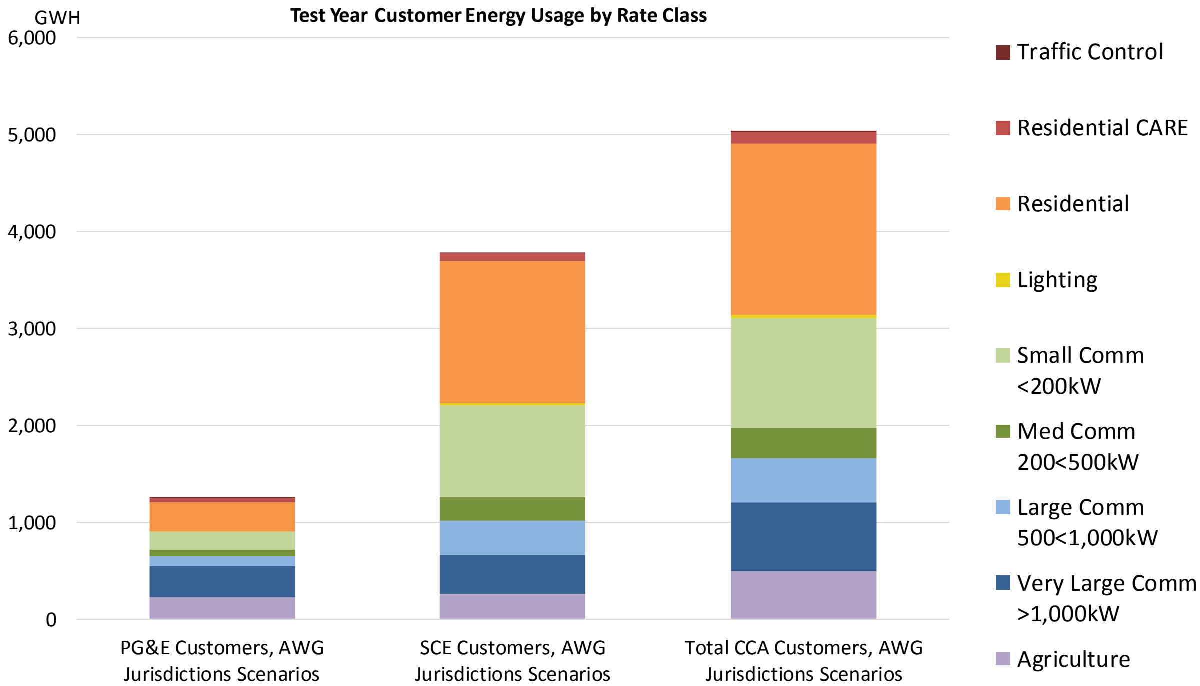


Table ES-5 Test Year CCA Customer Accounts and Usage, AWG Jurisdictions Participation Scenarios

Line	Description	Test Year Accounts	Test Year Annual Load (MWh)	Test Year Average Monthly Load (kWh/Account)
1	BASELOAD			
2	Agriculture	6,454	490,772	6,337
3	Very Large Comm >1,000kW	13	718,495	4,673,350
4	Large Comm 500<1,000kW	405	441,022	90,742
5	Med Comm 200<500kW	576	297,829	43,094
6	Small Comm <200kW	40,034	1,124,051	2,340
7	Lighting	1,757	26,357	1,250
8	Residential	256,812	1,709,325	555
9	Residential CARE	22,929	124,036	451
10	Traffic Control	841	2,811	278
11	**TOTAL BASELOAD**	**329,821**	**4,934,699**	**1,247**
12	OPT-UP TO 100% RPS (MWH)			
13	Agriculture	-	-	-
14	Very Large Comm >1,000kW	-	-	-
15	Large Comm 500<1,000kW	9	10,071	90,742
16	Med Comm 200<500kW	29	15,106	43,094
17	Small Comm <200kW	538	15,106	2,340
18	Lighting	-	-	-
19	Residential	9,078	60,425	555
20	Residential CARE	-	-	-
21	Traffic Control	-	-	-
22	**TOTAL OPT-UP TO 100% RPS**	**9,655**	**100,708**	**869**
23	**TOTAL CCA**	**339,476**	**5,035,407**	**1,236**
	CUSTOMERS OPTING UP TO 100% RENEWABLES		Portion of Opt Up	Portion of Total CCA
24	Agriculture		0%	0.00%
25	Very Large Comm >1,000kW		0%	0.00%
26	Large Comm 500<1,000kW		10%	0.20%
27	Med Comm 200<500kW		15%	0.30%
28	Small Comm <200kW		15%	0.30%
29	Lighting		0%	0.00%
30	Residential		60%	1.20%
31	Residential CARE		0%	0.00%
32	Traffic Control		0%	0.00%
33	**TOTAL**		**100%**	**2.00%**

While rate design was not part of the Study scope, based on the detailed pro forma analysis, CCA rate proxies by customer class by IOU jurisdiction were developed. Rate proxies represent the amount of revenue by customer class required to make the CCA financially solvent, based on the Test Year. Based on this analysis, CCA baseline customers would have all-in rate proxies that are higher than both PG&E and SCE for most rate classes for all participation and renewable energy content scenarios examined. Table ES-6 through Table ES-8 present the generation rate differences between the CCA and PG&E and SCE for the AWG Jurisdictions participation scenarios for the RPS Equivalent, Middle of the Road, and Aggressive renewable energy content scenarios. The generation portion of customers' bills is the only cost component for which the CCA competes with the incumbent utilities. Customer billing and delivery charges (transmission and distribution) are the same for both CCA and IOU bundled customers. Generation rate comparisons are provided for the first five years of the Study period by rate class.[7] The total anticipated bill impact to residential customers in 2020 is included in Table ES 9.

Table ES-6 Generation Rate Comparisons for PG&E, SCE, and CCA, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

	2022		2023		2024		2025		2026	
Rate Class	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**
Agriculture	0.1175	0.0742	0.1175	0.0753	0.1175	0.0749	0.1175	0.0747	0.1175	0.0754
Commercial/Industrial Small <200kW	0.1183	0.1049	0.1183	0.1065	0.1183	0.1059	0.1183	0.1055	0.1183	0.1065
Commercial/Industrial Medium 200<500 kW	0.1190	0.1097	0.1190	0.1113	0.1190	0.1107	0.1190	0.1103	0.1190	0.1114
Commercial/Industrial Large 500<1000 kW	0.1145	0.1107	0.1145	0.1124	0.1145	0.1118	0.1145	0.1114	0.1145	0.1124
Residential	0.1220	0.1003	0.1220	0.1018	0.1220	0.1013	0.1220	0.1009	0.1220	0.1018
Residential CARE	0.1152	0.0936	0.1152	0.0950	0.1152	0.0945	0.1152	0.0941	0.1152	0.0950
Residential Solar Choice	0.1920	0.1265	0.1920	0.1284	0.1920	0.1277	0.1920	0.1272	0.1920	0.1284
Weighted Average	**0.1193**	**0.0961**	**0.1193**	**0.0975**	**0.1193**	**0.0970**	**0.1193**	**0.0967**	**0.1193**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**24.10%**		**22.27%**		**22.92%**		**23.37%**		**22.22%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1050	0.0543	0.1050	0.0551	0.1050	0.0548	0.1050	0.0547	0.1050	0.0552
Commercial/Industrial Small <200kW	0.1072	0.0922	0.1072	0.0936	0.1072	0.0931	0.1072	0.0927	0.1072	0.0936
Commercial/Industrial Medium 200<500 kW	0.1064	0.0837	0.1064	0.0850	0.1064	0.0845	0.1064	0.0842	0.1064	0.0850
Commercial/Industrial Large 500<1000 kW	0.1057	0.0777	0.1057	0.0789	0.1057	0.0785	0.1057	0.0782	0.1057	0.0789
Residential	0.0999	0.0712	0.0999	0.0723	0.0999	0.0719	0.0999	0.0716	0.0999	0.0723
Residential CARE	0.0924	0.0635	0.0924	0.0645	0.0924	0.0641	0.0924	0.0639	0.0924	0.0645
Residential Green Tariff	0.1199	0.1127	0.1199	0.1144	0.1199	0.1138	0.1199	0.1134	0.1199	0.1144
Weighted Average	**0.1034**	**0.0776**	**0.1034**	**0.0788**	**0.1034**	**0.0784**	**0.1034**	**0.0781**	**0.1034**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**33.23%**		**31.26%**		**31.97%**		**32.44%**		**31.21%**

Table ES-7 Generation Rate Comparisons for PG&E, SCE, and CCA, AWG Jurisdictions Middle of the Road Renewable Energy Content Scenario

Rate Class	2022 CCA Rates	2022 PG&E Rates	2023 CCA Rates	2023 PG&E Rates	2024 CCA Rates	2024 PG&E Rates	2025 CCA Rates	2025 PG&E Rates	2026 CCA Rates	2026 PG&E Rates
Agriculture	0.1242	0.0742	0.1242	0.0753	0.1242	0.0749	0.1242	0.0747	0.1242	0.0754
Commercial/Industrial Small <200kW	0.1250	0.1049	0.1250	0.1065	0.1250	0.1059	0.1250	0.1055	0.1250	0.1065
Commercial/Industrial Medium 200<500 kW	0.1257	0.1097	0.1257	0.1113	0.1257	0.1107	0.1257	0.1103	0.1257	0.1114
Commercial/Industrial Large 500<1000 kW	0.1212	0.1107	0.1212	0.1124	0.1212	0.1118	0.1212	0.1114	0.1212	0.1124
Residential	0.1287	0.1003	0.1287	0.1018	0.1287	0.1013	0.1287	0.1009	0.1287	0.1018
Residential CARE	0.1219	0.0936	0.1219	0.0950	0.1219	0.0945	0.1219	0.0941	0.1219	0.0950
Residential Solar Choice	0.1987	0.1265	0.1987	0.1284	0.1987	0.1277	0.1987	0.1272	0.1987	0.1284
Weighted Average	**0.1260**	**0.0961**	**0.1260**	**0.0975**	**0.1260**	**0.0970**	**0.1260**	**0.0967**	**0.1260**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**31.06%**		**29.13%**		**29.82%**		**30.29%**		**29.08%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1117	0.0543	0.1117	0.0551	0.1117	0.0548	0.1117	0.0547	0.1117	0.0552
Commercial/Industrial Small <200kW	0.1139	0.0922	0.1139	0.0936	0.1139	0.0931	0.1139	0.0927	0.1139	0.0936
Commercial/Industrial Medium 200<500 kW	0.1132	0.0837	0.1132	0.0850	0.1132	0.0845	0.1132	0.0842	0.1132	0.0850
Commercial/Industrial Large 500<1000 kW	0.1124	0.0777	0.1124	0.0789	0.1124	0.0785	0.1124	0.0782	0.1124	0.0789
Residential	0.1066	0.0712	0.1066	0.0723	0.1066	0.0719	0.1066	0.0716	0.1066	0.0723
Residential CARE	0.0991	0.0635	0.0991	0.0645	0.0991	0.0641	0.0991	0.0639	0.0991	0.0645
Residential Green Tariff	0.1266	0.1127	0.1266	0.1144	0.1266	0.1138	0.1266	0.1134	0.1266	0.1144
Weighted Average	**0.1102**	**0.0776**	**0.1102**	**0.0788**	**0.1102**	**0.0784**	**0.1102**	**0.0781**	**0.1102**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**41.87%**		**39.78%**		**40.53%**		**41.04%**		**39.72%**

Table ES-8 Generation Rate Comparisons for PG&E, SCE, and CCA, AWG Jurisdictions Aggressive Renewable Energy Content Scenario

Rate Class	2022 CCA Rates	2022 PG&E Rates	2023 CCA Rates	2023 PG&E Rates	2024 CCA Rates	2024 PG&E Rates	2025 CCA Rates	2025 PG&E Rates	2026 CCA Rates	2026 PG&E Rates
Agriculture	0.1382	0.0742	0.1382	0.0753	0.1382	0.0749	0.1382	0.0747	0.1382	0.0754
Commercial/Industrial Small <200kW	0.1390	0.1049	0.1390	0.1065	0.1390	0.1059	0.1390	0.1055	0.1390	0.1065
Commercial/Industrial Medium 200<500 kW	0.1397	0.1097	0.1397	0.1113	0.1397	0.1107	0.1397	0.1103	0.1397	0.1114
Commercial/Industrial Large 500<1000 kW	0.1352	0.1107	0.1352	0.1124	0.1352	0.1118	0.1352	0.1114	0.1352	0.1124
Residential	0.1426	0.1003	0.1426	0.1018	0.1426	0.1013	0.1426	0.1009	0.1426	0.1018
Residential CARE	0.1359	0.0936	0.1359	0.0950	0.1359	0.0945	0.1359	0.0941	0.1359	0.0950
Residential Solar Choice	0.2026	0.1265	0.2026	0.1284	0.2026	0.1277	0.2026	0.1272	0.2026	0.1284
Weighted Average	**0.1399**	**0.0961**	**0.1399**	**0.0975**	**0.1399**	**0.0970**	**0.1399**	**0.0967**	**0.1399**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**45.56%**		**43.41%**		**44.18%**		**44.70%**		**43.35%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1258	0.0543	0.1258	0.0551	0.1258	0.0548	0.1258	0.0547	0.1258	0.0552
Commercial/Industrial Small <200kW	0.1280	0.0922	0.1280	0.0936	0.1280	0.0931	0.1280	0.0927	0.1280	0.0936
Commercial/Industrial Medium 200<500 kW	0.1272	0.0837	0.1272	0.0850	0.1272	0.0845	0.1272	0.0842	0.1272	0.0850
Commercial/Industrial Large 500<1000 kW	0.1265	0.0777	0.1265	0.0789	0.1265	0.0785	0.1265	0.0782	0.1265	0.0789
Residential	0.1208	0.0712	0.1208	0.0723	0.1208	0.0719	0.1208	0.0716	0.1208	0.0723
Residential CARE	0.1132	0.0635	0.1132	0.0645	0.1132	0.0641	0.1132	0.0639	0.1132	0.0645
Residential Green Tariff	0.1308	0.1127	0.1308	0.1144	0.1308	0.1138	0.1308	0.1134	0.1308	0.1144
Weighted Average	**0.1242**	**0.0776**	**0.1242**	**0.0788**	**0.1242**	**0.0784**	**0.1242**	**0.0781**	**0.1242**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**59.94%**		**57.58%**		**58.43%**		**59.00%**		**57.52%**

Figure ES-8 and Figure ES-9 graphically depict the difference in generation rates between the CCA and PG&E and the CCA and SCE, respectively, for the AWG Jurisdictions scenario for the three renewable content scenarios.

Figure ES-8 CCA and PG&E Generation Rate Comparison Summary for AWG Jurisdictions Participation Scenarios

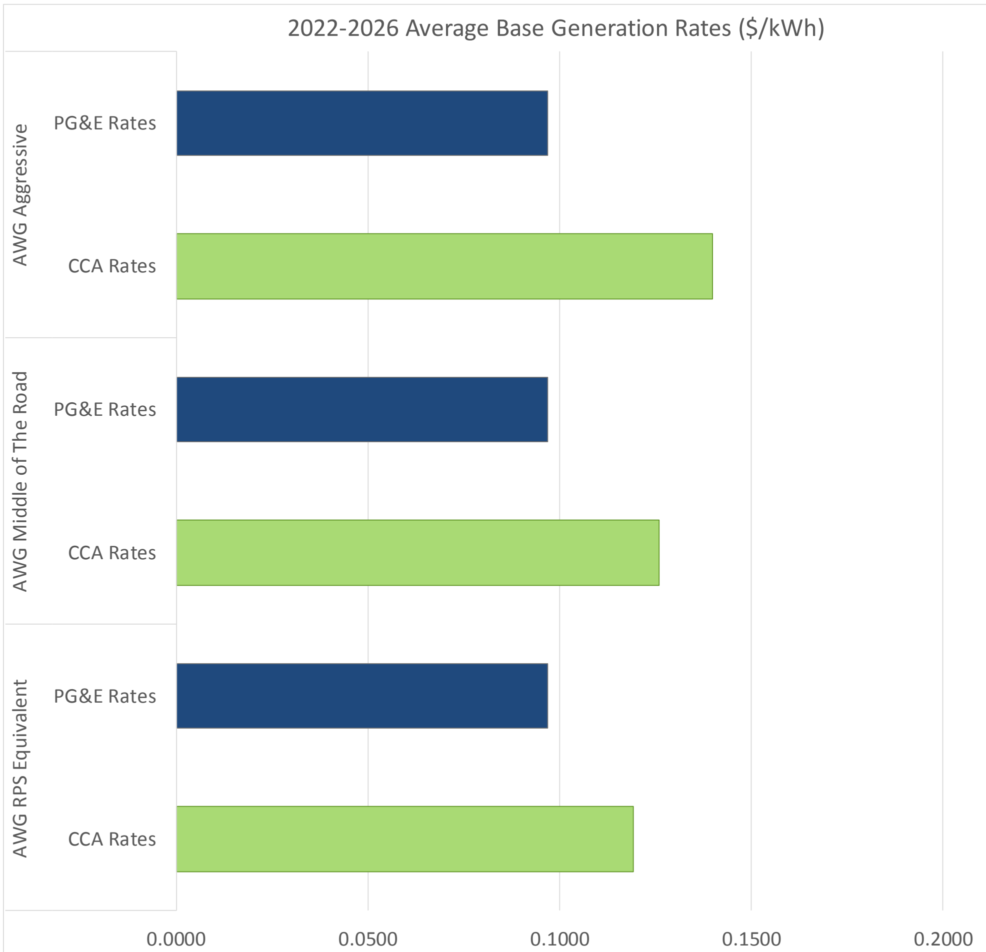


Figure ES-9 CCA and SCE Generation Rate Comparison Summary for AWG Jurisdictions Participation Scenarios

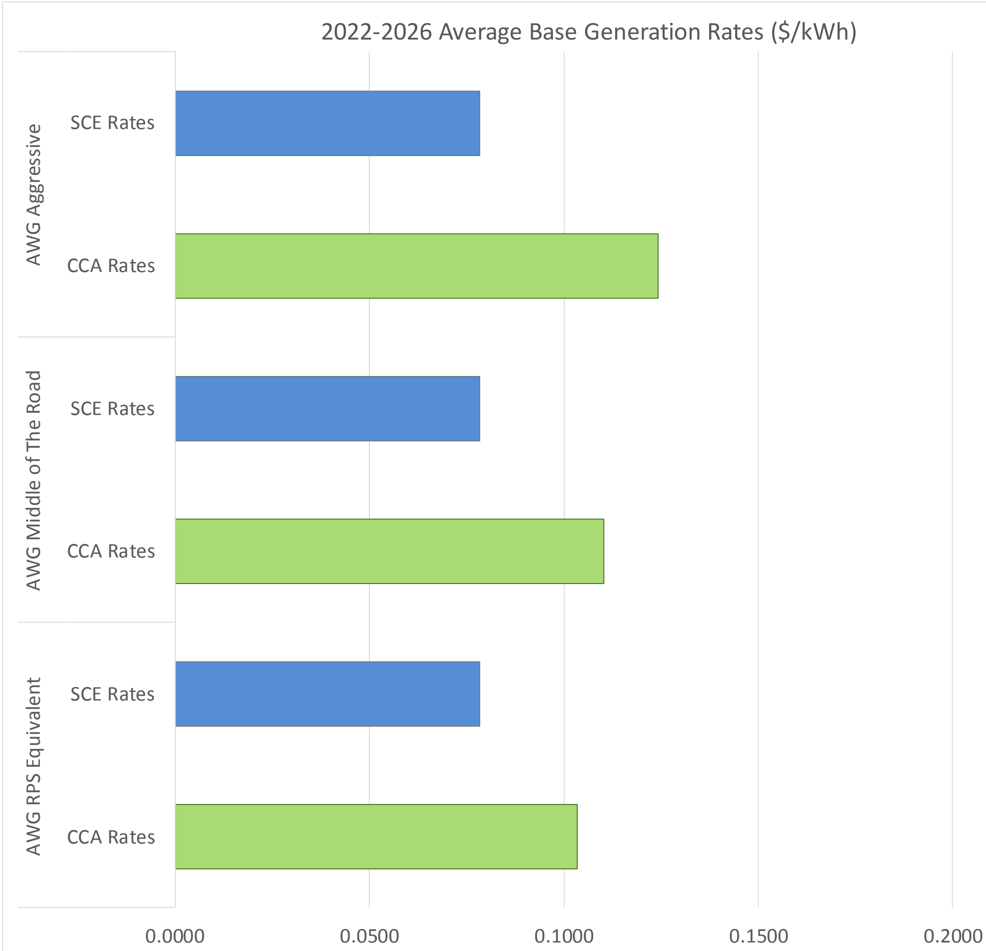


Table ES-9 shows the percentage change in average generation rates and the monetary change in monthly Residential bills for CCA customers versus PG&E and SCE, and the percent change in GHG emissions for all rate classes. This data is presented for year 2020. The previous Tables ES-6 through ES-8 present weighted average rate impacts across all seven customer classes examined for years 2022-2026.

Table ES-9 Summary of Forecasted Residential Class Outcomes by Renewable Energy Content Scenario, AWG Jurisdictions Participation Scenarios, Year 2020

Participation Scenario	Included Jurisdictions	Renewable Energy Content	Pacific Gas & Electric		Southern California Edison		Proportional GHG Comparison
			Generation Rate Comparison (% Increase/ Decrease for CCA Customers)	Monthly Bill Comparison ($ Increase/ Decrease for CCA Customers)	Generation Rate Comparison (% Increase/ Decrease for CCA Customers)	Monthly Bill Comparison ($ Increase/ Decrease for CCA Customers)	
All Tri-County Region	All San Luis Obispo County All Santa Barbara County All Ventura County	RPS Equivalent	22%	$11.25	41%	$14.55	6%
		50%	29%	$14.62	51%	$17.93	-9%
		75%	43%	$21.72	71%	$25.05	-55%
Advisory Working Group Jurisdictions	San Luis Obispo County Santa Barbara County Carpinteria Santa Barbara Ventura County Camarillo Moorpark Ojai Simi Valley Thousand Oaks Ventura	RPS Equivalent	22%	$12.21	41%	$16.08	6%
		50%	29%	$15.92	50%	$19.79	-9%
		75%	43%	$23.68	70%	$27.64	-55%
All San Luis Obispo County	Arroyo Grande Atascadero Grover Beach Morro Bay Paso Robles Pismo Beach San Luis Obispo Unincorporated SLO County	RPS Equivalent	29%	$12.07			7%
		50%	36%	$14.89			-9%
		75%	51%	$20.77			-54%
Unincorporated San Luis Obispo County	Unincorporated SLO County	RPS Equivalent	35%	$15.70			7%
		50%	42%	$18.77			-9%
		75%	56%	$25.21			-54%
All Santa Barbara County	Buellton Carpinteria Goleta Guadalupe Santa Barbara Santa Maria Solvang Unincorporated Santa Barbara County	RPS Equivalent	24%	$11.15	45%	$14.53	7%
		50%	31%	$14.27	55%	$17.69	-9%
		75%	45%	$20.78	75%	$24.22	-55%

Participation Scenario	Included Jurisdictions	Renewable Energy Content	Pacific Gas & Electric		Southern California Edison		Proportional GHG Comparison
			Generation Rate Comparison (% Increase/ Decrease for CCA Customers)	Monthly Bill Comparison ($ Increase/ Decrease for CCA Customers)	Generation Rate Comparison (% Increase/ Decrease for CCA Customers)	Monthly Bill Comparison ($ Increase/ Decrease for CCA Customers)	
Unincorporated Santa Barbara County	Unincorporated Santa Barbara County	RPS Equivalent	26%	$15.08	47%	$19.29	7%
		50%	33%	$18.97	56%	$23.23	-9%
		75%	47%	$27.11	76%	$31.44	-54%
All Ventura County	Camarillo Fillmore Moorpark Ojai Oxnard Port Hueneme Santa Paula Simi Valley Thousand Oaks Ventura Unincorporated Ventura County	RPS Equivalent			41%	$15.87	6%
		50%			50%	$19.54	-10%
		75%			70%	$27.35	-55%
City of Santa Barbara	Santa Barbara	RPS Equivalent			69%	$17.91	6%
		50%			78%	$20.42	-10%
		75%			100%	$25.98	-55%

Table ES-10 shows annual operating results for the AWG Jurisdictions participation scenario for the RPS Equivalent renewable energy content scenario. Net operating margins are negative for all years of the Study period; meaning revenues are not sufficient to cover total operating and non-operating expenses plus the contingency and rate stabilization fund. In the initial years of the study period, this is due to the phasing in of customers and a lag in revenues versus expenditures. In later years, this revenue insufficiency is caused by rates remaining unchanged even though the CCA experiences an increase in operating costs. Rates were not increased because the CCA rate proxies were not competitive with IOU rates from the onset of the Study through 2026. Raising rates would make them less competitive. Although working capital initially is adequate, given the current debt assumptions that include a long-term bond financing in year 2020 of $288 million, starting in year 2024, working capital declines below targeted amounts and continues to decrease. The combination of increasingly negative net margins and a shortage of working capital would indicate the need for a rate increase around year 2026, again which would further harm the CCA program's rate competitiveness relative to the IOUs. Table ES-11 presents this data for the AWG Jurisdictions Middle of the Road renewable energy content scenario and Table ES-12 presents this data for the AWG Jurisdictions Aggressive renewable energy content scenario. Generally speaking, results for these alternate renewable energy content scenarios are similar to the RPS Equivalent scenario, although net margins and working capital deficiencies are better due to the higher rate proxies, which are set at the beginning and remain constant throughout the study period. Rate increases would still be required, but around the 2028 timeframe.

Table ES-10 CCA Annual Operating Results, AWG Jurisdictions RPS Equivalent Scenario

Year	Operating Revenues ($000s)	Total Operating Expenses Plus Contingency/ Rate Stabilization Fund ($000s)	Non-Operating Revenues/ (Expenses) ($000s)	Debt Service ($000s)	Net Margin[1] ($000s)	Working Capital Fund ($000s)	Working Capital Target ($000s)	Working Capital Surplus/ (Deficiency) ($000s)	Working Capital Surplus/ (Deficiency) (%)
	a	b	c	d	a - b + c - d	e	f	e - f	(e/f)-1
2020	110,694	139,109	1,145	11,515	(38,785)	211,653	47,077	164,575	350%
2021	445,293	469,267	2,227	11,515	(33,262)	189,905	159,570	30,335	19%
2022	545,838	533,627	2,046	17,276	(3,018)	186,887	181,993	4,894	3%
2023	556,361	541,735	2,028	17,276	(621)	186,266	184,808	1,458	1%
2024	556,922	543,639	1,925	17,276	(2,067)	184,199	185,916	(1,716)	-1%
2025	555,121	543,720	1,985	17,276	(3,889)	180,310	186,453	(6,143)	-3%
2026	554,190	551,493	1,903	17,276	(12,676)	167,634	189,470	(21,836)	-12%
2027	553,316	556,757	1,721	17,276	(18,995)	148,639	191,885	(43,246)	-23%
2028	553,165	566,687	1,396	17,276	(29,401)	119,238	195,934	(76,697)	-39%
2029	550,808	569,985	1,183	17,276	(35,270)	83,967	198,148	(114,181)	-58%
2030	548,923	581,521	386	17,276	(49,488)	34,479	203,224	(168,745)	-83%
				NPV of Net Margin:	(176,175)				

[1] Net Margin includes Net Operating Income less Debt Service. The net present value (NPV) of the Net Margin is determined using a 4% discount rate and is as of Year 2020. The discount rate is equal to the interest rate on the long-term debt.

Table ES-11 CCA Annual Operating Results, AWG Jurisdictions Middle of the Road Scenario

Year	Operating Revenues ($000s)	Total Operating Expenses Plus Contingency/ Rate Stabilization Fund ($000s)	Non-Operating Revenues/ (Expenses) ($000s)	Debt Service ($000s)	Net Margin[1] ($000s)	Working Capital Fund ($000s)	Working Capital Target ($000s)	Working Capital Surplus/ (Deficiency) ($000s)	Working Capital Surplus/ (Deficiency) (%)
	a	b	c	d	a - b + c - d	e	f	e - f	(e/f)-1
2020	117,525	150,875	1,235	12,330	(44,445)	223,724	50,583	173,141	342%
2021	472,491	504,655	2,323	12,330	(42,170)	193,883	170,117	23,766	14%
2022	579,072	568,848	2,082	18,499	(6,192)	187,691	192,494	(4,803)	-2%
2023	590,222	575,366	2,044	18,499	(1,600)	186,092	194,836	(8,745)	-4%
2024	590,817	570,966	1,962	18,499	3,314	189,406	194,067	(4,662)	-2%
2025	588,906	566,609	2,098	18,499	5,896	195,302	193,284	2,019	1%
2026	587,918	570,586	2,132	18,499	966	196,268	195,171	1,096	1%
2027	586,991	571,282	2,109	18,499	(681)	195,587	196,227	(640)	0%
2028	586,831	576,506	1,991	18,499	(6,182)	189,405	198,875	(9,470)	-5%
2029	584,330	574,978	2,033	18,499	(7,113)	182,292	199,652	(17,361)	-9%
2030	582,330	581,643	1,541	18,499	(16,270)	166,022	203,279	(37,257)	-18%
				NPV of Net Margin:	(100,693)				

[1] Net Margin includes Net Operating Income less Debt Service. The net present value (NPV) of the Net Margin is determined using a 4% discount rate and is as of Year 2020. The discount rate is equal to the interest rate on the long-term debt.

Table ES-12 CCA Annual Operating Results, AWG Jurisdictions Aggressive Scenario

Year	Operating Revenues ($000s)	Total Operating Expenses Plus Contingency/ Rate Stabilization Fund ($000s)	Non-Operating Revenues/ (Expenses) ($000s)	Debt Service ($000s)	Net Margin[1] ($000s)	Working Capital Fund ($000s)	Working Capital Target ($000s)	Working Capital Surplus/ (Deficiency) ($000s)	Working Capital Surplus/ (Deficiency) (%)
	a	b	c	d	a - b + c - d	e	f	e - f	(e/f)-1
2020	131,724	168,193	1,428	13,746	(48,788)	250,176	55,745	194,431	349%
2021	528,600	562,520	2,607	13,746	(45,059)	218,863	187,370	31,493	17%
2022	647,505	633,619	2,361	20,623	(4,375)	214,487	211,809	2,679	1%
2023	659,933	646,015	2,318	20,623	(4,388)	210,100	215,901	(5,801)	-3%
2024	660,598	637,896	2,227	20,623	4,307	214,407	214,025	381	0%
2025	658,462	633,821	2,370	20,623	6,388	220,795	213,325	7,469	4%
2026	657,357	640,581	2,395	20,623	(1,452)	219,343	216,041	3,302	2%
2027	656,320	642,137	2,343	20,623	(4,096)	215,247	217,353	(2,106)	-1%
2028	656,142	648,050	2,187	20,623	(10,344)	204,903	220,206	(15,303)	-7%
2029	653,345	646,843	2,185	20,623	(11,936)	192,967	221,079	(28,111)	-13%
2030	651,109	652,739	1,647	20,623	(20,605)	172,362	224,476	(52,114)	-23%
				NPV of Net Margin:	(120,434)				

[1] Net Margin includes Net Operating Income less Debt Service. The net present value (NPV) of the Net Margin is determined using a 4% discount rate and is as of Year 2020. The discount rate is equal to the interest rate on the long-term debt.

H. Feasibility Outcome Summary

In no participation or renewable energy content scenario were the CCA program's rates competitive with PG&E or SCE. Given the underperformance of the CCA in terms of being rate competitive, consistently having negative net margins, and failing to meet the target for working capital, the CCA under the assumptions used in the Study is neither reliably solvent nor financially feasible.

The two primary factors driving forecasted feasibility results for the CCA include: 1) the competitiveness of CCA rates against PG&E and SCE rates; and 2) the long-term financial viability of the enterprise. Under all participation scenarios, because the rate comparisons show most rate classes paying more for power supplied by the CCA than from the incumbent utilities and because the CCA does not maintain sufficient revenues and working capital throughout the Study period, the CCA is deemed infeasible Regarding rate competitiveness, forecasted CCA revenue requirements are primarily driven by power procurement costs and the Cost Responsibility Surcharge (CRS), which consists of the Competitive Transition Charge (CTC), the Department of Water Resources Bond Charge (DWR-BC), and the Power Cost Indifference Adjustment (PCIA). Together, these two components represent 78% of the total of the overall projected CCA revenue requirement and are thus primary drivers of rate competitiveness against the two incumbent utilities.

Recent historical movements in the CRS and the allocation of incumbent utility revenue requirements between generation and delivery (i.e., transmission and distribution) appear to disadvantage the CCA program. The delivery portion of customers' bills is paid equally by CCA and bundled IOU customers. Generally speaking, in recent years the incumbent utilities appear to have been shifting costs from generation to delivery, as discussed in more detail in Section II.E.1 Feasibility Drivers. The CCA only competes against the incumbent utilities on generation. Given the assumptions of this Study, SCE and PG&E forecasted generation rates are not high enough to support CCA feasibility at the forecasted level of CCA power procurement and operational costs. Regarding long-term financial viability, the CCA would need additional rate increases around the year 2026 timeframe to maintain adequate working capital and increase net margins, further decreasing rate competitiveness.

I. Sensitivity Analysis Results

Upon completion of the Study outcomes for each participation and renewable energy content scenario, additional sensitivity cases were examined against the AWG Jurisdictions participation scenario to determine how changes in key inputs affect feasibility outcomes. These sensitivities included: (1) Decreases in power procurement costs; (2) Increases in IOU rate escalation; and (3) Decreases in staffing costs. Each sensitivity was examined individually to determine the point at which the CCA could be feasible. As discussed in more detail in Section II.E.2, Pro Forma Sensitivity Analysis, in order for the CCA to be feasible:

- Power procurement costs would have to decrease 40% over the Study forecast, or
- PG&E and SCE rates would have to escalate at an additional 4.0% per year above the Study forecast.

A staffing cost reduction alone is not expected to affect program feasibility. Although not examined as part of this Study, some combination of changes to the Study assumptions could result in a more feasible outcome. Like all feasibility studies, assumptions used herein are based on a forecast of future conditions which may or may not occur. Various market and regulatory drivers may change resulting in different outcomes from those assumed herein. The assumptions used in the Study are reasonable for the purposes of analyzing the feasibility of CCA within the Tri-County Region, but no warranties as to the accuracy of outcomes are implied or should be inferred.

I. Introduction

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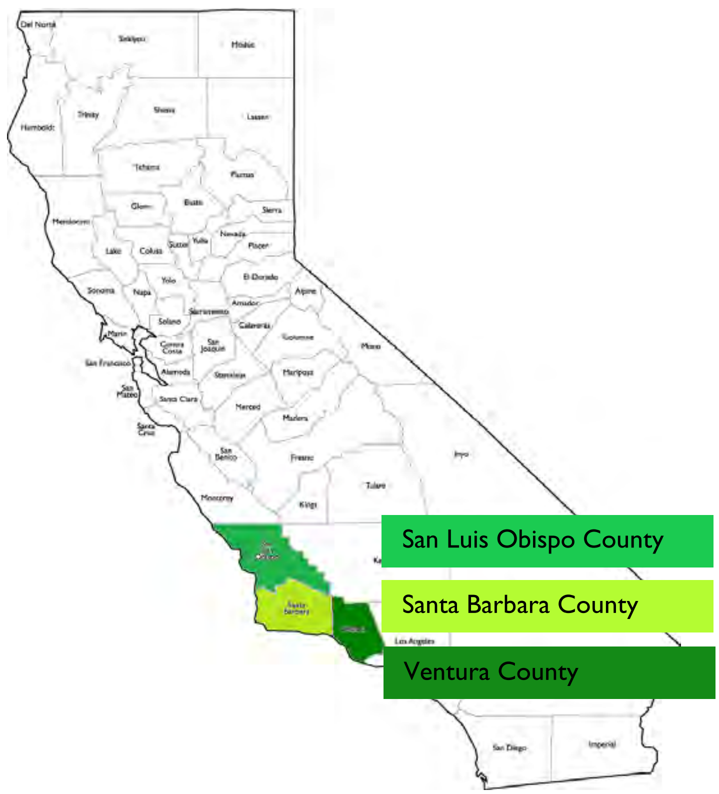
I. Introduction

This technical feasibility study (Study) was conducted to provide the County of Santa Barbara and other jurisdictions across San Luis Obispo, Santa Barbara, and Ventura Counties (Tri-County) the information needed to understand the feasibility of forming a community choice aggregation (CCA) program for the Tri-County Region (shown in Figure 1). The Study is in part motivated by the County of Santa Barbara's Energy and Climate Action Plan and the climate action plans of other local government that view CCA as a way to help meet local greenhouse gas (GHG) reduction goals and other objectives including economic development and local control over electricity supply.

The County of Santa Barbara Board of Supervisors authorized the funding needed to complete this Study in June 2015 and directed staff to explore regional interest in CCA. Ten local governments joined with the County of Santa Barbara to fund the Study.[8] The following jurisdictions formed an Advisory Working Group (AWG) in December 2015:

- Unincorporated San Luis Obispo County
- Unincorporated Santa Barbara County, plus:
    - o City of Carpinteria
    - o City of Santa Barbara
- Unincorporated Ventura County, plus:
    - o City of Camarillo
    - o City of Moorpark
    - o City of Ojai
    - o City of Simi Valley
    - o City of Thousand Oaks
    - o City of Ventura

Figure 1 Map of Participating California Counties



Collectively, the Advisory Working Group has named the potential CCA: Central Coast Power. This Study includes an overview of the necessary steps to implement Central Coast Power in the event that the Study demonstrates a positive outcome. In addition, the Study evaluates eight participation scenarios comprised of different jurisdictions within the Tri-County Region, as well as three different renewable energy content scenarios for Central Coast Power's supply portfolio.

A. Study Purpose

The purpose of this feasibility Study is to advise and guide the Tri-County Region in understanding the feasibility of forming a CCA program and explain required startup and operational processes. This Study evaluates eight jurisdictional participation scenarios and, for each, three renewable power content scenarios to determine whether a CCA program in the Tri-County Region is a) financially feasible; and b) will meet its stated policy objectives.

The Advisory Working Group established the following CCA program objectives, requirements, and constraints.

Program Objectives:

1. Establish a financially sustainable CCA that is responsive to the priorities of participating jurisdictions, is well managed, and enables local control.
2. Provide electricity rates that are competitive with those offered by incumbent utilities for similar products.
3. Offer customers greater choice over how their electricity is sourced and in which differentiated energy options they may voluntarily participate.
4. Develop a supply portfolio with lower GHG emissions than produced by incumbent utilities and that supports the achievement of local climate action plan emission reduction goals.
5. Establish a supply portfolio that prioritizes the use and development of local and in-state renewable resources and minimizes the use of unbundled renewable energy credits.
6. Promote a supply portfolio that incorporates energy efficiency and demand response programs, has aggressive reduced consumption goals, and effectively manages public goods charge revenues to offer local services.
7. Demonstrate quantifiable economic benefits to the region (e.g., local workforce development, new energy programs, and increased local energy investments).

Program Requirements:

- Default rates must be competitive with the incumbent utilities: Southern California Edison (SCE) and Pacific Gas and Electric (PG&E).
- All supply scenarios must meet or exceed the state's Renewable Portfolio Standard (RPS).
- Customers located in SCE and PG&E territories must have access to the same Central Coast Power supply content and product/program offerings.
- The Study must inform policy makers how customers may be impacted on comparable rates (i.e., average over period of time).

Program Constraints:

- No differentiated coal generation in power purchase agreements.
- Santa Barbara County cannot serve customers in only one of the two utility territories.

B. Study Scope

This Study looks at electricity usage and supply for an eleven-year period from 2020 to 2030, although a potential CCA program could begin earlier than 2020. Customer electricity usage and the cost of power supply were forecasted as the foundation for determining feasibility, as described in the Technical and Financial Analysis, Section II. This Study Scope Section defines the jurisdictional participation and renewable energy content scenarios used in the Study.

B.1. Jurisdictional Participation Scenarios

Given the uniqueness of multiple municipalities partnering to commission this feasibility Study, the Advisory Working Group established eight geographic participation scenarios. These eight scenarios were selected to better understand the feasibility of different sizes and configurations of CCA programs and the associated effect of customer demographics. Although the entire Tri-County Region may not pursue CCA, certain jurisdictions may decide to move forward with CCA. Table 1 outlines the cities and counties included in each of the eight participation scenarios. For the purposes of this report and for the sake of brevity, only the AWG Jurisdictions scenario is discussed in full within the body of the report. The additional geographic participation scenarios can be found in the appendices noted in Table 1 and included in a separate document.

Table 1 Jurisdictions within Each Participation Scenario

Participation Scenario	Included Jurisdictions		Scenario Location
All Tri-County Region ("Tri-County")	All San Luis Obispo County All Santa Barbara County All Ventura County		Appendix C
Advisory Working Group Jurisdictions ("AWG Jurisdictions")	Unincorporated San Luis Obispo County Unincorporated Santa Barbara County Carpinteria Santa Barbara	Unincorporated Ventura County Camarillo Moorpark Ojai Simi Valley Thousand Oaks Ventura	Main body of this report and Appendix D
All San Luis Obispo County ("All SLO County")	Arroyo Grande Atascadero Grover Beach Morro Bay	Paso Robles Pismo Beach San Luis Obispo Unincorporated SLO County	Appendix E
Unincorporated San Luis Obispo County ("Uninc. SLO County")	Unincorporated SLO County		Appendix F
All Santa Barbara County ("All SB County")	Buellton Carpinteria Goleta Guadalupe Santa Barbara	Santa Maria Solvang Unincorporated Santa Barbara County	Appendix G
Unincorporated Santa Barbara County ("Uninc. SB County")	Unincorporated Santa Barbara County		Appendix H

Participation Scenario	Included Jurisdictions		Scenario Location
All Ventura County ("All Ventura County")	Camarillo Fillmore Moorpark Ojai Oxnard Port Hueneme	Santa Paula Simi Valley Thousand Oaks Ventura Unincorporated Ventura County	Appendix I
City of Santa Barbara ("SB City")	City of Santa Barbara		Appendix J

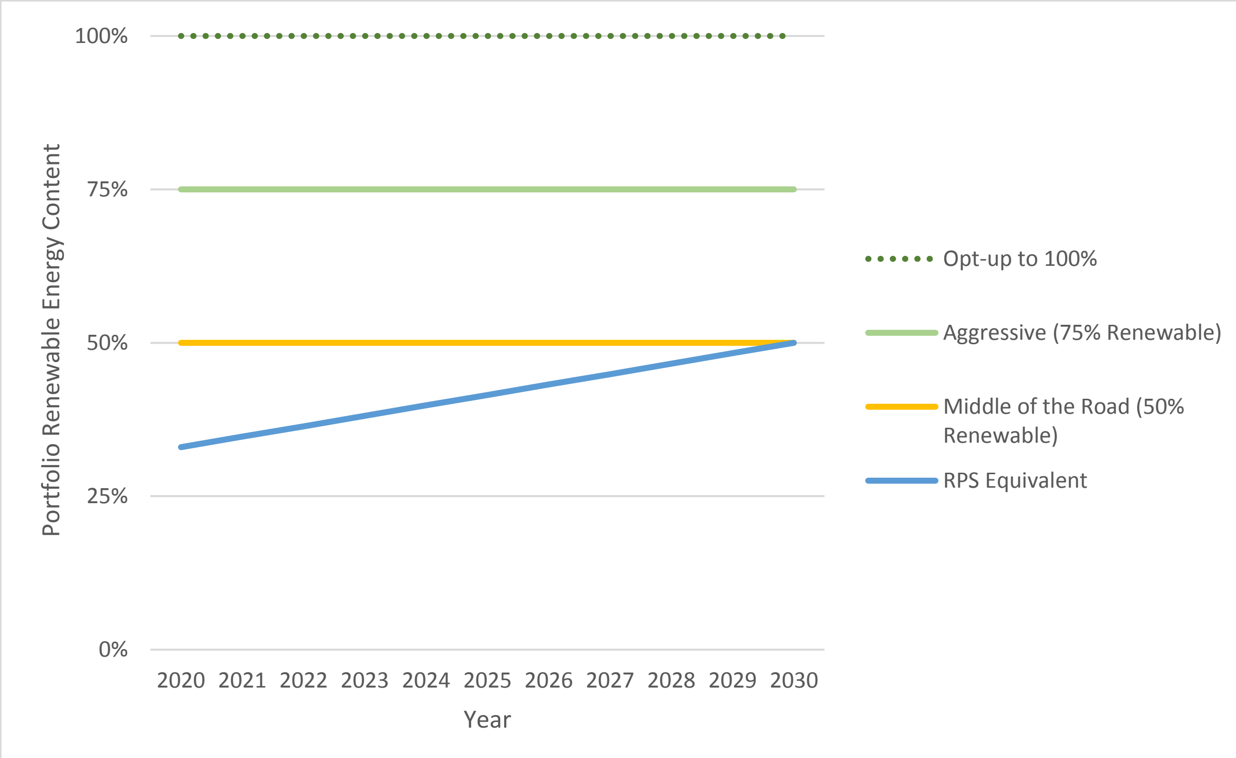
B.2. Renewable Energy Content Scenarios

In addition to the eight participation scenarios described in Table 1, three renewable energy content scenarios were considered, each of which includes a customer option to opt-up to a 100% renewable energy product. For the purposes of this Study, 2% of customers were assumed to opt-up to the 100% renewable option.[9] The three renewable energy content scenarios are as follows:

- **RPS Equivalent**: This scenario assumes that Central Coast Power would offer its base electricity product to all customers starting at 33% renewable content in 2020 and ramping up to 50% renewable content by 2030 in alignment with the California minimum RPS.[10]
- **Middle of the Road**: This scenario assumes that Central Coast Power would offer its base electricity product to all customers using 50% renewable generation supply content for the entire Study period.
- **Aggressive**: This scenario assumes that Central Coast Power would offer its base electricity product to all customers using 75% renewable generation supply content for the entire Study period.

Figure 2 illustrates how the renewable energy content in the RPS Equivalent scenario grows over time, while remaining constant across the Study period in the other two scenarios.

Figure 2 Renewable Energy Content Modeled in this Study



These three renewable supply scenarios were chosen to appropriately illustrate the relative differences in cost for increasing levels of renewable content. While these three scenarios adequately bound potential outcomes for the eleven-year Study time frame, in reality the CCA may progressively increase renewable content over time based on cost competitiveness. For example, Central Coast Power CCA may launch in 2020 with 50% renewable content and progress to 75% renewable content by 2030, if it can do so at a competitive cost.

C. Overview of Electric Supply and Distribution Business Structures

In California, the entity that provides electricity to customers is commonly known as a Load Serving Entity (LSE). An LSE may or may not own the transmission and/or distribution infrastructure ("poles and wires") required to deliver energy to customers. California residents and businesses receive electricity from several different types of electric utilities:[11]

- Rural Electricity Co-operative (Co-op):[12] A Co-op typically serves rural areas, is owned by customers (public), and managed by a board of directors or oversight committee comprised of co-op members and staff. Co-ops may have preferential rights to often low-cost allocations of Federal power from sources like Western Area Power Administration (referred to as "preference power"). Key Attributes: owns distribution; manages energy supply portfolio; and does not allow CCAs or Electricity Service Providers (ESPs)

- Publicly Owned Utility (aka, municipal or consumer owned): A public utility serves the local jurisdiction, is managed by the municipal government, and may be overseen by an elected or appointed board of directors, or the city or county board, council or commission. Public utilities may have preferential rights to often low-cost allocations of Federal or state power from sources like Western Area Power Administration or California Department of Water Resources. Key Attributes: may own generation; owns distribution/transmission; manages energy supply portfolio; and does not allow CCAs or ESPs

- Irrigation District: An Irrigation District has electric supply from hydro projects built to deliver water. Irrigation Districts often transact exclusively in wholesale markets, but some have a retail customer base (e.g., Imperial, Modesto, and Turlock Irrigation Districts). Key Attributes: owns distribution; provides distribution delivery services; manages energy supply portfolio; and allows CCAs and ESPs

- Investor-Owned Utility (IOU): An IOU is a publicly traded corporation with a franchise agreement with the local jurisdiction to provide electric service. An IOU in California is overseen by the California Public Utilities Commission (CPUC). Key Attributes: owns transmission and distribution infrastructure; provides distribution delivery services; manages energy supply portfolio; and allows ESPs and CCAs

- Electricity Service Provider:[13] ESPs were created by the California Electric Utility Industry Restructuring Act, Assembly Bill (AB) 1890, to introduce competition for IOUs in electricity supply.[14] ESPs sell electricity to customers through Direct Access (DA). ESPs are privately held, and generally do not own generation.[15] Key Attributes: does not own distribution infrastructure and manages energy supply portfolio

- Community Choice Aggregator: In 2002, AB 117 allowed cities and counties in IOU territories to become the electricity commodity supplier for jurisdictional customers. Customers have the option to continue service with their IOU or existing ESP, or opt to receive energy from the CCA. Key Attributes: does not own distribution infrastructure; manages energy supply portfolio; and may develop and own generation resources, including renewable resources

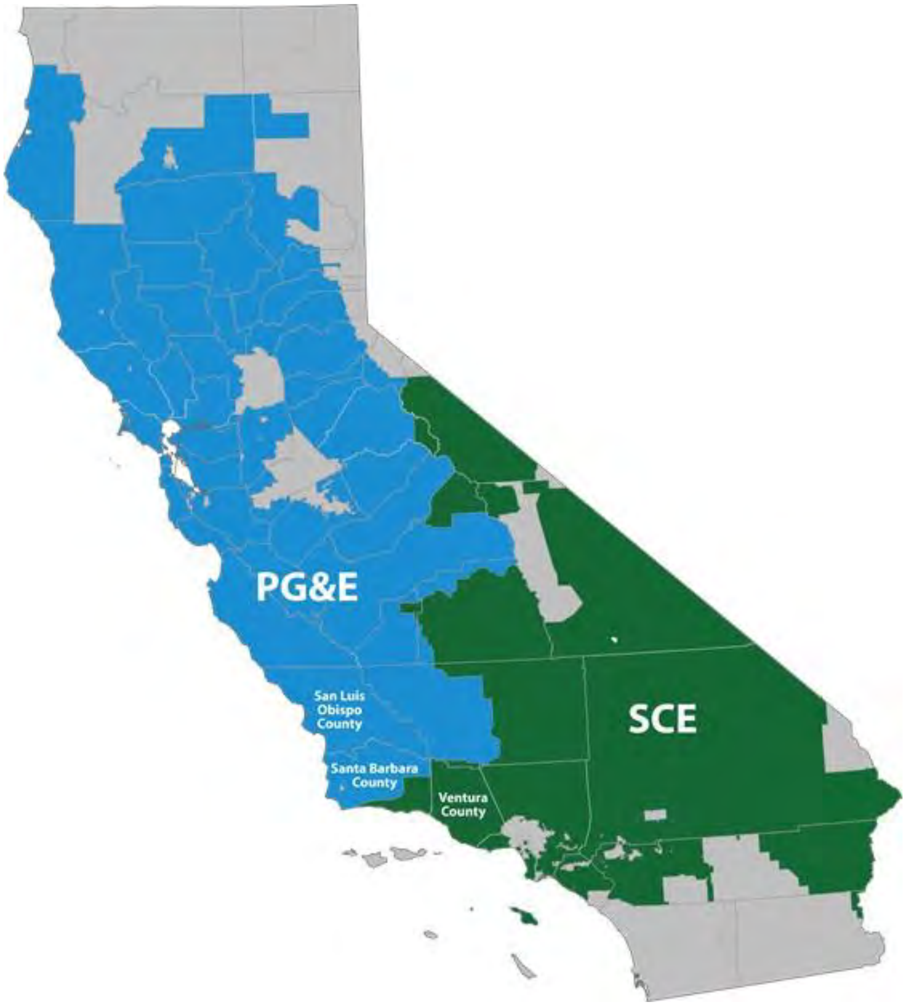
Table 2 summarizes the key attributes of each utility type discussed above. Pertinent to this Study, CCAs afford customers in the jurisdiction energy supply choice and rely on the IOU to deliver the power.[16]

Table 2 Summary of Key Attributes by Utility Type

Utility Type		Rural Cooperative	Public	Irrigation District	Investor Owned	Electricity Service Provider	Community Choice Aggregator
Owner		Customers	Customers	Customers	Shareholders	Private	Customers
Control		Board	City/County Commission, Council, Board	Board	Board	CEO	Board, Council, Commission
Activities	**Generation**		X	X	X		X
	Manage Supply	X	X	X	X	X	X
	Distribution/ Transmission	X	X	X	X		
Allow CCA or ESP				X	X		

SCE and PG&E, the IOUs serving the Tri-County Region, are two of the largest IOUs in the country, by both customer count and electricity load. Figure 3[17] shows that these two utilities cover much of the state of California and all of the territory under consideration for this Study. Lompoc, a city within the County of Santa Barbara that has municipalized its electricity service, is not included in this Study.

Figure 3 Map of Electric IOUs in California



PG&E generally serves the central to northern region of California, while SCE serves the central to southern region of California, except for the San Diego area. PG&E serves all of San Luis Obispo County and the northern portion of Santa Barbara County, while SCE serves the southern end of Santa Barbara County and all of Ventura County. A CCA program that includes Santa Barbara County would be unique as it would cover two IOU service territories[18] and may present additional challenges, as discussed in in Section I.F.

DA customers receive electricity from ESPs, constitute approximately 12% of energy use in the Tri-County Region, and consist mostly of large commercial companies. DA customers pay PG&E or SCE for the delivery of electricity to their premises through specific DA rate tariffs, similar to those for CCAs.[19]

D. Overview of CCA

According to a recent en banc background paper from the CPUC, "CCAs are governmental entities formed by cities and counties to procure electricity for their residents, businesses, and municipal facilities. CCA programs have several unique characteristics. When a CCA launches, IOU electricity customers in the designated service area are automatically opted-in to CCA service, and have to opt out to continue to be served by the IOU. Once established, a CCA purchases power for its customers. The procurement rates are not regulated by the CPUC and instead are regulated by the CCA following its own public process. While the CCA is responsible for procurement, the IOU still provides other services such as transmission, distribution, metering, billing, collection, and customer service."[20]

The primary responsibility of a CCA, and any LSE, is to manage power purchases to serve varying customer demand for electricity.[21] Supplying cost-effective, reliable electric power to customers involves a variety of functions and business processes, which are discussed in more detail in Section II.B.

D.1. CCA History

CCAs were authorized in 2002 by AB 117[22] with additional details codified in California Public Utilities Code Section 366.2(c)(3).[23] AB 117 *"authoriz(ed) customers to aggregate their electrical loads as members of their local community with community choice aggregators."* CPUC Section 366.2(c)(3) provided additional guidance for regulatory oversight provided by the CPUC.

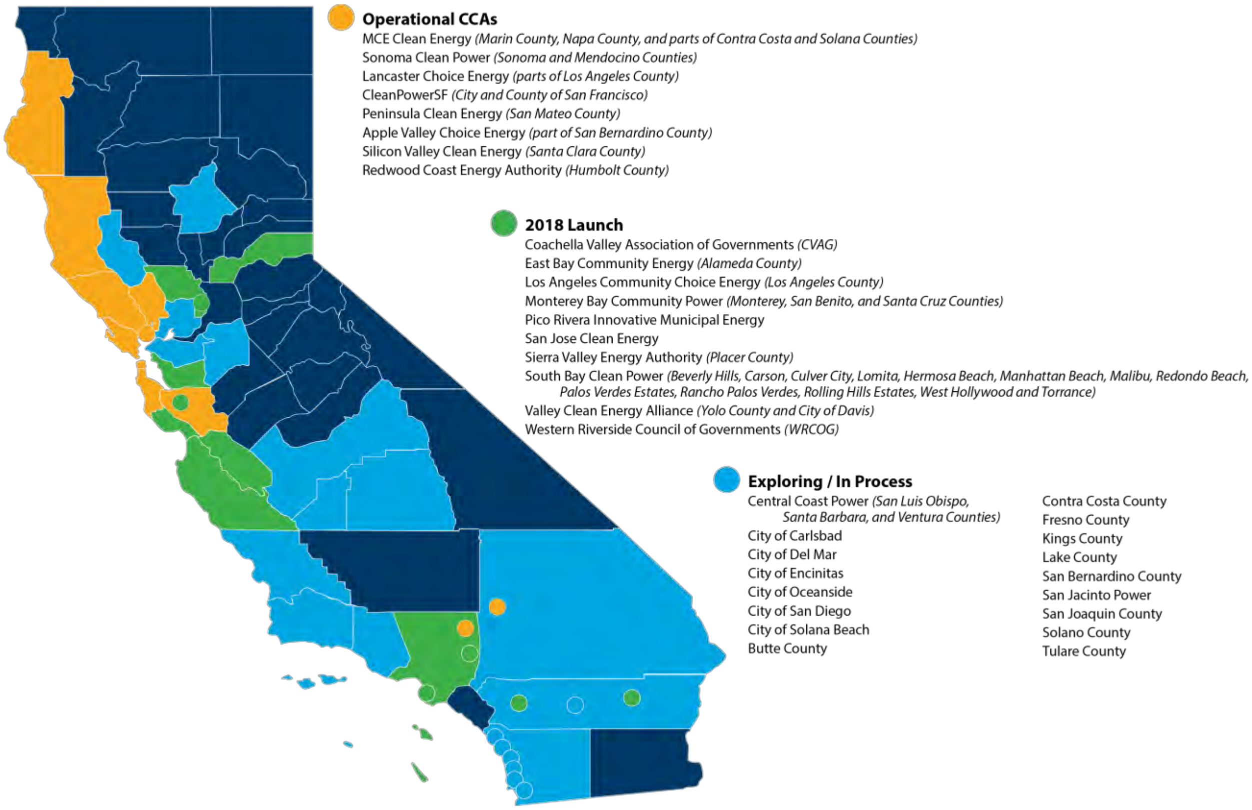
On April 30, 2007, the CPUC authorized its first CCA application submitted by the Kings River Conservation District on behalf of the San Joaquin Valley Power Authority. However, the CCA never launched. In 2010, MCE Clean Energy (MCE)—formerly Marin Clean Energy—became the first operational CCA.

Currently, there are eight operational CCAs:

- MCE Clean Energy[24]
- Sonoma Clean Power[25]
- Lancaster Choice Energy (LCE)[26]
- Clean Power San Francisco[27]
- Peninsula Clean Energy[28]
- Apple Valley Choice Energy
- Silicon Valley Clean Energy
- Redwood Coast Energy Authority

Figure 4 provides a map of CCA activity and exploration in California. CPUC activity with respect to CCAs is likely to pick up as more communities chose to form CCAs.

Figure 4 CCA Activity in California



Recently, the number of municipalities exploring CCA prompted the CPUC to contemplate potential regulatory and policy changes. Within its en banc background paper on CCA,[29] the CPUC also lays out concerns centered on the large number of communities at various stages of CCA exploration. The scale of potential changes is illustrated by Los Angeles Community Choice Energy, which could include 30% of SCE's retail electricity sales.[30] Additionally, the Inland Choice Power CCA Business Plan,[31] completed in December 2016, indicates it could be equivalent to 30% of SCE's retail electricity sales. More information on the current regulatory considerations affecting a potential Central Coast Power CCA can be found in Appendix B. Monterey Bay Community Power comprised of Monterey, San Benito and Santa Cruz Counties also plans to begin service in 2018.[32]

D.2. Potential Benefits of CCA

The Tri-County Region has commissioned this feasibility Study because of the potential benefits associated with a CCA. Chiefly, the benefits of a CCA are as follows:

- Local control for the jurisdiction to pursue the activities and programs that are most important to their constituent customers;
- Increases use of renewable generation;
- Local economic development; and
- Competitive rates with incumbent IOUs.

Each of the three counties included in this Study has some form of a climate action plan. In 2015, the

County of Santa Barbara established an Energy and Climate Action Plan with a focus "to take immediate, cost-effective and coordinated steps to reduce the County's collective GHG emissions." [33] In 2011, the County of Ventura established its Climate Protection Plan, which aimed to reduce emissions from county government operations 15% from baseline levels by 2020.[34] Similarly, the County of San Luis Obispo established an EnergyWise Plan in November of 2011, which established a roadmap to achieving 15% GHG reduction targets from baseline levels by 2020.[35]

One goal for the CCA program is to achieve "an electric supply portfolio with lower GHG emissions than produced by the IOUs and that supports the achievement of local Climate Action Plan emission reduction goals." The activities of the CCA must balance policy goals, such as greenhouse gas reduction targets, with the potential local economic development associated with the investment and operation of the CCA. The benefits of more locally tailored programs related to CCA would need to be compared with the processes and programs already established by the IOUs serving the region.

E. Current IOU Renewable Energy Content and State Mandates

One goal for establishing a CCA program is to increase the level of renewable energy used to serve jurisdictional customers over that supplied by the IOU. This section presents the estimated renewable content for the IOUs and discusses future changes resulting from state mandates.

Table 3 shows the 2015 power content labels for both PG&E and SCE. These labels indicate the generation mix that actually served the territories in 2015. As discussed below, the generation mix displayed here is not stagnant; both IOUs are actively engaged in procuring a resource mix consisting of more renewable generation. As evidenced in Table 3, both PG&E and SCE served customer load using at least 25% renewable resources in 2015, exceeding the California RPS requirement of 23.3% for 2015.[36]

Table 3 2015 SCE and PG&E Power Content Labels[37]

2015 POWER CONTENT LABEL

ENERGY RESOURCES	Power Mix	2015 CA Total Mix**
Eligible Renewable	**25%**	**22%**
Biomass & biowaste	1%	3%
Geothermal	9%	4%
Eligible hydroelectric	0%	1%
Solar	7%	6%
Wind	8%	8%
Coal	**0%**	**6%**
Large Hydroelectric	**2%**	**5%**
Natural Gas	**26%**	**44%**
Nuclear	**6%**	**9%**
Other	**0%**	**0%**
Unspecified sources of power*	**41%**	**14%**
TOTAL	**100%**	**100%**

* "Unspecified sources of power" means electricity from transactions that are not traceable to specific generation sources.

** Percentages are estimated annually by the California Energy Commission based on the electricity sold to California consumers during the previous year.

For specific information about this electricity product, contact: **Southern California Edison** 1-800-655-4555

For general information about the Power Content Label, consult: California Energy Commission 1-844-217-4925 http://www.energy.ca.gov/pcl/

2015 POWER CONTENT LABEL

ENERGY RESOURCES	Power Mix	2015 CA Total Mix**
Eligible Renewable	**30%**	**22%**
Biomass & biowaste	4%	3%
Geothermal	5%	4%
Eligible hydroelectric	1%	1%
Solar	11%	6%
Wind	8%	8%
Coal	**0%**	**6%**
Large Hydroelectric	**6%**	**5%**
Natural Gas	**25%**	**44%**
Nuclear	**23%**	**9%**
Other	**0%**	**0%**
Unspecified sources of power*	**17%**	**14%**
TOTAL	**100%**	**100%**

* "Unspecified sources of power" means electricity from transactions that are not traceable to specific generation sources.

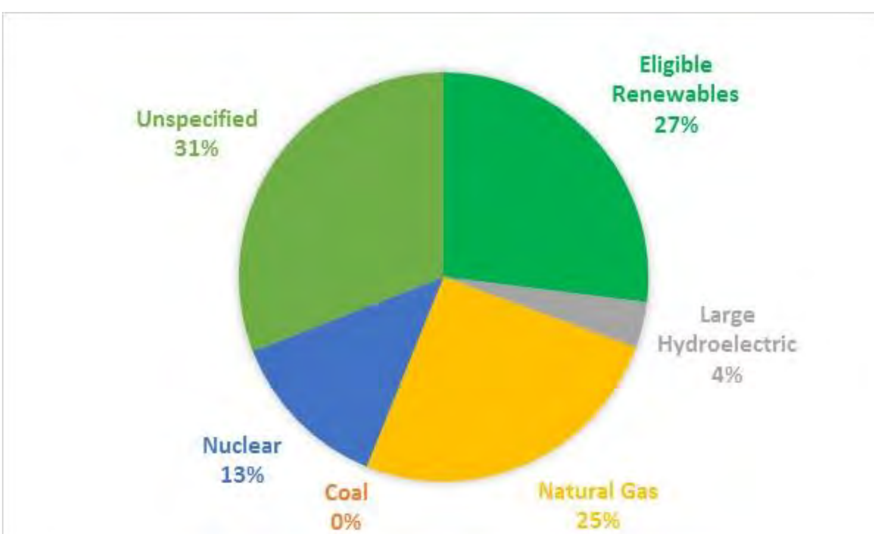
** Percentages are estimated annually by the California Energy Commission based on the electricity sold to California consumers during the previous year.

For specific information about this electricity product, contact: **Pacific Gas and Electric** 415-973-0640

For general information about the Power Content Label, consult: California Energy Commission 1-844-217-4925 http://www.energy.ca.gov/pcl/

Figure 5 applies the renewable energy percentages shown in Table 3 to the electricity consumed by the jurisdictions included in the AWG Jurisdictions scenario—where 71% of electricity usage is served by SCE and 29% by PG&E.[38] Unspecified sources likely consist mostly of generation purchased through the California Independent System Operator (CAISO). The CAISO generation mix for all participating LSEs includes an undifferentiated mix of renewables, hydroelectric, natural gas, nuclear, and imported resources. Therefore, the amount of renewable energy in the actual generation mix is likely higher than the 27% displayed here, but renewable content cannot be more accurately determined.

Figure 5 Generation Mix for the Advisory Working Group Jurisdictions in 2015



The California RPS, was first established for IOUs in 2002 under Senate Bill 1078 and later expanded to other LSEs (such as CCAs, ESPs and public power).[39] The current standard requires all LSEs to procure eligible renewable energy resources totaling 33% of total procurement by 2020 and 50% by 2030.[40] Both PG&E and SCE have exceeded the 2014 and 2015 RPS requirements. Based on CPUC reports, [41] PG&E and SCE have power purchase agreements (PPAs) and resources in place to exceed the 2020 RPS requirement of 33% in 2020 with 43% and 41.4%, respectively, as illustrated in Table 4.[42] For comparison, the 2016 national average generation supply portfolio included only 8.4% renewables.[43]

Table 4 California Renewable Portfolio Standard Requirements and PG&E and SCE RPS Status

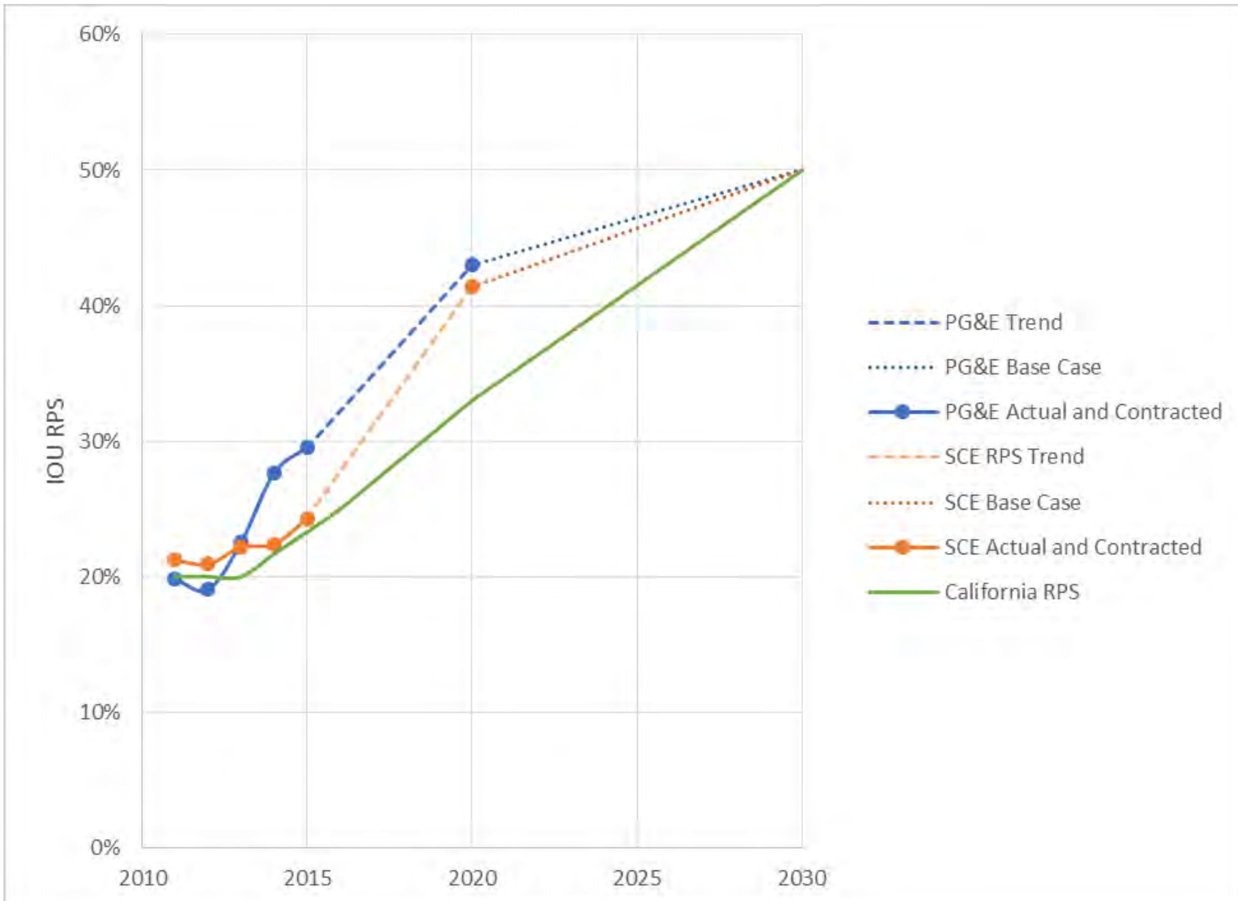
Year	RPS Requirement	PG&E Status	SCE Status
2014	21.7%	27.6%[44]	22.4%[45]
2015	23.3%	29.5%	24.3%
2016	25.0%	unknown	unknown
2017	27.0%	unknown	unknown
2018	29.0%	unknown	unknown
2019	31.0%	unknown	unknown
2020	33.0%	43.0%	41.4%
2030	50.0%	unknown	unknown

This Study covers the period 2020-2030; therefore, an assumption of the rate at which the IOUs will increase renewable content to achieve future RPS targets must be made. This Study incorporates the following IOU renewable portfolio growth rate scenario:

> IOU Base Case: The IOUs will grow their renewable portfolio from 2020 levels to the 50% target following a simple straight line growth rate between 2020 and 2030, as illustrated in Figure 6.

The RPS requirements may change as California is currently considering Senate Bill 100, which would increase the renewable energy mandate to: 50% by December 31, 2026 and 60% by December 31, 2030.[46] PG&E has submitted a joint proposal to decommission the El Diablo nuclear power station and voluntarily reach 55% RPS by 2030.[47]

Figure 6 PG&E and SCE RPS Forecasts



The IOUs are on pace to achieve the 50% RPS target before 2025. To the extent that any additional renewables are added to the IOU portfolios by 2020, the extrapolated rate curves become steeper and the 50% standard may be achieved sooner. In particular, based on the information presented above, the RPS Equivalent renewable energy content scenario modeled here would result in the CCA having less renewable resources than the alternative IOU supply portfolio. At the time the Study scenarios were defined, this information was not known. The level of renewables in the IOU portfolio will impact CCA procurement decisions over time. For example, the CCA may choose to increase the amount of electricity that comes from renewable and/or carbon-free resources based on changes in IOU portfolios.

F. Potential External Risks of CCA

Ultimately, the operational and associated power procurement risks must be managed by the CCA. Risks specific to operational strategies are discussed in Section II Technical and Financial Analysis and in Section IV Conclusions and Recommendation. However, external factors could adversely impact the economics of the CCA despite any and all risk mitigation efforts. External risks for Central Coast Power CCA include:

- Changes in the CCA regulatory and legislative landscape;
- Exit fees and other non-bypassable charges that transfer costs from the IOUs to CCA customers;
- Customer opt-outs and other reductions in energy sales; and

- Variability of renewable generation resources—both supply resources for the CCA, and customer-owned distributed generation (DG) resources.

Recognizing, evaluating, and monitoring these external factors must be a priority within any CCA governance framework, alongside the more traditional operational and market risk management functions associated with managing a supply portfolio with customer service responsibilities. A more thorough discussion of these risks, as well as possible steps to mitigate these risks, can be found in Appendix B.

Additionally, the large hydroelectric generation resources owned and managed by the IOUs were not significantly utilized during the recent drought years through 2016. With the rainfall in the winter of 2016-2017, the hydroelectric reservoirs have filled which enables a low-cost carbon-neutral generation component for the IOUs. In addition, pumped hydro energy storage can help balance the variability of other sources of renewable generation. However, future rainfall and drought conditions are unknown and therefore the future utilization of large hydroelectric generation by the IOUs is unknown. Generally speaking, all other things being equal, increased hydro production will lower IOU generation revenue requirements and have a dampening effect on customer rates. Unless the CCA also has access to this relatively low cost power source, increased hydro production will make it more difficult for the CCA to be rate competitive.

G. Approach to CCA Feasibility

This section discusses the core approach to conducting this Study and presents additional Study assumptions not covered elsewhere in this report.

G.1. Approach Overview

Given that power procurement costs represent the greatest cost and risk to the CCA program, the Study conducted for Central Coast Power assessed in detail the economics of power supply and demand given the variability and uncertainty of power markets. This approach mirrors the responsibilities of a CCA in managing the energy supply portfolio.

The statistical sensitivity analysis used in this Study incorporated specific hourly variability in CAISO locational marginal price nodes in the Tri-County Region, rather than simply evaluating average CAISO pricing. In contrast, other CCA feasibility studies have used fundamentally different approaches that may fail to capture the significant potential misalignment of solar power generation with demand, smoothing over the risk and variability inherently involved with exposure to the CAISO market. For example, actual CAISO real-time market prices from 2014-October 2016 for the Tri-County region averaged $36 per Megawatt-hour (MWh), but varied from a high of $4,377 per MWh to a low of -$1,277/MWh. Negative CAISO pricing occurs when the generation supply exceeds demand, and CAISO will pay participants to increase electricity demand or shut down power production. A CCA feasibility study that relied upon the average market price of $36/MWh would fail to capture the CCA's actual significant exposure to both the up and down sides of the market.

Another important aspect of variability and uncertainty impacting CCA feasibility is the proliferation of customer-owned distributed energy resources (DER). DER reduce the electric load served by an LSE and the associated revenue. In addition, net metering[48] rate structures associated with DER alter revenue recovery from these customers. In addition to declining energy sales for the LSE, DER resources increase the variability of the electricity load forecast and LSE exposure to CAISO market prices. This Study attempts to model these dynamics within the Monte Carlo statistical sensitivity analysis.

The cost of natural gas generation is an additional significant underlying assumption for this Study. Natural gas generation is the major non-RPS-eligible source of power in California. Other CCA feasibility studies have forecasted the cost of natural gas generation to increase by 3.5% annually. However, improved commodity prices, related to the practice of fracking,[49] and improved generation efficiency (measured by heat rate) have reduced natural gas costs. This Study forecasts costs associated with natural gas to continue this decreasing trend over the Study period.

Another unique aspect of this feasibility approach relates to possible CCA renewable power procurement scenarios. Some CCA studies have included procurement scenarios of 10% and 20% above RPS to claim reduced emissions relative to the IOU. However, these scenarios appear not to include the IOU's future contracts and self-generation in place for 2020 that exceed the 33% RPS mandate. These contracts place IOU 2020 RPS eligible generation at 43.0% for PG&E, 41.4% for SCE, and 45.2% for SDG&E. The actual IOU generation mix above the RPS requirement—as well as any other carbon-free resources such as nuclear and large hydro included in the resource mix of the IOUs and CCA—should be considered when assessing the incremental GHG emissions reductions a CCA can achieve relative to the IOU. This Study includes a forecast of the amount of RPS-compliant renewable energy resources PG&E and SCE own or procure based on both IOUs historical and known future RPS performance.

G.2. Additional Study Assumptions

Key Study assumptions are described in detail within each section of this Study (including forecasts based on the source data). This section highlights additional Study assumptions not covered elsewhere.

G.2.a Participation Rates

Assumed participation rates (the opposite of opt-out rates) inform CCA feasibility. Participation rates are influenced by many factors including the number of DA customers within a CCA service area, IOU rate competitiveness, and the attractiveness of product and program offerings. In many CCA feasibility studies participation and "opt-out" assumptions have differed greatly from actual observed participation rates, with real-world participation rates higher than assumed in the feasibility studies. Other feasibility studies reviewed by the authors excluded DA customers, consistent with the experience of operational CCAs as shown in Table 5. Participation rates also vary greatly by CCA and over time.

For the purposes of this Study, DA customers, who comprise a varying percentage of customer load depending on the participation scenario assessed, are assumed to opt out of the CCA. An additional conservative opt-out rate of 15% (85% participation rate) is assumed for all remaining customers for all participation scenarios. In total, 38.5% of the AWG Jurisdiction's load is excluded from the CCA procurement analysis because the customers are assumed to stay with the incumbent IOU or ESP.

Table 5 Participation Rates for California CCA Programs[50]

CCA Name	Feasibility Study Participation Assumption	Include DA Customers?	Actual Participation Rate
Default Established by CPUC[51]	95% of Residential 80% of Non-residential	No	N/A
San Jose Clean Energy[52]	85 % of Residential 75% of Non-Residential	No	N/A
Peninsula Clean Energy[53]	85%	No	99%[54]
Sonoma Clean Energy[55]	70-75%	No	92%[56]
Inland Clean Power[57]	75% Residential 65% Non-Residential	No	N/A
LA County Clean Energy[58]	75% Residential 65% Non-Residential	No	N/A
MCE Clean Energy[59]	N/A	No	77% in 2010 86% in 2016[60]
Central Coast Power (This Study)	85%	No	N/A

Reducing the participation rate (or raising the opt-out rate above what has been experienced) does not necessarily harm feasibility results. Although lower participation results in lower revenue projections, costs should be similarly reduced. The actual risk from changes in opt-out (or opt-in) arises from the CCA's exposure to power markets. Should the number of participating customers deviate significantly from projections, the resultant under- or over-procurement of electricity would be transacted though CAISO, increasing CCA exposure to losses or premiums. Although this Study analyzes detailed customer load profiles—how and when customers use energy—it does not model the procurement risks associated with extreme customer fluctuations. Rather, the pro forma analysis includes funding of a contingency reserve and level of working capital meant to allow the CCA to handle this power market exposure. However, customer attrition is a real risk faced by all CCAs. In particular, CCA rates that fail to be competitive with IOU rates would likely result in customer flight. Modeling this risk would require a detailed production cost model and is beyond the scope of this Study. However, given that power costs are the largest expense of the CCA, it is reasonable to assume that significant changes in power prices would, to some extent, impact IOUs and CCAs alike, potentially mitigating this risk.

G.2.b Opt-up Rates for 100% Renewable Content

The Study assumes that 2% of customers, by total load, opt-up to the 100% renewable energy product that Central Coast Power could offer. This 2% opt-up assumption affects procurement, rates, economic impacts, and GHG emissions. While consistent with what other CCAs have observed for 100% renewable programs,[61] the 2% opt-up assumption could have a significant impact on CCA operations should the contracted amount of renewable generation differ greatly from actual customer enrollment.

G.2.c Use of Historical Data

Finally, the assumptions and methodologies briefly outlined here and substantiated throughout the report are based on historical data. However, projecting how each of these trends will manifest in the future, and even the potential impact of a CCA on the trends themselves, does not create certainty. As is commonly stated in investment prospectus literature, "past performance is not an indicator of future results."

II. Technical and Financial Analysis

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II. Technical and Financial Analysis

This section describes the methodology and primary assumptions used to conduct the technical feasibility analysis of the Central Coast Power CCA.

The first step taken in assessing CCA technical feasibility was evaluating the cost of electricity procurement under the eight different participation scenarios and three different renewable energy content scenarios. While historical electricity consumption for the Tri-County Region follows a somewhat predictable load profile, managing the CCA's exposure to volatile CAISO prices when serving the high and low extremes of customer demand can be the difference between a successful and unsuccessful power procurement strategy.

The fundamental measure for CCA feasibility is the achievement of the CCA goals and objectives while maintaining electric rates that are competitive with the incumbent utilities and remaining financially viable.

The power procurement cost forecast in this Study was developed utilizing a Monte Carlo simulation tool that performs a statistical analysis by considering the past performance and variance in the following variables:

- Customer Load
    - The load analysis uses historical usage data for any given hour of any given month to determine the historical hourly average load and standard deviation with confidence intervals to estimate the hourly load and quantity of power needed for the Study period.
    - This hourly load analysis is then adjusted for future years based on a load forecast.
    - Forecasted energy usage for every hour of every day for the 2020–2030 Study period is analyzed using a normal statistical distribution with differentiation between weekdays and weekends/holidays.
        - In a strategy to minimize CAISO market exposure, the Monte Carlo model uses PPAs to fulfill the lower bound 90% confidence level load estimate for each hour of each month with differentiation between weekdays and weekends.
        - The Monte Carlo simulation then calculates the difference between the forecasted load and simulated actual demand for every hour of the Study period to estimate the associated CAISO market exposure—which means either selling excess energy into the market or purchasing additional energy from the market as needed.
- Customer-Owned Distributed Generation
    - The customer-owned solar DG photovoltaic (PV) adoption and output increases during the 2020–2030 Study period as described in Section II.A.5.a.
    - Therefore, the electricity supplied by the CCA is reduced by the expected incremental DG solar PV.
    - The DG PV output is estimated for every hour of every day for the 2020–2030 Study period with a normal statistical distribution for variable output with differentiation

between weekdays and weekends/holidays.

- Bulk scale Generation Variability
  - The actual output from bulk renewable generation can vary randomly between -6% and +6% of the day-ahead expectation because of weather effects on generation. On average, renewable generation output meets day-ahead expectations. This is considered in the renewable Power Purchase Agreement (PPA) supply and adjustments to exposure to CAISO supply costs are made accordingly.
- CAISO Supply Costs
  - The simulated hourly CAISO pricing for the 2020–2030 Study period uses one-hour day-ahead and five-minute real-time CAISO locational marginal pricing from January 2013–October 2016, statistically analyzed with beta distribution.[62] The supply costs in the simulation are constrained by the maximum and minimum market prices encountered for any given hour of any given month, with differentiation between weekdays and weekends/holidays.
- Storage Costs
  - For the purposes of this Study, the Central Coast Power CCA was assumed to maintain energy storage capacity equivalent to 1% of the annual peak load in compliance with California Assembly Bill 2514.[63]

Once the variables were loaded, the Monte Carlo simulation was run 10 times to provide a range of expected outcomes including identification of an upper bound 95% confidence interval. Each run of the simulation corresponds to 672 hourly calculations for a 28-day month and 744 hourly simulation calculations for a 31-day month—for 4,018 hourly calculations for each year of the Study period, or 40,180 hourly simulation calculations for each variable after 10 runs of the Monte Carlo model. Within this context, an upper bound 95% confidence level translates to a 95% probability that the electricity demand and the price of power will be at or below the amount identified. The Monte Carlo simulation attempts to constrain the variables that comprise load forecasting and power purchasing based on historical data and future uncertainty, especially in light of the emerging market for customer-owned DER and bulk scale renewable generation and storage.

Once the forecast for future demand and power procurement costs were developed, these forecasts were incorporated into a cost of service analysis to determine the rate competitiveness and financial viability of the CCA over the Study period. The cost of service analysis relied on traditional utility ratemaking principles and followed an industry standard methodology for creation of a financial pro forma to forecast the future economic and financial performance of the CCA program. The first step in the cost of service analysis was developing the projected CCA program revenue requirement which is the amount of money to be collected from customers required to cover the costs of the CCA program. The revenue requirement, includes: all operating and non-operating expenses; debt-service payments; a contingency allotment; a working capital reserve; and a rate stabilization fund. The revenue requirement was based on a comprehensive accounting of all pertinent costs and projections of customer participation; assumptions and input development are described later in this report. Cost assumptions relied on historical publicly-available information, power cost forecasts conducted for this Study, data provided by PG&E and SCE, and subject matter expertise gained working with a host of public utilities and similar organizations over decades. After the revenue requirement was established, CCA generation rate proxies were developed for each rate class for both PG&E and SCE customers. Although a comprehensive rate design was not conducted, these rate proxies are designed to recover the attributable full cost to serve each customer class. Once the rate proxies were developed, an analysis of the forecasted annual revenues and operating expenses was conducted to determine the long-term financial viability of the CCA.

The remaining discussions within this report section describe in more detail the Study's components and are organized as illustrated in Table 6:

Table 6 Study Section Organization

Subsection Heading and Description	Relevant to All Audiences?	Relevant to Technical Audience?
Introduction	Yes	Yes
Approach – Details on the data, assumptions, forecasts and analysis	Maybe	Yes
Results – Estimates derived from the Approach	Yes	Yes

A. Load Study and Forecast

A.1. Load Study Introduction

To operate as a CCA, Central Coast Power must forecast its customer electricity demand and procure energy and energy-related services to meet that demand as it fluctuates throughout each hour of each day. Fundamentally, power procurement consists of forecasting and risk management tasks, with analysis based on historical demand data as well as weather forecasts, expectations for generation resource availability, and other forward-looking variables. Electricity demand and price forecasts are never exactly accurate, even an hour before, because actual energy use varies from historical patterns due to changes in weather, customer behavior, general economy, underlying energy costs, energy efficiency efforts, and other factors.

Because energy use can change from what was expected/forecasted minute by minute, hour by hour, day by day, and so on, energy suppliers attempt to build a resource supply portfolio with a diversity of power supply contracts of differing types, durations, and cost structures. Power purchase agreements can be made for suppliers to provide energy across various time frames (hourly production or all-the-time production), or to function at different usage levels (such as a few hours per year or exclusively in the springtime), or for different performance lengths (five years or 20 years). Significantly more information on this subject can be found in Section II.B of this report.

In support of this Study, and using the CCA-INFO tariff provision enabling municipalities to request constituents' energy usage data in assessing the feasibility of a CCA, data requests were submitted to both PG&E and SCE to obtain two years (2014–2015) of electricity demand and usage data for residents and businesses within the Tri-County Region. [64] The data from SCE and PG&E varied in granularity. SCE provided monthly load data by jurisdiction and also supplied load profiles corresponding to the date range of the CCA-INFO data.[65] Load profiles are used to estimate the hourly usage by customers in different rate classes based on the total monthly usage by customers within each rate class. PG&E provided the actual 15-minute usage for each commercial account in the requested area, as well as the 60-minute usage figures for residential customers. This more granular level of detail provided by PG&E resulted in more precise load profiles on the exact accounts within Central Coast Power's territory when compared to the averaging that occurs with load profiles.

An electric rate tariff defines the relationship between a utility and its customers and typically provides all rules, terms of service, and rate information applicable to a particular customer class. Within the U.S., each electric utility has separate and distinct tariffs by customer class, e.g., residential, commercial, and industrial customer classes. Certain utilities may also have agricultural, governmental, institutional, and region- or location-specific rate classes.

The rate class categories for this Study are summarized in Table 7 and combine the various rate tariffs for customers in both IOU territories into larger categories to allow for easy comparison and effective rate class definition for the CCA program. PG&E's detailed customer data specified nearly 120 tariffs, while SCE's CCA-INFO data provided roughly 12 tariffs. Those tariff classifications were then mapped onto the categories listed in Table 7.

Table 7 Customer Categories

Customer Category	Example Customers within Class
Residential	Customer occupying single-family or multi-family residential dwellings
Residential CARE	California Alternate Rates for Energy (CARE)-eligible program participants, including low-income individuals and families and those receiving public assistance
Very Large Commercial > 1,000 kW	Large manufacturing facilities, oil and gas processing, colleges and universities, correctional institutions
Large Commercial 500 < 1,000 kW	Large retail centers, supermarkets, hotels, hospitals, wineries, sewage treatment
Medium Commercial 200 < 500 kW	Mid-sized retail stores, restaurants, schools
Small Commercial < 200 kW	Small-sized retail and convenience stores, doctor offices
Agriculture	Agricultural water pumping and product processing
Street Lighting	Customers with either government-owned or privately-held street and outdoor area lighting
Traffic Control	Government-owned traffic control equipment

Using the data provided by the IOUs, the total load within the Tri-County Region was analyzed to determine the energy use profile for a 24-hour period for each month, with differentiation between weekdays and weekends/holidays.

A.2. Average Comparison of Whole Territory and Bundled-Only Customer Usage

Currently, customers in the Tri-County Region, with the exception of those in Lompoc which have a municipal utility, receive electricity supply from either an IOU or a DA ESP.[66] DA customers have an existing contract with a third party ESP and therefore are unlikely to join the CCA. The difference between the total usage for the AWG Jurisdictions and the bundled only (non-DA) usage is approximately 23.5% based on annual consumption data for 2014 and 2015. This means that approximately 23.5% of the AWG

Jurisdictions' load is currently being served by DA ESPs rather than the IOU. Only 14.2% of the entire Tri-County Region is served by DA ESPs, meaning that a greater proportion of load in the Advisory Working Group jurisdictions is served by DA than in the Tri-County Region. Table 8 presents the energy usage served within the AWG Jurisdictions territory, depicting the load attributable to bundled and DA customers.

Table 8 Comparison of AWG Participation Scenario Territory Historical Total Customer Usage and Bundled-Only Customer Usage, 2014-15

Annual AWG Territory (GWh)	Annual AWG Bundled (GWh)	Annual AWG Direct Access (GWh)	Direct Access % of Total
5,454	4,172	1,282	23.5%

For the purposes of this Study, the assumption is that DA customers will opt out of the CCA and continue purchasing electricity from the ESP. Therefore, only the bundled customer usage is provided in the load data throughout the remainder of this report. The same assumption is made in most other CCA feasibility studies, including the Silicon Valley Clean Energy Business Plan and the Los Angeles County Clean Energy Study.[67]

A.3. Tri-County Electricity Consumption Overview

The bundled customers in the Tri-County Region use approximately 8,493 gigawatt-hours (GWh) per year. In comparison with other CCAs currently in operation, this is over four times as much electricity as Sonoma Clean Power (1,550 GWh), almost four times as much as MCE (1,687 GWh), and over eight times as much as LCE (770 GWh). For added perspective, the Tri-County Region consumes more electricity than the entire state of Vermont, which consumed 5,521 GWh in 2015.[68]

Another way to look at electrical consumption is to compare the annual GWh sold within each of the IOU territories and the percentage of sales in the Tri-County Region attributable to each IOU. As detailed in Table 9, the Tri-County Region accounts for 3.7% of PG&E bundled electricity sales and 6.4% of SCE bundled electricity sales.

Table 9 Potential Central Coast Power CCA Electricity Sales Relative to Incumbent Investor Owned Utilities

	2014 Non-DA Energy Sales[69]	2015 Central Coast Power	Rough Estimate for CCA potential Percentage of IOU Sales
PG&E	74,547 GWh	2,766 GWh	3.7%
SCE	88,986 GWh	5,727 GWh	6.4%

As shown in Figure 7, Ventura County is the largest electricity consumer of the three counties considered in this Study, followed by Santa Barbara and then San Luis Obispo Counties. Collectively, customers in the incorporated cities in San Luis Obispo and Ventura Counties consume more electricity than customers in the unincorporated county. The reverse is true in Santa Barbara County.

Figure 7 Annual Demand in GWh by County

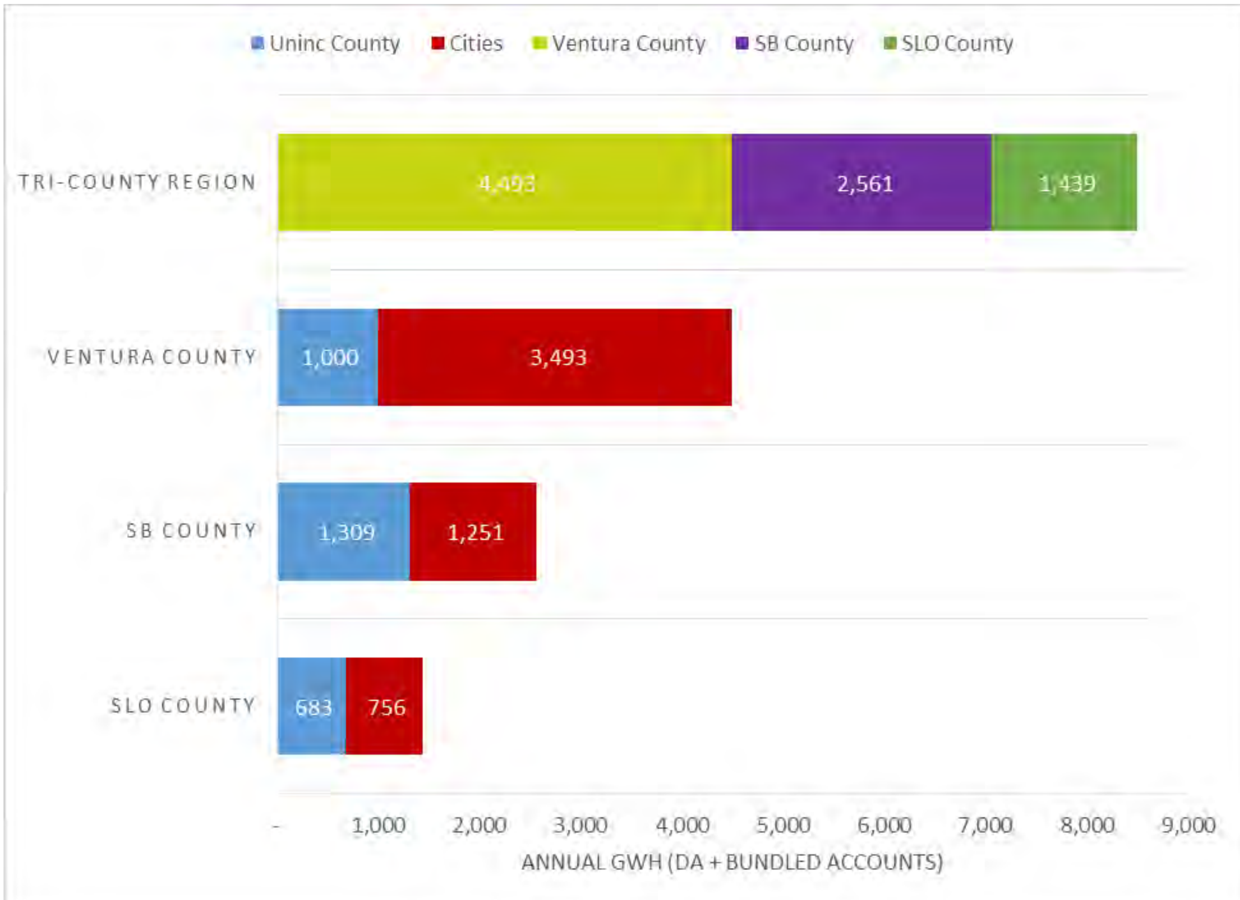


Figure 8 and Figure 9 show the annual electricity consumption and number of accounts, respectively, for each of the eight geographic participation scenarios. The consumption and number of accounts generally mirror each other, with the exception of unincorporated San Luis Obispo and Santa Barbara Counties.

Figure 8 Annual Demand in GWh for Each Participation Scenario

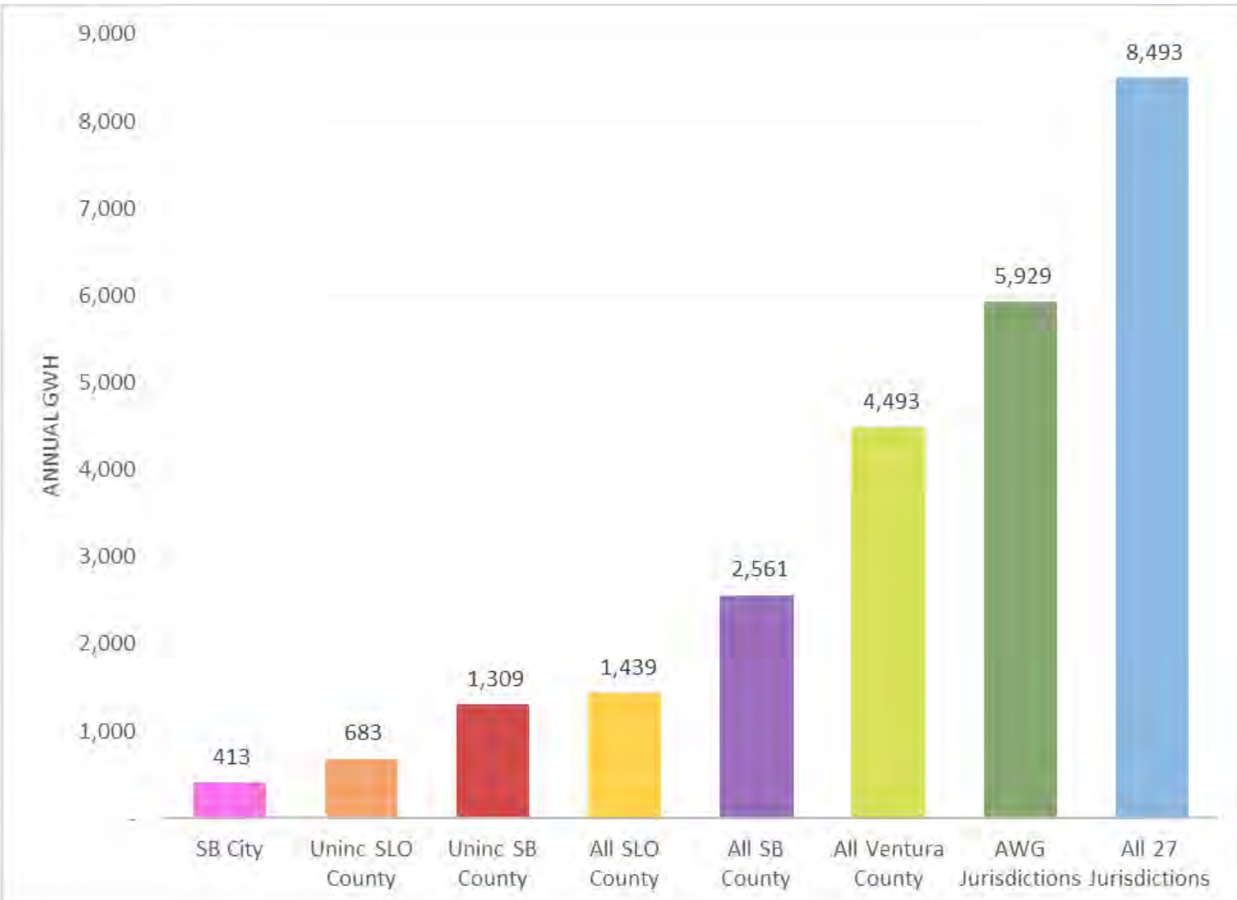
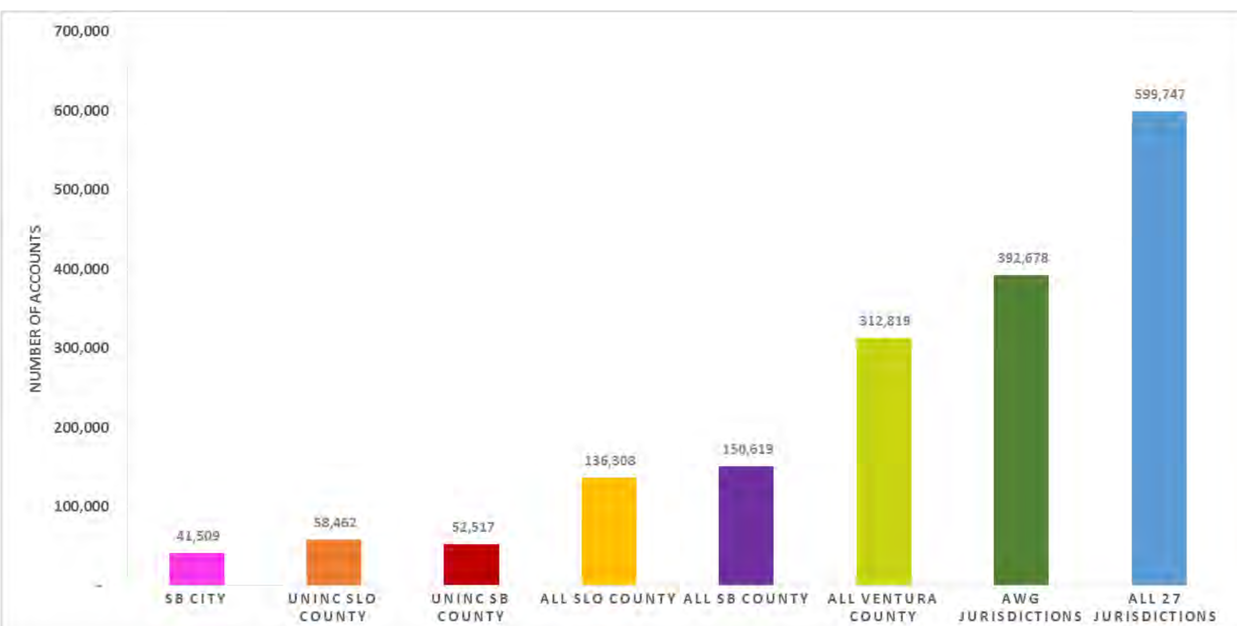


Figure 9 Number of Accounts in Each Participation Scenario



A.4. Load Study Approach

This section contains an analysis of the CCA-INFO data provided by the IOUs. The AWG Jurisdictions scenario is displayed within the body of the report with additional detail in Appendix D, the alternate participation scenarios are included in Appendix C and Appendix E through Appendix J. Also, the figures presented here are for electric service customers within the territory excluding DA customers, who comprise 23.5% of electricity usage in the AWG Jurisdictions.

The figures in this section illustrate various elements of the load study. In these figures, the month and hour of day appear on the horizontal axis, while the average hourly electricity demand (measured in kilowatts [kW] or megawatts [MW]) for each month appears on the vertical axis. Therefore, the area under the demand (kW or MW) curve for a specific hour represents the average kilowatt-hour (kWh) or megawatt-hour (MWh) energy usage during that hour. Demand (kW) is denoted in the same unit of measure as the source data. For example, the CCA-INFO–based data analysis will use power in kilowatts (kW) and energy in kilowatt-hours (kWh). (Note that 1,000 kW is equal to 1MW and 1,000 MW is equal to 1GW.)

Figure 10 and Figure 11 show the minimum, average, and maximum electric consumption for a 24-hour period in each month by weekdays and weekend/holidays, respectively. These data indicate that significant demand variability exists from May through October, with less variability during winter and early spring. This variability is due in part to higher temperatures in the summer months, increasing air conditioning load, and also different consumer behavior, such as agricultural processes in the summer months. Figure 10 illustrates that the peak demand for the year occurs on a weekday in October approaches 1.2 million kW (or 1.2 GW).

kW and kWh Explained

*There are two primary electricity commodities: **energy**, measured in **kWh**, and **demand**, measured in **kW**. In typical parlance, energy represents a flow, or volume, of power over some period, typically expressed in terms of hours. For example, a customer using an average of 1 kW over the course of a month uses 730 kWh (1 kW times 730 average monthly hours). A 100 MW power plant running at full production for a day produces 2,400 MWh of energy (100 MW times 24 hours). Capacity refers to the capability of available resources to meet the system's requirement for power. In the power plant example, 100 MW is the capacity of the plant. Capacity and demand represent the amount of power available, or required to be served, at a particular instant.*

Figure 10 AWG Jurisdictions Participation Scenarios Minimum, Average and Maximum Weekday Electricity Load (Non-DA, Bundled Only)

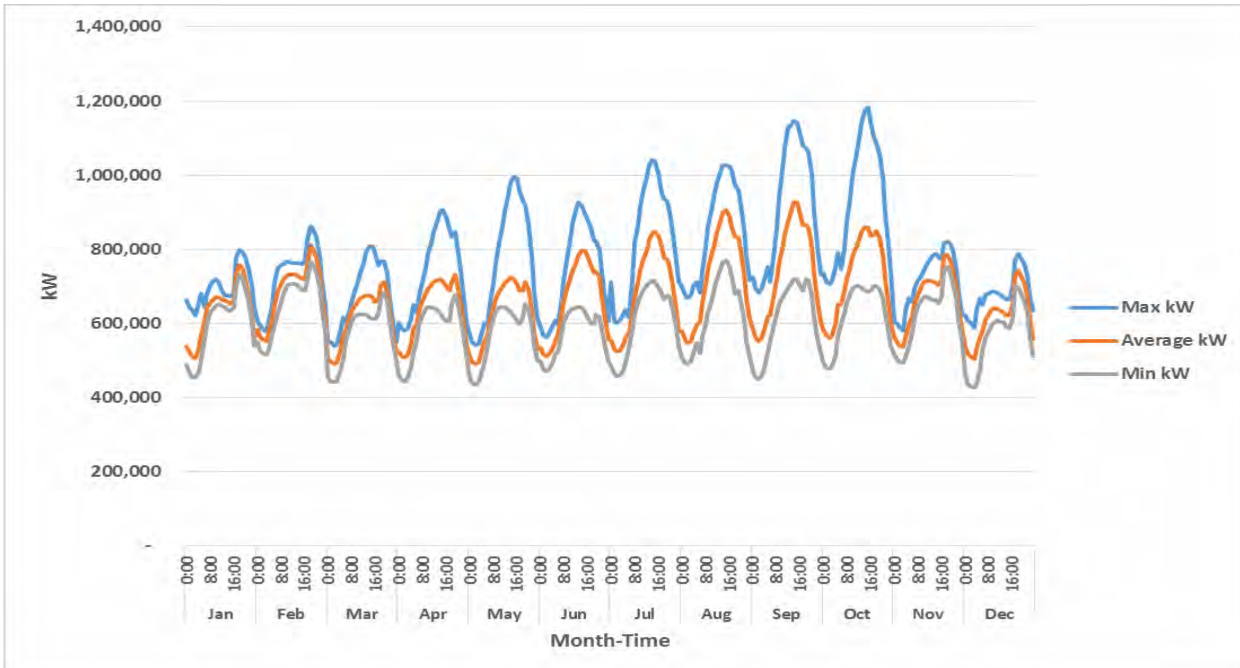


Figure 11 AWG Jurisdictions Participation Scenarios Minimum, Average and Maximum Weekend/Holiday Electricity Load (Non-DA, Bundled only)

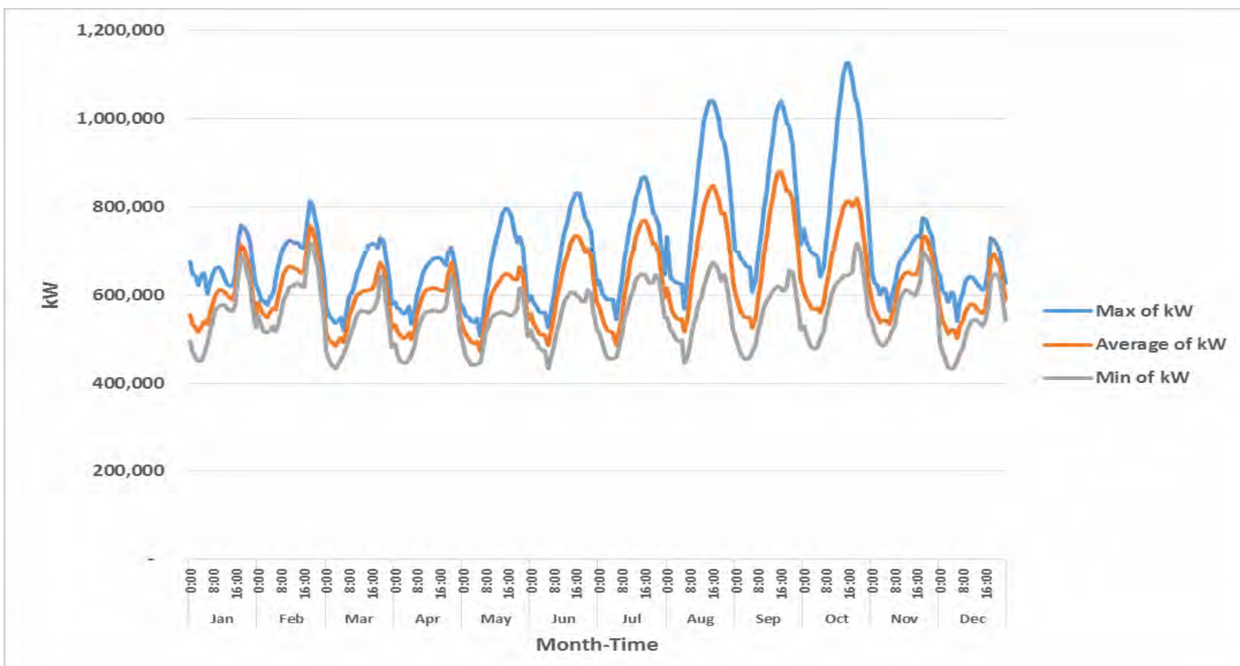


Figure 12 and Figure 13 present the average customer usage for each hour of each month, broken down by customer rate classification. Within these figures the proportion of load for each customer classification shifts throughout the day. The average peak is higher in the summer months of July to September, and the timing of the peak also shifts by season. January and February see a relative plateau in the early afternoon hours before a ramp up in the late afternoon. Meanwhile, the summer months experience significantly less of a plateau and peaks occur in the midafternoon, likely due to air conditioning load and agricultural process timing.

Multiple factors influence a change in load profile shapes from what LSEs have traditionally seen, and make the load profiles more dynamic. These factors include:

- **Customer-owned solar PV** that has the effect of lowering customer electricity demand by serving customer load behind the meter. Customer-owned PV also results in increased variability in the load serviced by the LSE as clouds and other factors influence the output of the solar panels. The effects of customer-owned solar are discussed in more detail in Section II.A.5.a.
- **Electric vehicles** that can draw as much electricity as the rest of the home. SCE and PG&E are developing specific rate structures for electric vehicles to incentivize charging at certain times of day or in some cases even allow the IOU to interrupt or reduce charging when system conditions dictate.

Figure 12 AWG Jurisdictions Participation Scenario Non-DA Weekday Average Electricity Demand (kW) and Usage (kWh) for Each Hour of Each Month

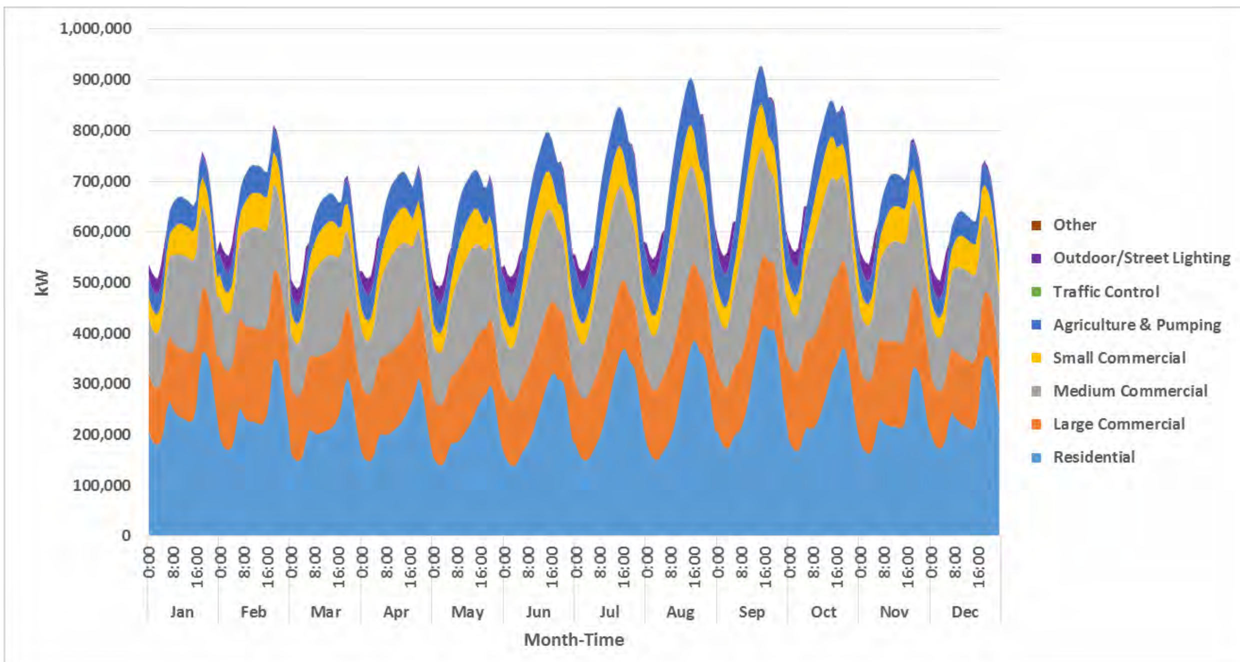
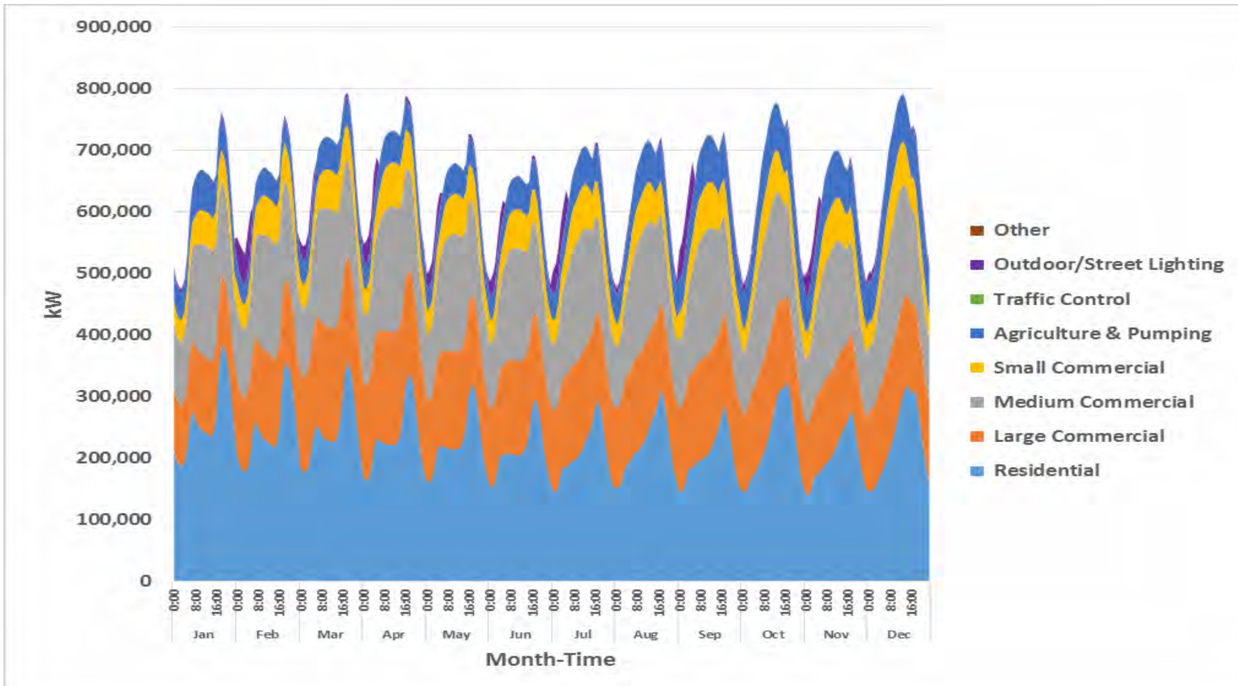


Figure 13 AWG Participation Scenario Non-DA Weekend/Holiday Average Electricity Demand (kW) and Usage (kWh) for Each Hour of Each Month



A.5. Load Study Results

To predict customer load in the Central Coast Power territory through 2030, multiple sources were blended to produce a reasonable forecast. First, the growth profile for each IOU was developed. Then the weighted average growth rate by participation scenario was calculated using relative load proportions for PG&E and SCE. The average load proportion by IOU for the eight participation scenarios appear in Table 10.

Table 10 Breakdown of Participation Scenario Load by IOU Territory

Participation Scenario	Percentage of Load in SCE Territory	Percentage of Load in PG&E Territory
All 27 Jurisdictions	63%	37%
AWG Jurisdictions	71%	29%
Unincorporated Santa Barbara County	30%	70%
All Santa Barbara County	44%	56%
Unincorporated San Luis Obispo County	-	100%
All San Luis Obispo County	-	100%
All Ventura County	100%	-
City of Santa Barbara	100%	-

The two years' worth of electricity CCA-INFO usage data is not a large enough sample set to develop an adequate load forecast. Therefore, historical utility level consumption data for 2001-2016 was pulled from U.S. Department of Energy's Energy Information Administration (EIA) Form 861 for both PG&E and SCE.[70] This data was analyzed and a logarithmic line of best fit was created and extended through 2030. This data was then compared with the California Energy Commission's long-term procurement plan load forecasts, which are available through 2025 for the respective planning areas.[71] Because the two sources showed very different results by 2030, the average between the long-term procurement plan load forecast and the EIA consumption data logarithmic forecast was used for the load forecast for Central Coast Power, as illustrated in Figure 14 and Figure 15.

Figure 14 PG&E Load (Usage) Forecast through 2030

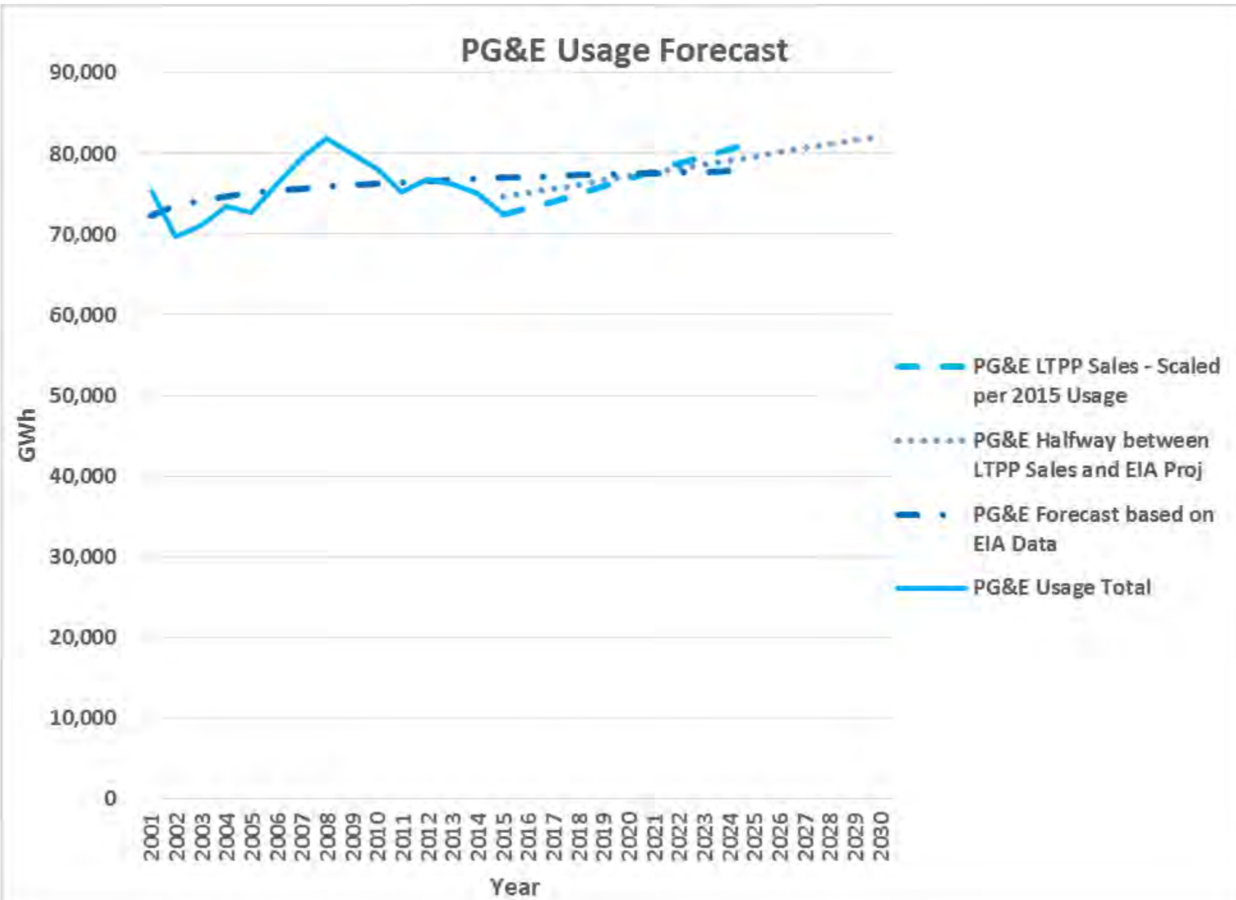
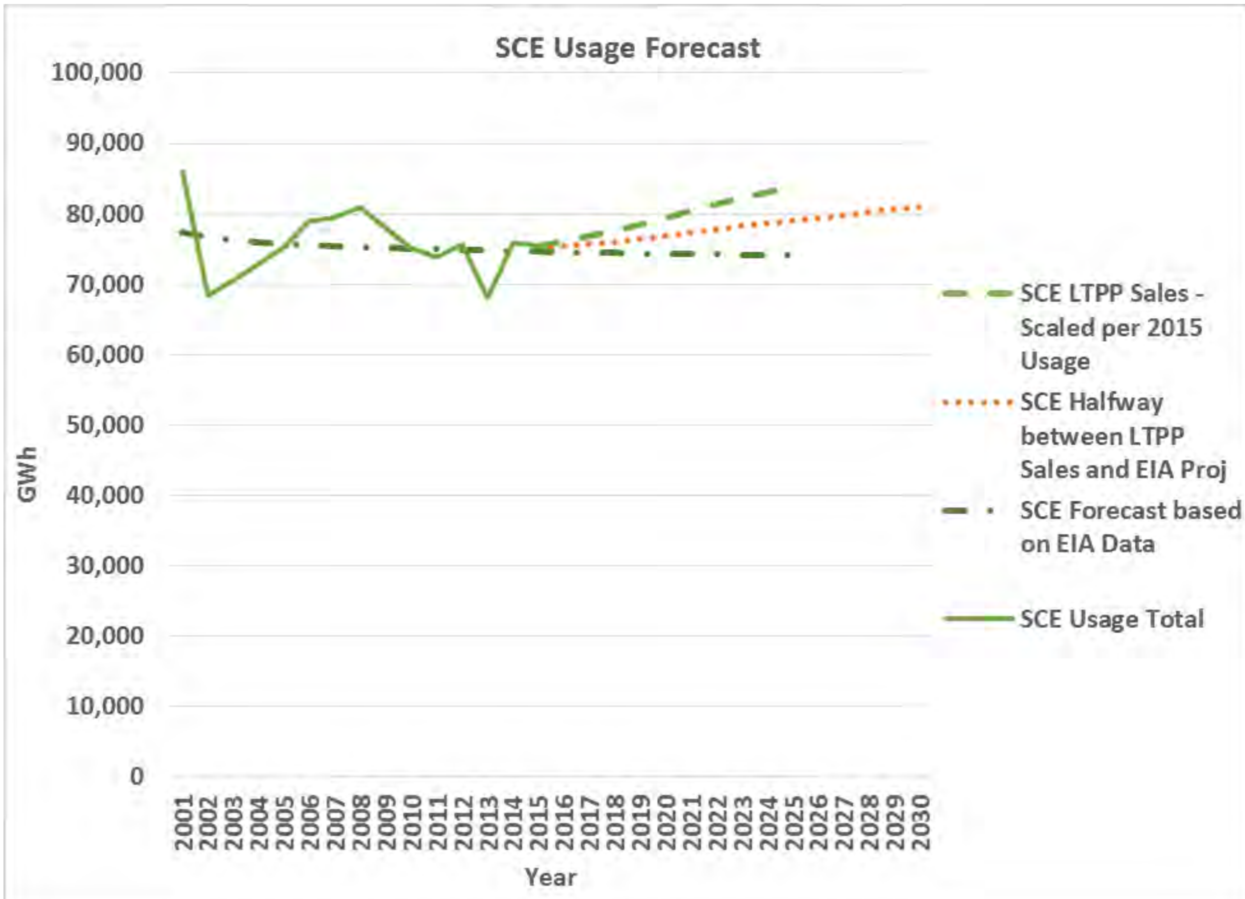


Figure 15 SCE Load (Usage) Forecast through 2030



A.5.a Customer-Owned Distributed Energy Resources

DER are power sources used "behind the meter" to provide all or a portion of the customer's electric load[72] and are frequently located on the customer's end-use site. DER tend to be smaller than typical utility-scale generation sources, but often feed energy back into the electrical grid, thus reducing the amount of generation needed from the LSE. An assessment of customer-owned DER is necessary to understand the future energy needs of CCA customers. Customer-owned DER (predominately DG PV) effectively reduce the amount of load that is served by the LSE. A more thorough discussion of the effect of DER on future CCA operations follows current and projected DER production within the Tri-County Region. The DER trends affect any Tri-County Region LSE--IOU, ESP, or CCA.

Data from the California Distributed Generation Statistics data set for the Tri-County Region demonstrate nearly exponential growth in customer-owned solar PV since 1993, as illustrated in Figure 16 through Figure 18.[73] This data was accessed in March 2017; the data set is continuously updated.

Figure 16 Customer-Owned Solar Photovoltaic in the County of Santa Barbara

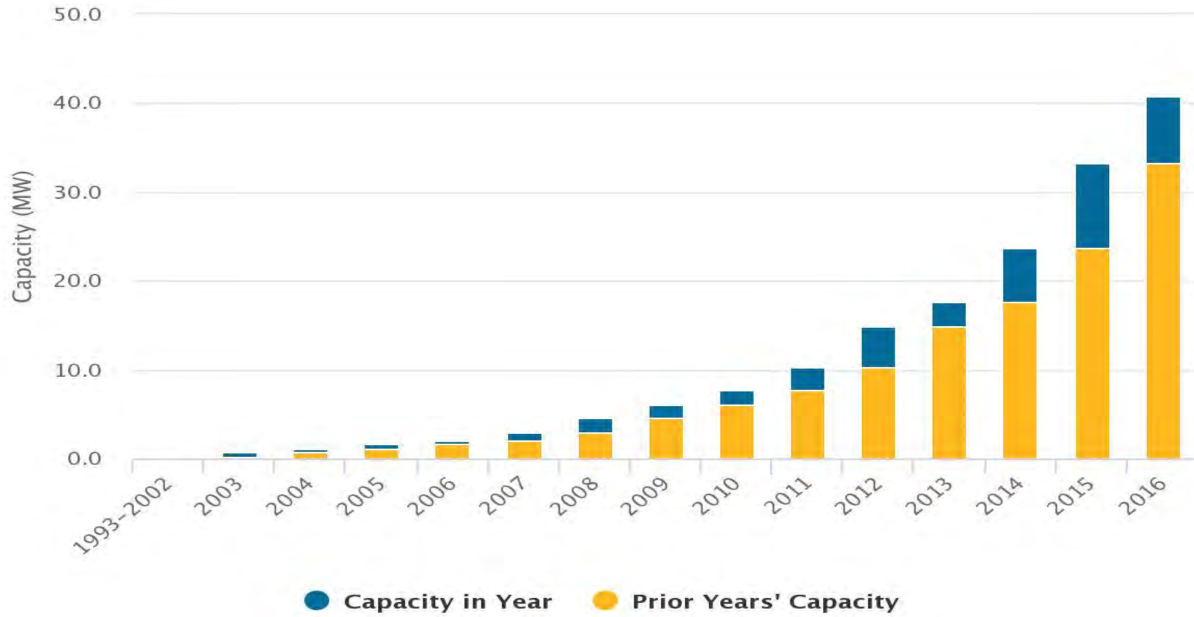


Figure 17 Customer-Owned Solar Photovoltaic in the County of San Luis Obispo

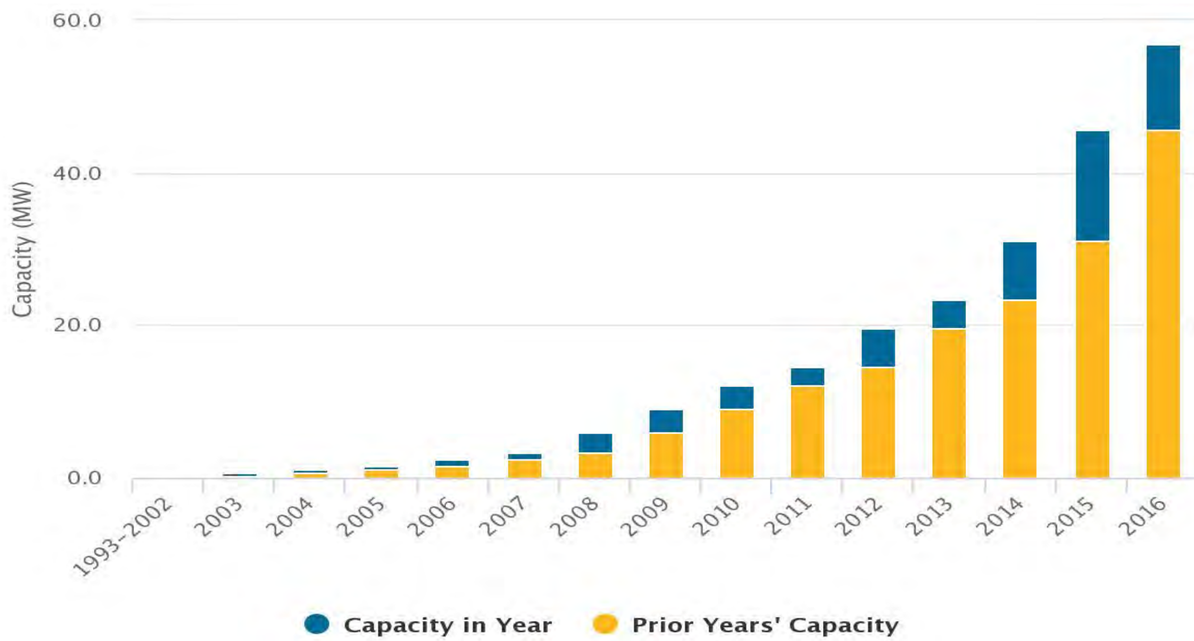


Figure 18 Customer-Owned Solar Photovoltaic in the County of Ventura

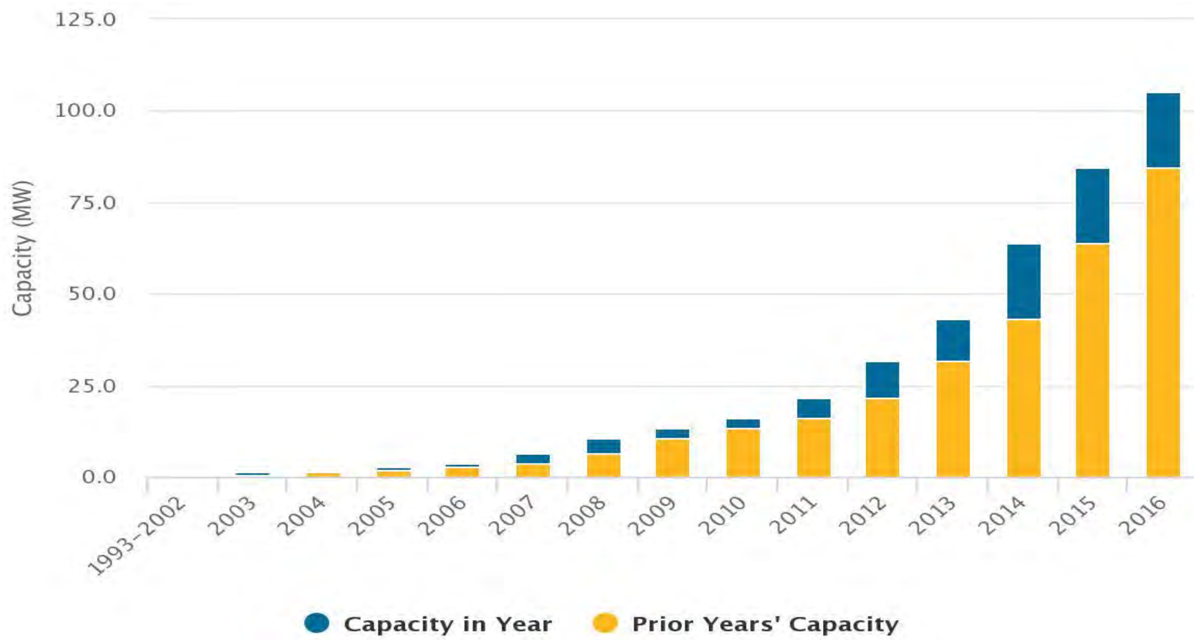
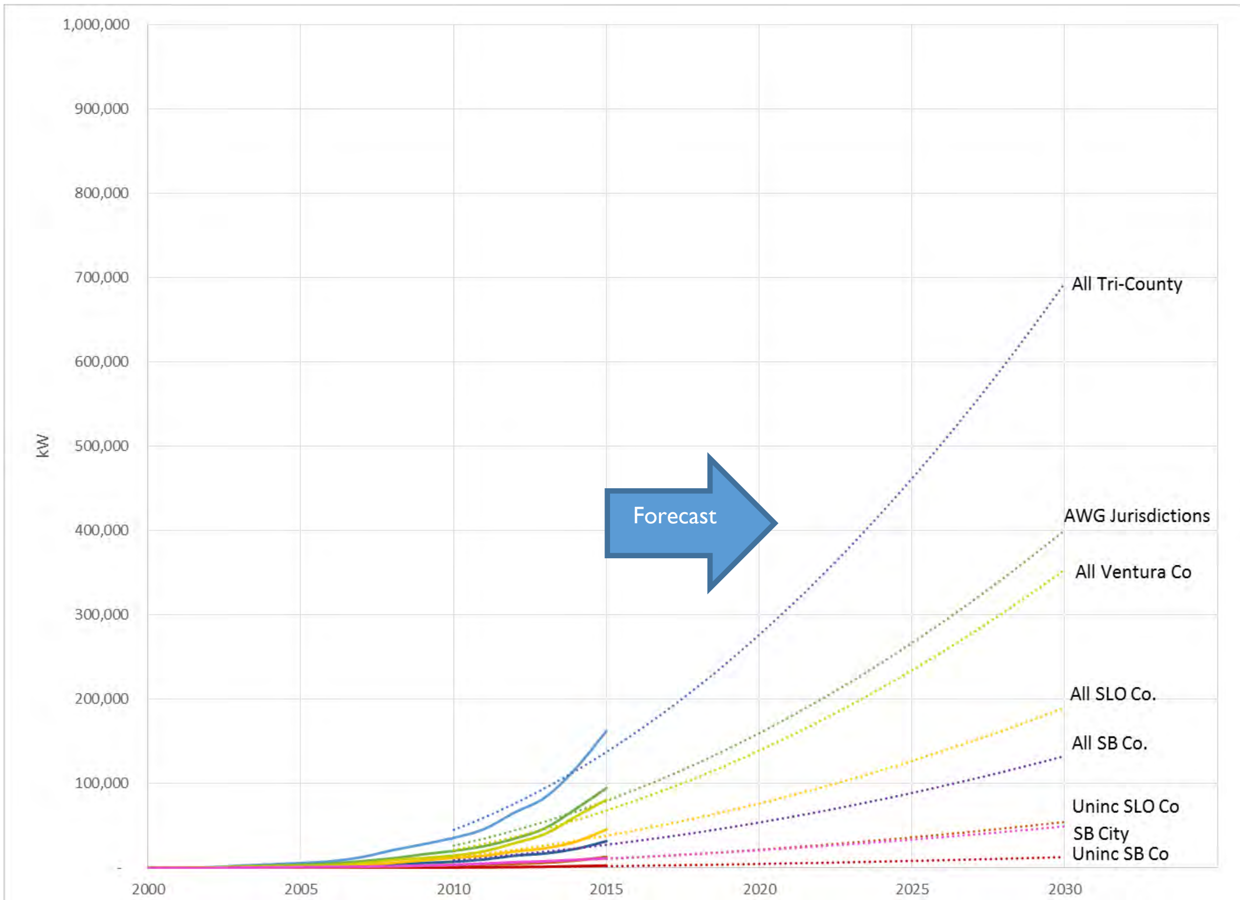


Figure 19 uses this California Distributed Generation Statistics data to build customized projections for each participation scenario based on historical (1993–2015) usage.[74] These projections assume that the customer DG adoption trends in Figure 16, Figure 17 and Figure 18 continue. However, the electrical distribution grid constraints discussed in Appendix B associated with high concentrations of DER might slow growth in the future. Moreover, policy changes in incentive and compensation models for encouraging DER could have a significant effect on proliferation.[75] Currently DG PV growth continues with the U.S. solar market nearly doubling in 2016.[76]

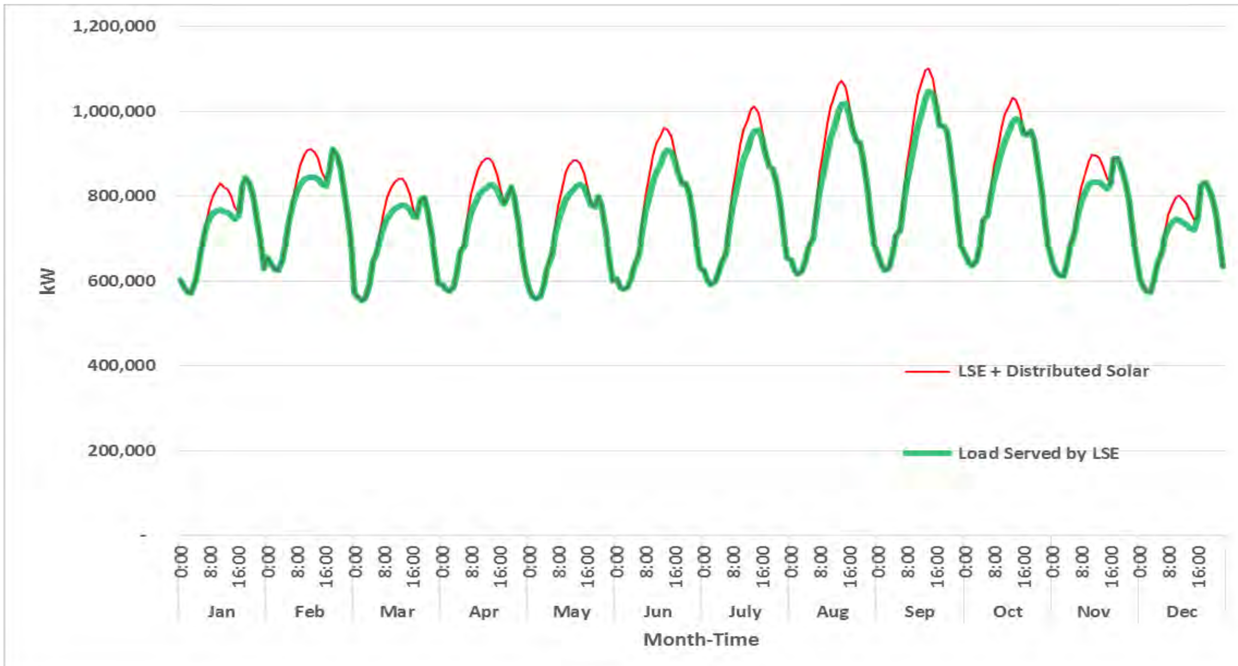
Figure 19 shows that Unincorporated Santa Barbara County has the least amount of installed DER capacity, despite nearly triple the annual usage as the City of Santa Barbara, and nearly double that of Unincorporated San Luis Obispo County. The reason for the lack of customer-owned DER penetration in Unincorporated Santa Barbara County is unclear.

Figure 19 California Solar Initiative Incentivized Customer-Owned Solar Photovoltaic in the Region with 2030 Forecast



In addition to the raw annual output projections displayed in Figure 19, customer-sited solar PV has a strong influence on hourly load profiles. Solar power is only available during the day, during which many customer-owned systems overproduce (relative to consumption) and does not produce while the sun goes down during times of peak residential demand. To include the potential effect of customer-owned PV, an hourly generation profile using the National Renewable Energy Laboratory's (NREL's) PVWatts calculator was created.[77] Figure 20 illustrates the customer-owned PV-served load over and above the electric load currently served by LSEs in the region for weekdays. In other words, the red curve on top of the green curve represents the level of electricity demand that would exist without customer DG PV.

Figure 20 Average Weekday Electricity Demand Plus Additional Load Served by Customer-Owned Solar for 2015, AWG Jurisdictions Participation Scenarios[78]



The growth in DER affects the load growth projected in Section II.A.5 (Figure 14 and Figure 15). The Study assumes that growth of customer-owned DER will offset forecasted load growth, resulting in less net electric load served by a CCA. Based on this analysis, as more and more customer-owned DER come online, the load served by the LSE (represented in Figure 20 by the green line) gradually decreases with 1.5% fewer kWh sold in 2030 than 2020. In addition to the overall annual load decrease, the LSE will be faced with a significant increase in the afternoon electricity demand as the sun sets and must provide electricity to compensate for this loss. The steep slope in 2030 from minimum production around noon through the maximum production in the evening must be accommodated by non-solar resources, demand reduction, and energy storage. Additionally, natural gas generators would likely keep running to rapidly increase or decrease output to balance electricity supply and demand given increasing magnitude of renewable resource variability. An analogy for this is an automobile going from stoplight to stoplight, accelerating as fast as possible after the light turns green, which reduces efficiency considerably. For the 2020 to 2030 period, Figure 21 illustrates the customer-owned PV-served load over and above the electric load currently served by LSEs in the region for weekdays. Table 11 shows the annual energy consumption, and customer-owned DG production resulting in the net load served by the LSE for the 2015 to 2030 period.

The Study assumes that growth of customer-owned DER will offset the increased demand for electricity that is expected over the Study period, resulting in declining energy sales for the CCA.

Figure 21 Average Weekday Electricity Demand Plus Additional Load Served by Customer-Owned Solar 2020–2030, AWG Jurisdictions Participation Scenarios

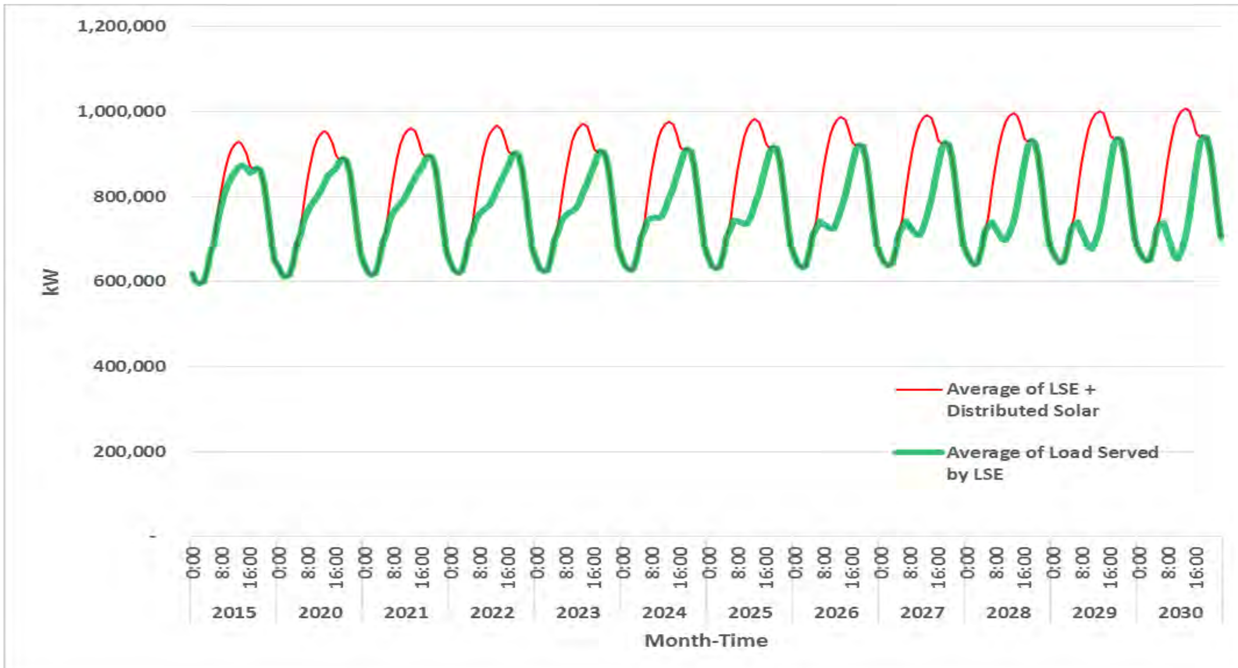


Table 11 Load, Distributed Generation, and Net Load Forecast, AWG Jurisdictions Participation Scenarios

Year	Annual Energy Consumption (MWh)	Annual DG Generation (MWh)	Annual Net Load Served by LSE (MWh)
2020	6,698,164	164,987	6,533,177
2021	6,735,965	202,979	6,532,985
2022	6,777,276	244,414	6,532,862
2023	6,811,982	287,988	6,523,995
2024	6,868,761	335,074	6,533,686
2025	6,888,329	381,954	6,506,375
2026	6,930,669	431,948	6,498,721
2027	6,971,608	483,660	6,487,948
2028	7,026,296	538,288	6,488,008
2029	7,047,280	592,489	6,454,791
2030	7,085,173	650,280	6,434,893

Figure 22 illustrates the customer-owned PV-served load over and above the electric load currently served by LSEs in the region for weekdays for year 2020; Figure 23 presents this data for year 2030.

Figure 22 Average Weekday Electricity Demand Plus Additional Load Served by Customer-Owned Solar for 2020, AWG Jurisdictions Participation Scenarios

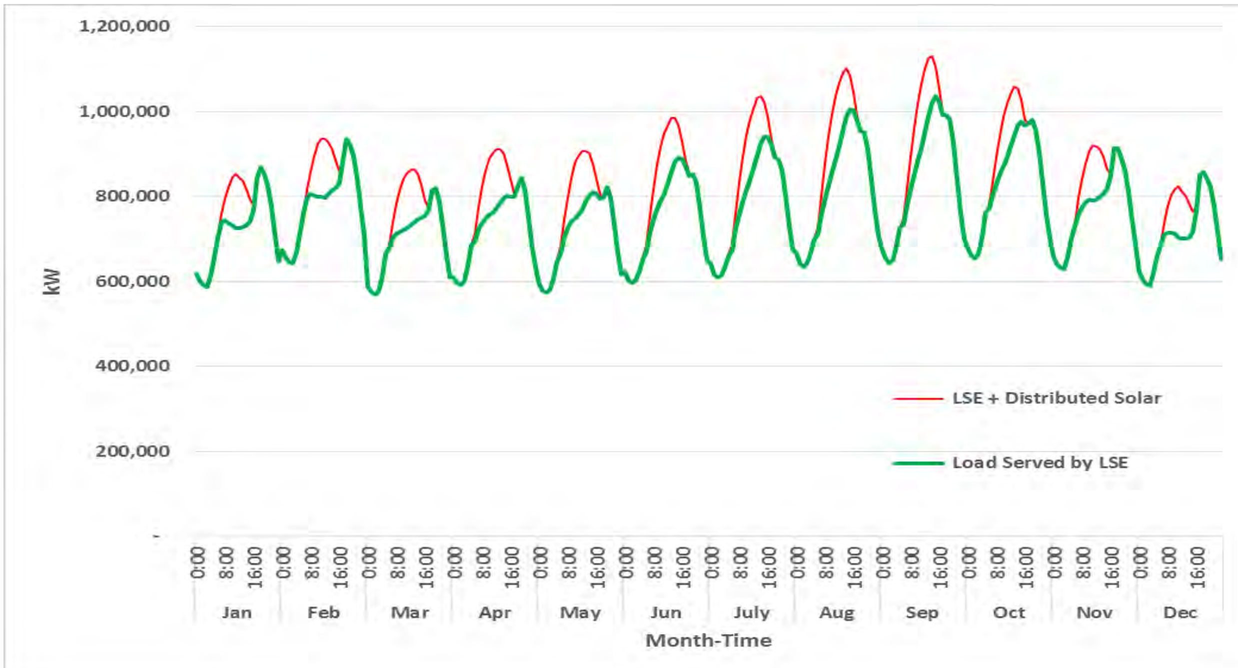
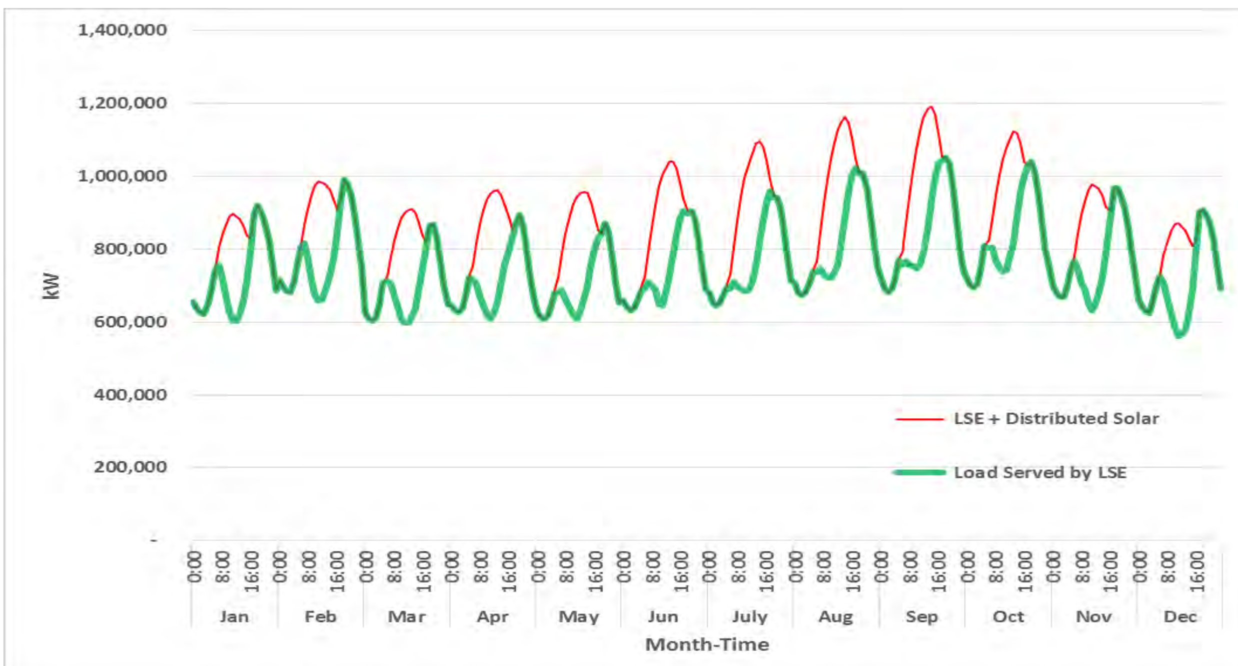


Figure 23 Average Weekday Electricity Demand Plus Additional Load Served by Customer-Owned Solar for 2030, AWG Jurisdictions Participation Scenarios



A.5.b Statistical Analysis

Energy usage is a function of many factors. The historical load data provided a basis for forecasting future consumption. To develop a forecast of usage, a simulation model was used to statistically analyze the historical range of electricity usage data as well as power supply costs. Using the baseline data, the Monte

Carlo model determined the statistical range of possible outcomes and confidence intervals for the expected range of electricity demand and power supply costs for each hour of each month over the eleven-year Study period.

Managing power purchases to serve varying customer demand for electricity at any given hour of any given month is the primary responsibility of a CCA.

Managing power purchases to serve varying customer demand for electricity is the primary responsibility of a CCA. The Monte Carlo simulation runs inform these decisions by projecting the likely load based on statistical probability of occurrence. For purposes of this Study, the Monte Carlo runs simulate the potential variability in future customer load based on past behavior. The task of forecasting customer load has become more complex with greater volatility introduced by increasing customer adoption of solar PV, which has the effect of reducing customer demand. Additionally, solar PV output is not constant, and a historically predictable usage pattern by a customer can increase and decrease over very short periods of time due to the variability of sunlight and the resulting increase and decrease in demand serviced by the LSE. The variability of both customer-owned variable generation as well as bulk scale renewable generation on the power supply side has also been modeled in the simulation by estimating exposure to CAISO energy markets by either selling excess energy or procuring energy to meet actual customer electricity demand.[79]

The CCA-Info data set was analyzed to calculate the average demand, standard deviation, and confidence intervals. This specified range (low end to high end) is the confidence interval which is expressed in percentages. Put another way, with a 95% confidence interval, there is a 95% statistical probability that the average price within a given hour is between the low and high end of the range based on historical sample data.

Figure 24 illustrates the range of weekday non-DA electricity usage for any hour of any month with 95% confidence intervals, and Figure 25 illustrates the same for weekends and holidays. Figure 24 and Figure 25 illustrate that the 95% upper bound confidence level is only slightly higher than the average demand curve. Essentially, 95% of the time, the electricity demand is fairly close to the average. However, the maximum and minimum demand curves can vary significantly from the average and 95% confidence interval range. These outlier deviations from the average represent procurement risk with excess energy likely being sold to CAISO at a loss and additional energy likely being procured from CAISO at a premium.

Figure 24 Weekday Electricity Usage Monte Carlo Confidence Intervals

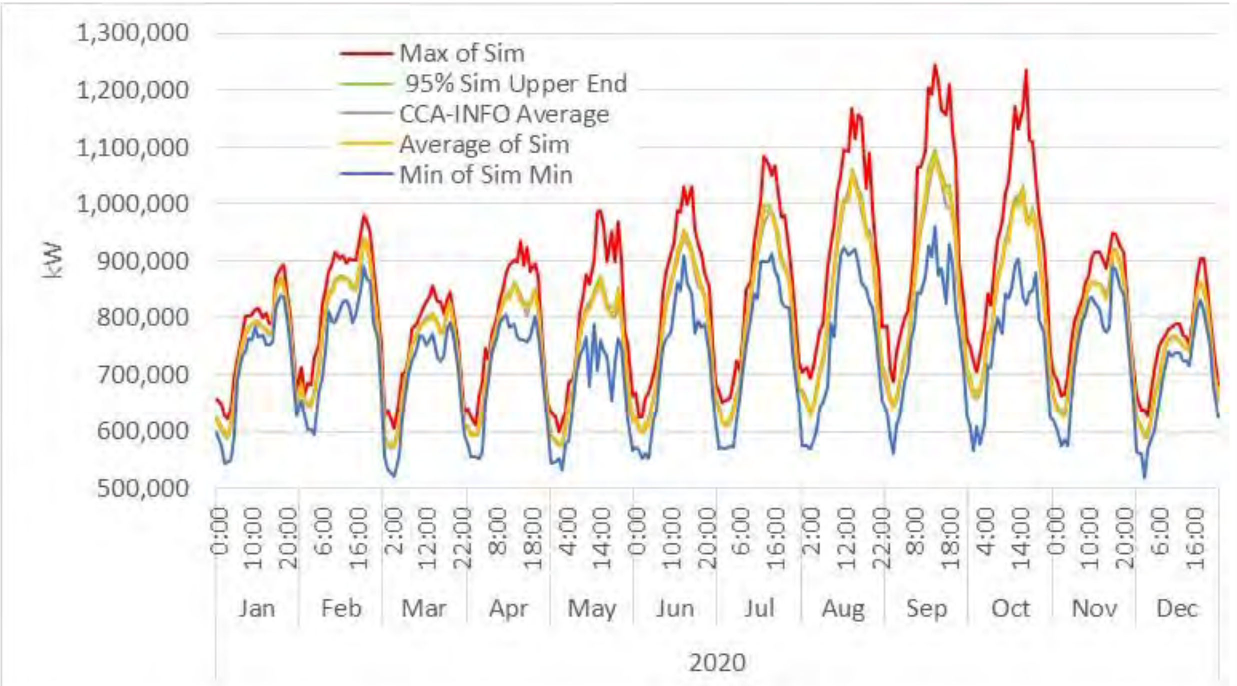
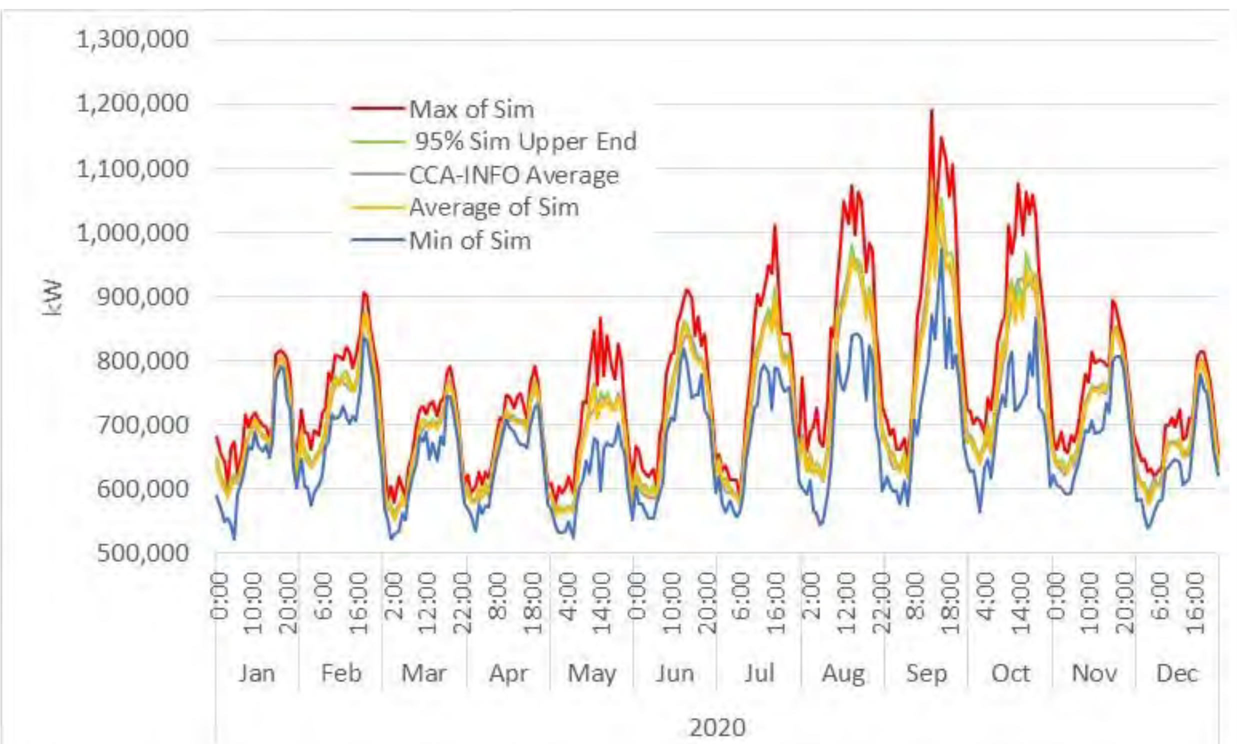


Figure 25 Weekend/Holiday Electricity Usage Monte Carlo Confidence Intervals



In addition to the hourly breakdown illustrated in Figure 24 and Figure 25, Table 12 shows the annual minimum, average, upper bound of the 95% confidence interval, and maximum simulated usage.

Table 12 Range of Annual Gross Electricity Usage Monte Carlo Simulation Outputs, AWG Jurisdictions Scenario

Year	Minimum (MWH)	Average (MWh)	95% Sim Upper Bound (MWh)	Maximum (MWh)
2020	6,680,929	6,697,947	6,698,164	6,712,597
2021	6,719,785	6,735,965	6,735,965	6,752,516
2022	6,761,333	6,777,276	6,777,276	6,791,616
2023	6,797,085	6,811,982	6,811,982	6,829,834
2024	6,853,589	6,868,761	6,868,761	6,881,848
2025	6,873,129	6,888,329	6,888,329	6,903,412
2026	6,917,589	6,930,669	6,930,669	6,945,113
2027	6,956,602	6,971,608	6,971,608	6,984,488
2028	7,011,318	7,026,296	7,026,296	7,043,277
2029	7,031,184	7,047,280	7,047,280	7,061,826
2030	7,068,492	7,085,173	7,085,173	7,101,793

Table 13 below shows the annual net usage simulation results after subtracting customer-owned DG PV from the gross usage shown in Table 12.

Table 13 Range of Annual Net Usage Monte Carlo Simulation Output, AWG Jurisdictions Scenario

Year	Minimum (MWh)	Average (MWH)	95% Sim Upper Bound (MWh	Maximum (MWh)
2020	6,509,072	6,526,785	6,533,177	6,542,852
2021	6,508,911	6,526,090	6,532,985	6,544,236
2022	6,506,267	6,525,723	6,532,862	6,542,871
2023	6,499,317	6,516,624	6,523,995	6,536,368
2024	6,509,397	6,526,701	6,533,686	6,543,901
2025	6,481,246	6,499,280	6,506,375	6,518,143
2026	6,477,896	6,492,291	6,498,721	6,509,300
2027	6,460,608	6,480,682	6,487,948	6,498,289
2028	6,459,388	6,479,816	6,488,008	6,502,760
2029	6,425,429	6,446,274	6,454,791	6,467,634
2030	6,401,034	6,425,505	6,434,893	6,449,338

A.5.c Load Study Risk Analysis

As discussed in this section, a variety of moving parts are associated with developing a load forecast. The variables considered within this load analysis include:

1. Historical hourly usage
2. Anticipated growth in overall usage
3. Distributed generation (rooftop solar) growth and output variability
4. Natural variation in day-to-day demand that may differ from historic

Items 3 and 4 present significant risk to a potential CCA because the future energy needs of the region are uncertain. The risks associated with effectively serving variable demand (and resultant variable gross revenues) are discussed further in the following sections.

B. Power Procurement Portfolio Scenario Analysis

This section discusses the framework used to develop Central Coast Power's resource plan. The Monte Carlo simulation combined the variability of all relevant power supply procurement components to estimate the short-, medium-, and long-term power procurement costs for the CCA, by geographic participation scenario and by renewable energy content scenario. The variables considered for power procurement cost include natural gas generation, utility scale renewable generation, CAISO day-ahead and real-time markets, and resource adequacy. The Monte Carlo simulation model was run 10 times for each of the eight participation scenarios and the renewable energy content (RPS Equivalent, Middle of the Road, and Aggressive) scenarios, or 2,40 runs overall. Each run of the simulation corresponds to 672 hourly calculations for a 28-day month and 744 hourly simulation calculations for a 31-day month—4,018 hourly calculations for each year of the Study period, or 40,180 hourly simulation calculations for each variable after 10 runs of the Monte Carlo model.

This section of the Study discusses in detail supply requirements, contracts, and portfolio management. Each component of the CCA supply portfolio is identified and the cost for each component is estimated and forecasted. The power procurement costs are the major operational expense for the CCA (as well as the major financial risk element) and are the cost driver for the financial pro forma and subsequent rate analysis. This section also lays the foundation for the GHG emissions analysis discussion in Section II.G.

B.1. Power Procurement Introduction

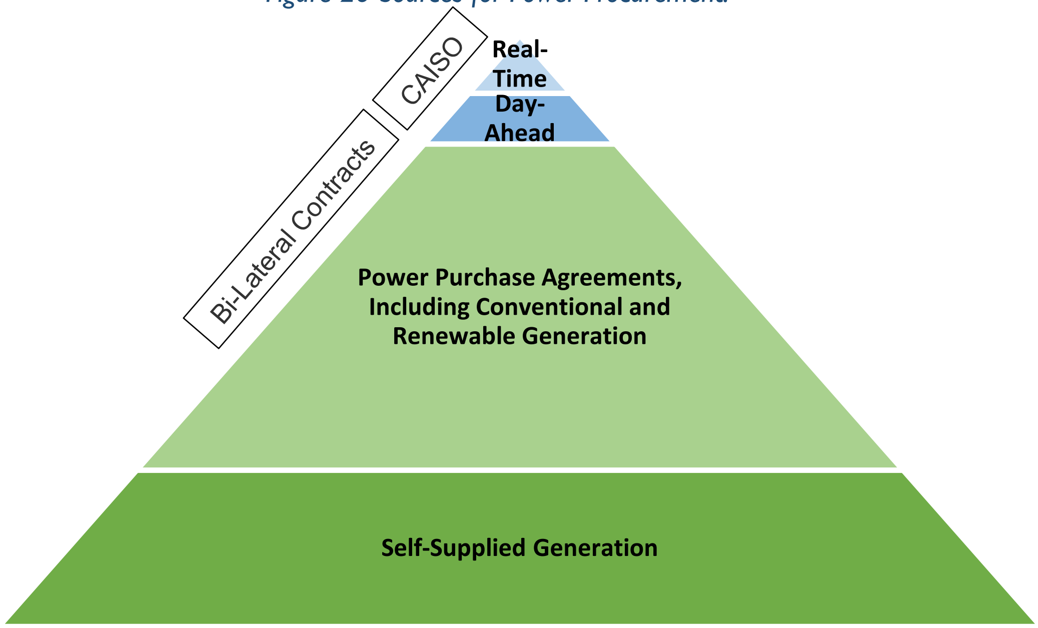
The energy supply portfolio for a CCA, like all LSEs in California, is typically comprised of three sources:

1. Self-supplied fossil-fueled, nuclear, and renewable generation from assets the CCA owns (or contractually controls);
2. PPA-procured generation through bilateral contracts with independent power producers for fossil fuel and renewable generation;
3. CAISO day-ahead and real-time market purchases.

The CAISO provides markets for day-ahead and real-time short-term energy products in the wholesale market. The day-ahead CAISO market is the forum to finalize the load forecast and either procure the additional energy expected to be required or sell any expected excess available from the supply portfolio. The real-time market then balances the day-of supply and demand and is settled at the CAISO real-time market clearing price for purchase and sale.

Figure 26 illustrates a typical power procurement strategy, where the bulk of the capacity and energy needed to serve customer load is procured in advance of actual use, and the purchase or sales of smaller amounts of incremental capacity and/or energy needed to exactly match actual customer demand and use are transacted in the shorter-term day-ahead and real-time energy markets operated by the CAISO.

Figure 26 Sources for Power Procurement.



There are essentially two commodities for electric energy. Power, or capacity, is designated as the instantaneous peak demand occurring over a time period (during the hour, month, year, etc.) and is measured in MW or kW. Energy represents the production and consumption of power over time (the flow) and is measured in MWh or kWh. In California, resource adequacy rules require 15% more power capacity than the forecast demand to ensure all demand is reliably served.

Each of these supply portfolio sources and current cost trends are discussed in this section, followed by additional discussion of the need for and cost of resource adequacy to meet CAISO and CPUC requirements. Conceptually speaking, the CCA would likely have self-supplied generation resources supplemented by PPAs and CAISO purchases.

Time of year has a significant impact on electricity demand and cost. In California, the summer peak hours occur in the late afternoon, due to air conditioning system load and agricultural processes, and are traditionally the highest demand hours of the year and the highest cost. Increasing adoption of roof-top solar PV, is starting to change this relationship, with solar production shifting the observable system peak to later in the day, when solar production ends with the setting sun. This shift of peak demand combined with an abrupt decrease in DG production creates the need for a rapid and large increase in other energy supplies or reduction in demand. Conversely, in late December the number of holiday lights switched on at sunset by daylight sensors noticeably increases demand. In response, supply portfolio managers seek more narrowly-defined, seasonal generation resources/products matched to these types of phenomenon.

B.1.a Resource Planning and Management

CCAs develop resource plans that cover multiyear periods and incorporate not only load and generation forecasts, but also energy efficiency programs and objectives. The purpose of these integrated resource plans (IRPs) is generally to:

1) Identify and confirm the assumptions used for all aspects of the IRP (to ensure proper planning across California);
2) Identify and quantify the resources needed over the planning horizon;
3) Identify and prioritize any resource preferences to be achieved such as renewable energy goals, energy efficiency objectives, procurement strategies, and constraints; and
4) Provide guidance and direction to the supply managers for procurement activities over the planned time horizon.

Electricity cannot be stored; supply must instantaneously serve demand. Storage technologies actually convert electricity into another form for future use. For example, battery storage is the use of electricity to charge a battery which can then be discharged at a future time.

For any load to be served, specific power products must be procured. These products have different characteristics depending on type (energy, capacity),[80] services (ancillary services), and market costs (CAISO uplift charges). Because electricity is consumed in real time and electric energy cannot be stored, electricity production must be matched to electric consumption instantaneously. The modern electric system is self-balancing—that is, dispatchable generation resources ramp up and ramp down generation to match load, either increasing or decreasing in real time. Increasingly, load itself is used as a balancing resource through demand response.

Managing a supply portfolio is an exercise in forecasting load behavior under various scenarios and identifying the types of energy supply contracts needed to most cost efficiently meet the load requirements over a specific period of time. Like other LSEs, most CCAs use a supply portfolio risk management approach for purchasing power products. This approach relies on a combination of fixed and/or variable cost supply options tailored to risk management. Risk is managed through diversified: supply technologies; production types; generation size and location; contract length; and the timing of contract purchases, as well as through counterparty considerations. Managing a supply portfolio is an active, daily responsibility. A CCA can self-manage this activity (i.e., active management) or outsource this function to a third-party supplier (i.e., passive management).

Risk mitigation is less effective when the supply portfolio is predominately from a single source. In the case of the supply portfolios explored in this Study, renewable energy provides between 33% and 75% of the CCA energy supply, with an option for customers to opt-up to a 100% renewable energy supply. As the renewable energy content of the portfolio increases, supply diversity decreases. Lack of portfolio diversity increases the impact of market disequilibriums associated with the dominant resource in the portfolio: in the case of CCAs, renewable energy, particularly wind and solar. Geothermal generation has predictable output similar to fossil fuel generation; solar and wind generation do not. Although the forecast accuracy for wind and solar generation is improving,[79] the variable output of these resources can result in volatile wholesale market prices as described in Section II.B.4.c, on page II-51. Absent supply portfolio diversity, a CCA must rely on alternate risk management strategies to control this risk.

CCAs looking to incorporate high levels of intermittent renewables into a supply portfolio could work with an experienced portfolio manager (and scheduling coordinator) who can forecast and manage a similarly situated supply portfolio—a portfolio that is adapted to a customer base that is also evolving in terms of rooftop solar and plug-in electric vehicle adoption. However, managing a supply portfolio with high levels of renewable generation while customer-owned DER continues to proliferate is a relatively new situation. The associated risk for the portfolio manager is materially different than it is for managing a more diversified portfolio of resources, including a greater percentage of dispatchable fossil-fueled or hydroelectric power generation.

For Central Coast Power, longer-term considerations include owning, leasing, or entering into partnerships to build renewable generation resources. Purchasing renewable generation assets would require financing, while leasing of solar or wind generation would be possible without incurring up-front costs. As renewable energy investment tax credits begin to expire, using municipal tax-exempt financing to develop local renewable generation may be a cost-effective alternative to PPAs for a CCA.[81] However, the power procurement costs modeled in this Study do not include the costs for constructing CCA-owned or leased renewable generation facilities.

B.1.b California Renewable Portfolio Standard

Under RPS, CCAs (like other LSEs) will be required to procure at least 33% renewable energy resources for their customers by 2020 and 50% by 2030.[82] Table 14 summarizes the RPS requirements in the state of California. The RPS requirements for the 2020 to 2030 period will likely be more defined once implementation rules have been established. In fact, Senate Bill 100 proposes to increase RPS to: 50% renewable in 2026 and 60% in 2030.[83]

Table 14 California Renewable Portfolio Standard Requirements

California RPS Compliance Period	Procurement Quantity Requirement
Compliance Period 3 (2017-20)	2017 retail sales x 27% 2018 retail sales x 29% 2019 retail sales x 31%
2020-2029	Annual retail sales x 33%
2030+	Annual retail sales x 50%

In addition to the amount of renewable energy required, the RPS also imposes restrictions on what types of renewable resources qualify for RPS compliance. For example, large hydro generation projects are not eligible for RPS compliance. Similarly, customer-owned DER, predominately rooftop PV, do not count toward the California RPS.[84] Instead, RPS eligible resources include: biomass, digester gas, biodiesel, landfill gas, municipal solid waste, biopower, geothermal, small hydro, conduit hydro, utility scale solar PV, solar thermal, wind, ocean/tidal, and fuel cells.[85]

Another aspect of RPS that will impact CCA supply portfolios is the "Portfolio Content Categories" shown in Table 15. Category 3 and Category 2 Renewable Energy Credits (RECs) apply to resources that do not actually deliver electricity to the CAISO balancing authority.[86] Category 3 RECs are "unbundled" from the actual energy commodity, meaning that another purchaser actually has rights to the energy, but the RPS credit stays with the REC. Category 3 RECs are being phased out from RPS eligibility: up to 25% are allowed

Per CAISO: "A balancing authority is responsible for operating a transmission control area. It matches generation with load and maintains consistent electric frequency of the grid, even during extreme weather conditions or natural disasters." The CAISO balancing authority roughly corresponds with the state of California.

in the 2011-2013 compliance period; reduced to 15% in 2014-2016; and a 10% in 2017-2020.[87] It is not yet known whether Category 3 RECs will be allowed for RPS compliance after 2020. Contracts in excess of the RPS requirement *could* include Category 3 RECs.

Table 15 Renewable Portfolio Standards Portfolio Content Categories

RPS Portfolio Content Categories[88]	Requirements
Category 1: Both energy and RECs delivered to to a California balancing authority without substituting electricity from another source	2017-2020 Minimum 75% of quantity requirement
Category 2: Both energy and RECs cannot be delivered to a CBA without substituting electricity from another source	
Category 3: Unbundled RECs only without the energy commodity, or RECs that do not meet the conditions for Category 1 and 2	2017-2020 Maximum of 10% of quantity requirement

Because the period for this Study is 2020–2030, Category 3 unbundled RECs are not used in the renewable content mix outlined under the three possible renewable procurement scenarios. Neither SCE nor PG&E use Category 3 RECs to meet current or future RPS obligations and have not used Category 2 or 3 RECs since before 2011.[89]

B.2. Power Procurement Approach

The cost of power procurement for this Study was based on analysis of the variables listed below. Each variable was analyzed to identify the average and standard deviation for any given hour of every month with average and variation used to identify the potential range of operating conditions.

- Electricity Load—based on the 2014-15 data provided by PG&E and SCE and load forecast discussed in Section II.A.5, a supply portfolio was developed for each jurisdictional and renewable supply scenario.
- Customer-Owned Solar Output—based on the customer-owned DER forecast from Section II.A.5.a and NREL PVWatts[90] analysis tool, an estimated solar output forecast was developed to simulate the effect of DG PV on net energy sales as well as hourly demand volatility.
- PPA costs for both renewable generation (Section II.B.4.b) and natural gas generation (Section II.B.4.a)—for each jurisdictional and renewable supply scenario. No operating and maintenance responsibilities (or resultant costs) associated with power procurement were included in the estimated cost of power procurement because these costs are assumed to be included in the negotiated PPA pricing.
- CAISO (Section II.B.4.c) market costs–hourly calculations of actual electricity demand were compared to PPA contracted supply and any difference was purchased or sold in CAISO markets. Historical day-ahead and real-time locational marginal pricing market pricing specific for each county was used as the basis for future price forecast and expected volatility.

B.2.a Power Purchase Agreements

PPAs are term contracts to purchase energy from either conventional fossil fuel independent power producers (generators) or utility scale renewable power producers. Generators will typically enter contractual agreements for approximately 80% of capacity to cover operations and maintenance cost and then trade the remaining capacity in the CAISO market.

In general, long-term power purchases spanning multiple years are used to meet load requirements that are predictable (e.g., base load for a supply portfolio over all forecast scenarios) at a known price or a price that is tied—or indexed—to another market pricing indicator (such as the price of natural gas). Longer-term contracts for supply tend to be at a fixed volume and a fixed price, which allows for cost certainty and stability over the contract term. Other supply contracts are procured on a shorter time frame (e.g., quarterly or monthly), when load forecasts become more accurate and other market conditions are better known or anticipated (i.e., prices are trending up or trending down). These shorter-term PPAs are used to "shape" the supply profile to better match the forecasted load behavior.

For solar PV, NREL's *Power Purchase Agreement Checklist for State and Local Governments*,[91] identifies the following advantages of PPAs as a financing mechanism to acquire renewable energy:

- No/low up-front cost; [92]
- Ability for a tax-exempt entity, like Central Coast Power, to enjoy lower electricity prices thanks to savings passed on from federal tax incentives to the system owner; and
- A reasonably predictable cost of electricity over 15–25 years.

B.2.b Resource Adequacy

Two primary commodities comprise electricity transactions in California: energy and capacity. Energy (MWh or kWh) is associated with consumption. capacity (MW or kW), for resource adequacy (RA), is associated with the ability of a resource to meet load requirements and is purchased through bilateral agreements and typically solicited through a Request for Offer process. Using the earlier explanation from Section II.A.4: a 100 MW power plant running at full production for a day produces 2,400 MWh (100 MW times 24 hours) of energy and has 100 MW of capacity. Both energy and RA capacity can be procured through the same PPA.

The RA program is a mandatory planning and procurement process to verify that adequate resource capacity is available to serve all customers in real time.

In order to ensure reliable grid operation, all California LSEs (including CCAs) must provide reserve power capacity (MW) in compliance with the RA process. The CPUC requires all LSEs to demonstrate in both monthly and annual filings purchased RA capacity commitments of no less than 115% of monthly peak demand. These RA requirements are intended to secure sufficient commitments from actual, physical resources to ensure system reliability. The CPUC's RA program establishes annual minimum capacity obligation requirements for CPUC jurisdictional LSEs on a year-ahead basis at both the system and local level. The key RA obligation is that a resource counted as "RA capacity" must either: (i) deliver energy to the LSE or bid into the CAISO energy markets; or (ii) be available to produce electricity when needed. Each day, the CAISO runs a day-ahead integrated network model and dispatches resources to meet expected demand. The CAISO can schedule designated RA capacity to provide energy as needed to maintain reliability. The RA program requires LSEs, including CCAs, to submit filings with the CPUC on a year-ahead basis (due in October) and twelve month-ahead filings (due monthly) during the compliance year verifying the requisite contracted RA capacity.

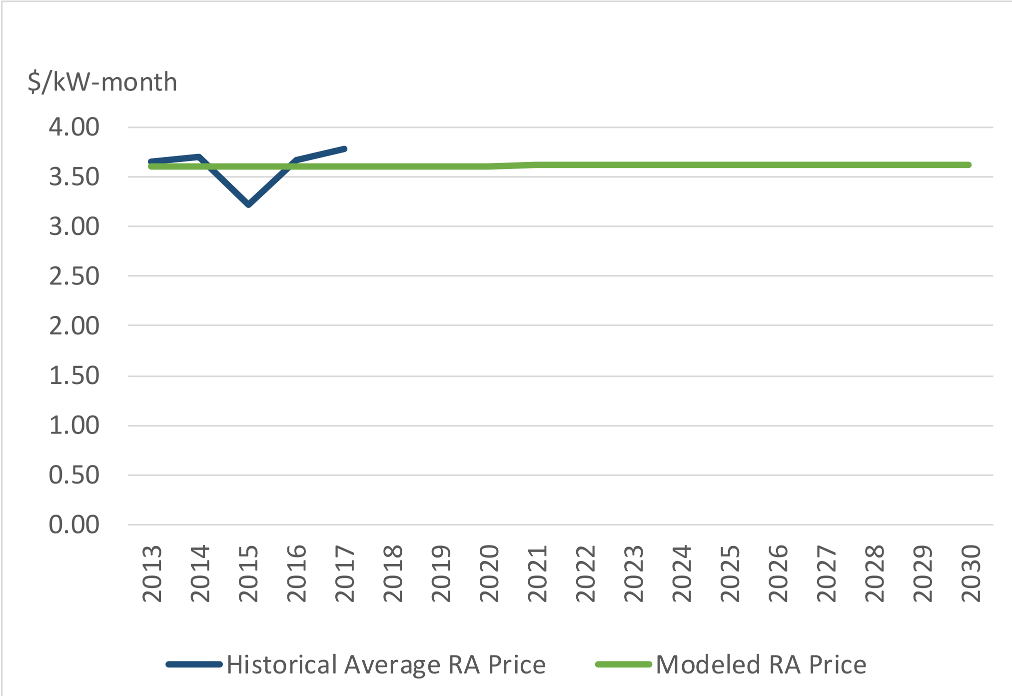
Currently no liquid market for RA capacity products exists in California and, therefore, all RA transactions occur in the bilateral marketplace.[93] The most straightforward way to acquire RA capacity is the use of "full requirements load following" type power supply contracts that provide all power (renewable and conventional, including base load and shaped load requirements), capacity (System and Local RA), distribution losses, uplift, and ancillary charges. CCAs can require RA be provided as part of PPAs and can purchase power and capacity through one solicitation. Most power marketers and all generation owners are potential suppliers of RA products. Lack of a formal RA capacity market makes price discovery difficult. However, the *2015 Resource Adequacy Report* estimates a range of capacity pricing with aggregated RA contract pricing as shown in Table 16.[94] These values, taken directly from the *2015 Resource Adequacy Report,* were used to estimate CCA costs for system and local RA. [95]

Table 16 Resource Adequacy Report aggregated RA contract prices for 2013-2014

Aggregated All RA Capacity Contracts[94]	$ per kW-Month
Weighted Average Price	$3.23
Average Price	$3.20
Minimum Price	$0.09
Maximum Price	$26.54
85th Percentile	$5.80

Average resource adequacy prices have remained relatively stable in recent years, and the projection for RA pricing through the Study period reflect that. Figure 27 shows the historical and projected RA prices used within the Study.

Figure 27 Resource Adequacy Pricing used in this Study



B.2.c Energy Storage

AB 2514, and the corresponding CPUC Storage Rulemaking (R.10-12-007 [96]), requires ESPs to acquire energy storage.[97] The CPUC has determined that this law also applies to CCAs. Thus, Central Coast Power will need to procure energy storage, which may be used to satisfy RA requirements.

The CPUC decision sets a target for LSEs to procure energy storage equal to 1% of their estimated annual peak load by 2020, with installations operational no later than 2024. Since January 2016, LSEs (including CCAs) have been required to file a report demonstrating storage compliance and describing methodologies for cost-effective projects.

For purposes of this Study, Central Coast Power CCA is assumed to maintain energy storage capacity equivalent to 1% of the annual peak load in compliance with AB 2514. Because battery energy storage (BES) is an emerging technology, an external price forecast, depicted in Figure 28 and Table 17, was used to estimate the cost of energy storage and the resulting energy imported and exported from the battery system.[98]

Figure 28 Modeled Declining Price for Energy Storage

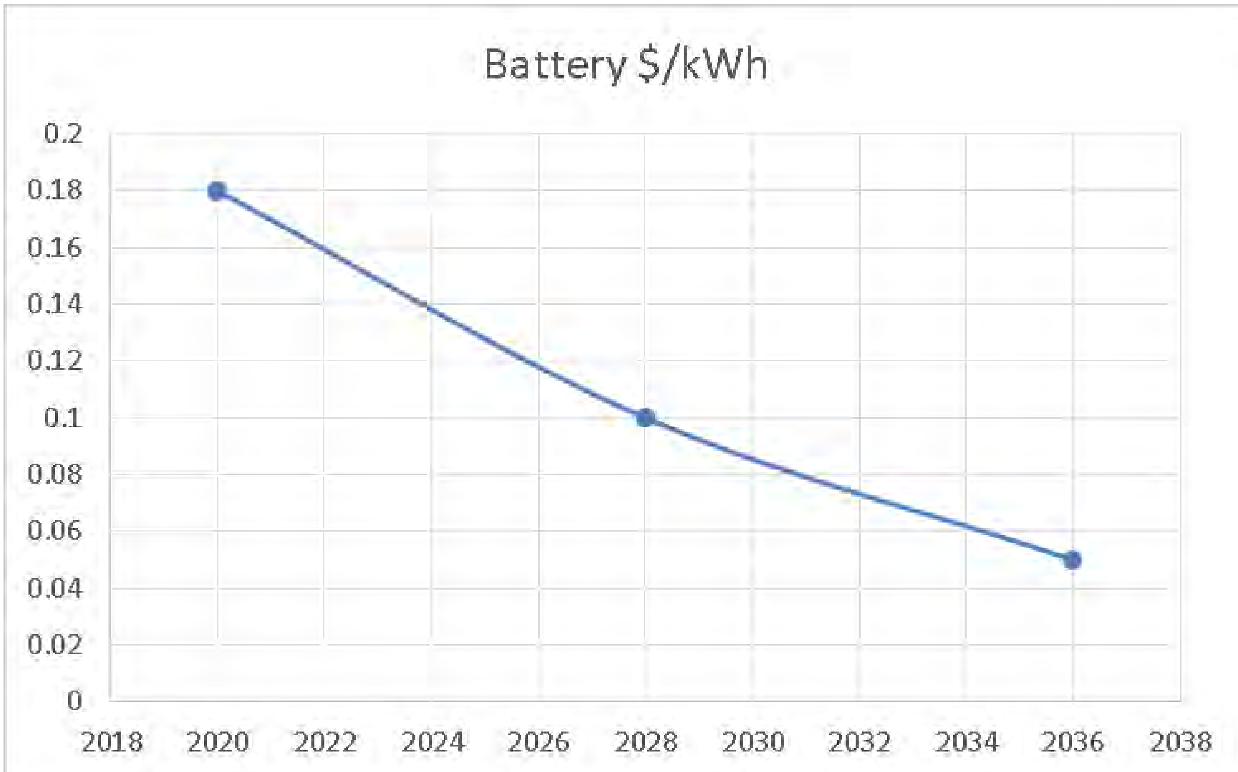


Table 17 Battery Storage Price Projection

Year	Average $ per MWh
2020	180
2021	170
2022	160
2023	140
2024	130
2025	120
2026	110
2027	100
2028	100
2029	90
2030	80

B.3. Managing the Energy Supply Portfolio

Energy procurement is similar to other commodity trading. When demand is high and delivery approaches capacity, prices are high. When demand is low and excess delivery capacity is available, pricing is low. Power market prices are continually changing, even for longer term, multiyear supply contracts. Generally, the shorter the contract term, the higher the potential for overall price volatility, but the better the opportunity to take advantages of changes in the market. The longer the contract term, the lower the potential for price volatility, but the higher the risk of being out of market in future years—either paying higher than market (bad) or lower (good). Moreover, longer term contracts tend to have initial prices higher than the current market to offset supplier risk of future market price movement. For these reasons, an effective supply portfolio should consist of a mixture of long, mid, and short term contracts.

Because power market prices are continually moving, realistic costs can only become known once Central Coast Power receives actual bid proposals. The goal of developing procurement scenarios is to identify current and potential power supply options for Central Coast Power to meet forecasted electricity demand. While electricity demand changes constantly, trends can be estimated based on historic usage patterns by time of year, day of the week (weekday vs. weekend/holiday), and weather. The variable nature of renewable resources must also be modeled. Solar output varies depending upon the time of day as well as time of year and weather, and wind generation also depends on the weather.

Central Coast Power will seek to incorporate local renewable energy into the CCA supply portfolio by potentially contracting for utility scale solar generation and/or wind generation, as well as tapping into the growing portfolio of distributed and renewable generation resources in and around the Tri-County Region. In order to develop CCA business and implementation plans and launch service, the CCA will need a thorough understanding of the renewable generation resources currently in the area as well as forecasts for new generation, both of which are beyond the scope of this Study.

B.4. Power Procurement Results

This section focuses on establishing the future costs of power supply portfolio components for Central Coast Power's three renewable energy content scenarios:

- RPS equivalent—33% renewable energy content in 2020, scaling up to 50% renewable energy content in 2030
- Middle of the Road—50% renewable energy content
- Aggressive—75% renewable energy content

Each of these supply scenarios include a customer option to opt-up to a 100% renewable supply. The Study assumption is that 2% of customers will select this 100% renewable option based on feedback from MCE that 1.9% of customers have selected the "Deep Green" option.[99] The incremental cost for customers that opt-up to a 100% renewable supply is included in the pro forma analysis (see Section II.C.4.b Power Procurement Costs for additional detail).

B.4.a Natural Gas Generation

PPAs are confidential contracts. As a result, actual contractual pricing is not available for modeling in this Study. However, multiple alternative sources of information can provide insight into the likely range of bilateral PPA prices for natural gas generation. A large portion of the annual electricity supply in California and the Tri-County Region comes from natural gas, as shown in Figure 5. Therefore, analyzing the price of natural gas sold to the electric power industry can help derive both the natural gas generation supply cost as well as a forecast of natural gas generation pricing.

EIA tracks the monthly price of natural gas sold to California electric power producers in dollars per thousand cubic feet (mcf), which is roughly equivalent to dollars per million British Thermal Units (BTU).[100]

A "heat rate" measures the efficiency of converting a fuel, like natural gas, to electricity. The California Energy Commission (CEC) 2015 Update of the Thermal Efficiency of Gas-Fired Generation in California estimates the 2014 system heat rate to be 7,760 BTU per kWh. [101] Combining these data results in an approximate natural gas supply electricity cost per MWh as shown in Figure 29.

Additionally, the monthly CAISO Market Performance Metric Catalog derives a Daily Integrated Forward Market Default Load Aggregation Point Market Implied Heat Rate as shown in Figure 30.[102] While the EIA heat rate data indicated a recent range of 7500–8000 BTU per kWh for California, the CAISO market implied heat rate for 2016 shows a range of 10,000–15,000 BTU per kWh. This 33%–87% markup is likely the difference between the natural gas supply cost and electricity sale price for independent power producers (generators) and is also reflected in Figure 29.

Figure 29 California Natural Gas Generation Cost Based on Natural Gas Price and Heat Rate Conversion

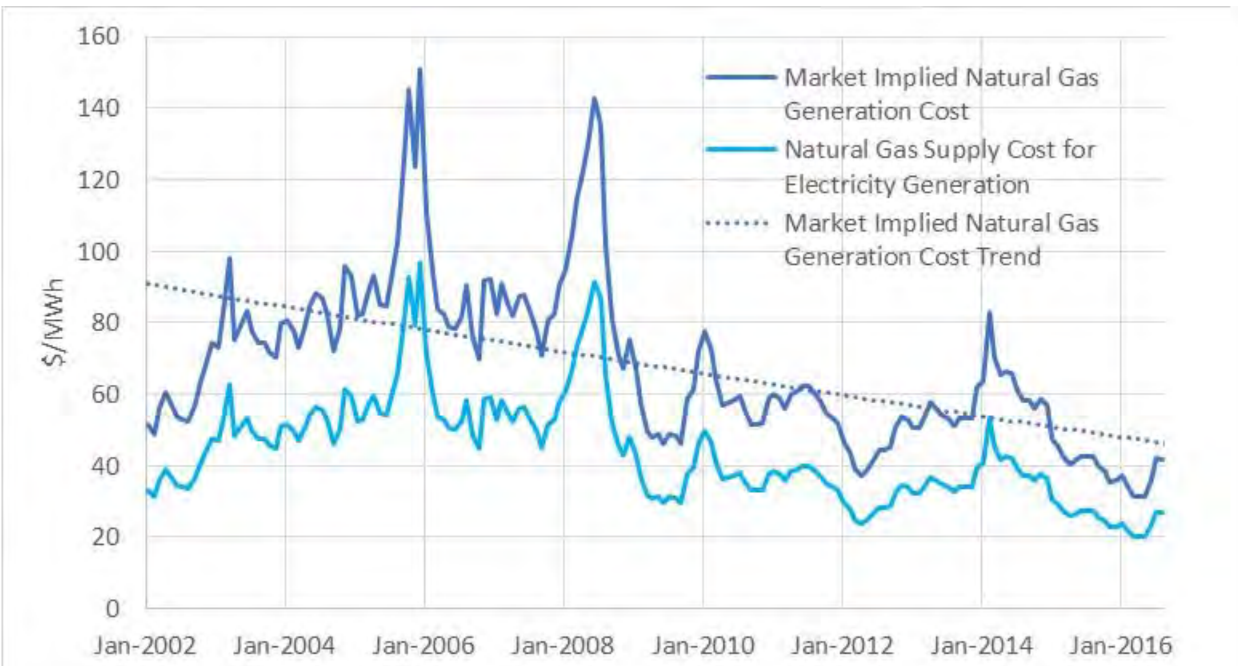
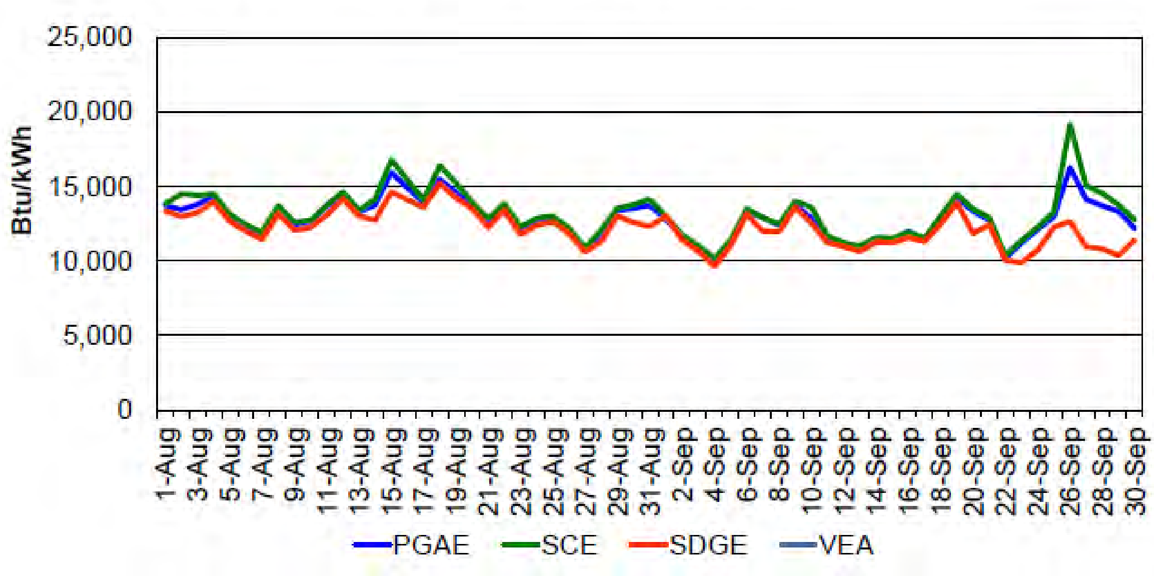


Figure 30 Replica of Market Performance Metric Catalog for August and September 2016, Daily Market Implied Heat Rate



Source "Figure 3: Daily IFM Default LAP Market Implied Heat Rate."[103]
(PGAE = PG&E, SDGE = SDG&E and VEA = Valley Electric Association)

Figure 31 and Table 18 show the natural gas generation supply cost forecast used in the Study. The standard deviation in Table 18 is based on the historical data in Figure 31 and is used in the Monte Carlo Simulation Model to estimate the cost volatility for natural gas generation. The graph combines data on the EIA California natural gas generation cost based on natural gas prices and heat rate conversion with the CAISO market implied heat rate, including an improvement in natural gas generation heat rate (efficiency) over time.

Figure 31 Natural Gas Generation Supply Cost

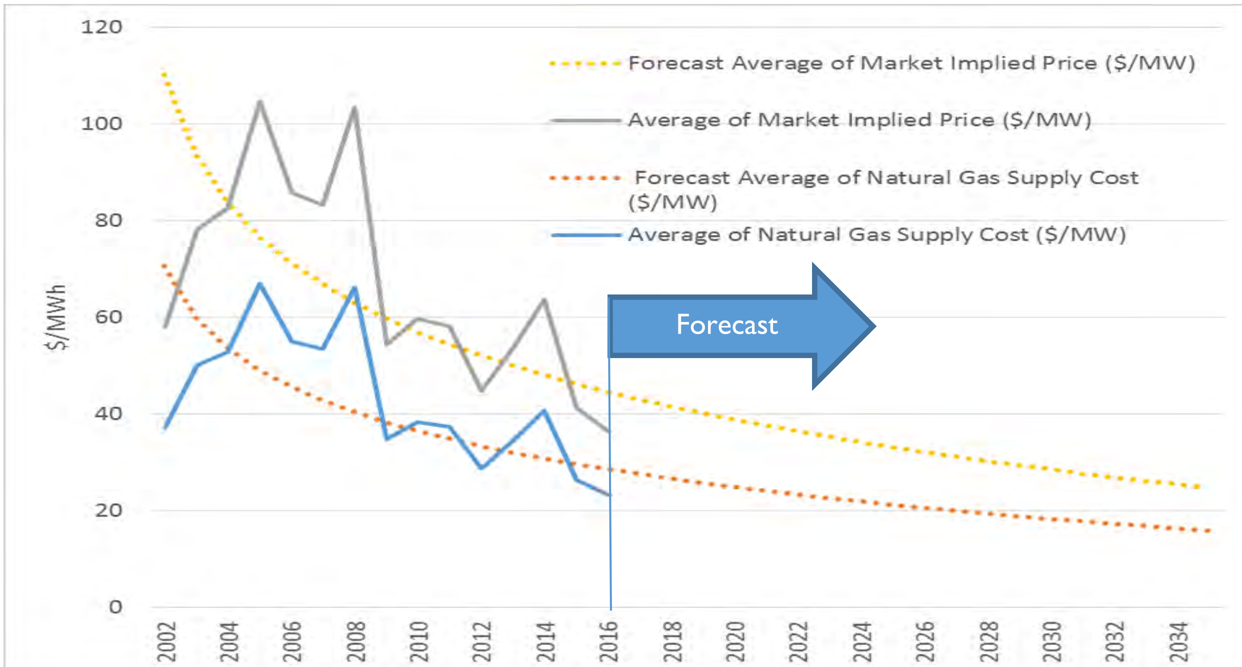


Table 18 California-Specific Natural Gas Generation Price Forecast

Year	Average $ per MWh	Standard Deviation
2020	38.83	4.61
2021	37.59	4.61
2022	36.40	4.61
2023	35.27	4.61
2024	34.20	4.61
2025	33.16	4.61
2026	32.17	4.61
2027	31.22	4.61
2028	30.30	4.61
2029	29.42	4.61
2030	28.57	4.61

Figure 31 indicates a declining price trend for natural gas generation, due to drilling technological advances, the practice of fracking, and improvements in natural gas combustion turbine efficiency.[104] The price spike in 2014 is attributable to the "polar vortex" where delivery capacity was constrained due to increased natural gas demand for heating.[105] The average market implied price projection (the yellow dotted line) is the price assumed for Central Coast Power's natural gas generation PPAs.

This natural gas price forecast was then applied to the expected annual load served by natural gas to determine the cost component of generation served by natural gas. Natural gas is assumed to serve power supply needs not served by renewables. Therefore, the overall cost for natural gas generation decreases with increasing renewable portfolio content. Tables 19, 20, and 21 present the modeled cost of natural gas generation for the AWG Jurisdictions RPS Equivalent, Middle of the Road, and Aggressive scenarios, respectively.

Table 19 Modeled Cost of Natural Gas Generation in the AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$139,245,089	$169,250,689	$180,837,295	$197,126,463
2021	$130,731,390	$158,606,149	$169,814,982	$188,282,583
2022	$120,559,317	$152,766,149	$164,343,476	$180,851,738
2023	$115,441,031	$140,016,793	$150,287,083	$164,673,487
2024	$106,497,309	$133,105,269	$143,560,163	$159,234,081
2025	$102,806,826	$126,970,082	$136,654,946	$152,558,014
2026	$91,345,901	$115,982,485	$125,632,600	$140,245,015
2027	$82,262,248	$110,093,412	$120,513,765	$137,084,111
2028	$79,926,254	$107,063,995	$116,822,322	$129,689,717
2029	$77,488,638	$97,877,220	$106,312,818	$120,087,875
2030	$68,188,927	$91,603,440	$100,887,492	$115,882,760

Table 20 Modeled Cost of Natural Gas Generation in the AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$103,589,008	$125,470,367	$133,546,567	$144,448,580
2021	$98,732,452	$121,755,754	$131,323,608	$147,576,396
2022	$90,848,473	$118,264,615	$128,828,371	$144,913,440
2023	$86,827,825	$111,391,156	$120,995,443	$135,295,859
2024	$90,525,152	$113,266,529	$123,200,097	$140,340,856
2025	$83,550,573	$104,782,969	$113,728,208	$128,673,515
2026	$78,927,138	$102,053,326	$110,366,181	$120,923,142
2027	$83,206,623	$103,144,757	$111,850,933	$126,471,226
2028	$74,445,686	$95,026,229	$103,679,791	$118,284,418
2029	$70,425,223	$93,693,683	$102,961,928	$117,572,455
2030	$72,741,003	$91,096,703	$99,426,185	$114,435,256

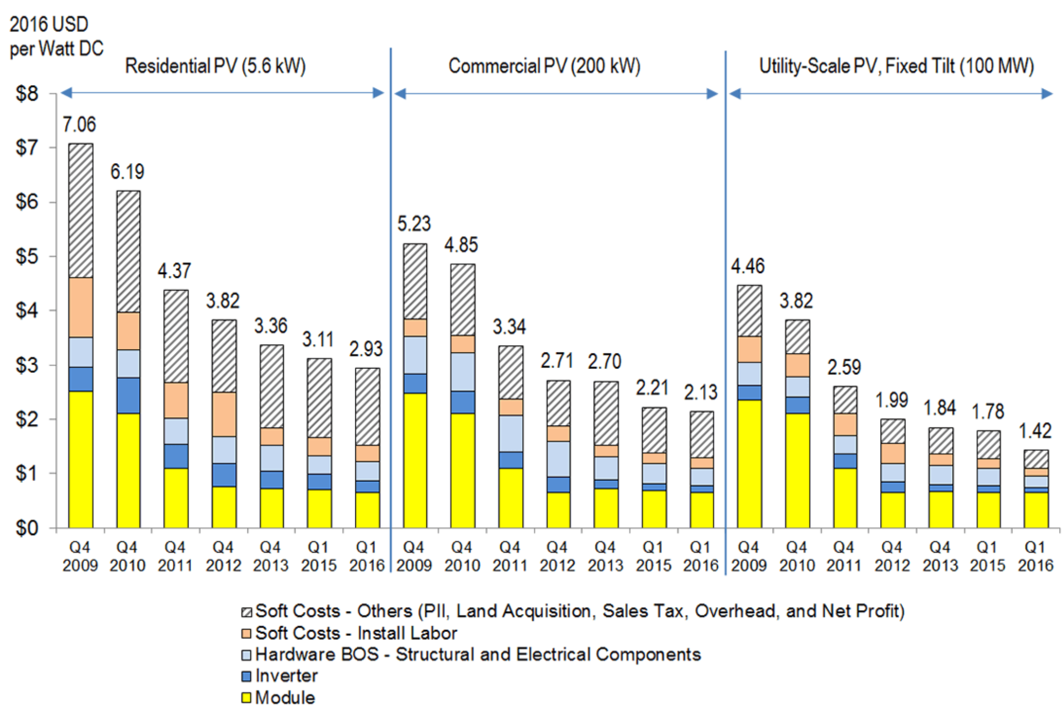
Table 21 Modeled Cost of Natural Gas Generation in the AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$53,241,795	$64,483,895	$68,989,979	$75,997,778
2021	$50,318,044	$59,714,414	$63,656,715	$70,663,616
2022	$49,114,090	$59,021,783	$63,050,398	$69,521,347
2023	$45,269,816	$55,582,607	$59,946,117	$67,225,989
2024	$44,310,204	$55,421,188	$59,776,686	$66,587,946
2025	$41,735,939	$52,741,944	$57,029,800	$63,521,366
2026	$39,906,816	$52,561,353	$57,491,242	$64,499,156
2027	$38,258,922	$49,717,116	$54,473,994	$63,508,788
2028	$38,631,411	$49,901,503	$54,421,143	$61,528,172
2029	$34,361,399	$47,502,843	$52,289,779	$59,071,174
2030	$33,207,985	$45,092,197	$49,684,248	$57,088,229

B.4.b Renewable Generation

Historical price trends indicate that the cost of renewable energy is decreasing. Indeed, the 2016 NREL U.S. Solar Photovoltaic System Cost Benchmark Report states that "utility scale (>2MW) photovoltaic systems have reached $1.42 per watt DC (Wdc), or $1.99 per watt AC (Wac), for fixed-tilt utility-scale systems, and $1.49 per Wdc (or $1.79 per Wac) for one-axis-tracking utility-scale systems."[106] The trend for NREL historical photovoltaic systems is illustrated in Figure 32.

Figure 32 Duplicate of NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016 Figure ES-1—NREL PV System Cost Benchmark Summary (inflation-adjusted), Q4 2009–Q1 2016



However, according to the CPUC Q1 2016: Biennial RPS Program Update,[114] the IOU RPS-eligible procurement costs have been increasing since 2011, as shown in Figure 33.

This disconnect between national trends and actual RPS-eligible procurement costs in California may be in part due to the RPS program itself.[107] The initial 2002 RPS applied only to California IOUs. RPS procurement costs then increased until 2008, at which point prices declined until 2011. In 2011, Senate Bill X1-2 (SBX) expanded RPS to municipal utilities, ESPs, and CCAs.[108] Prior to SBX, many of these LSEs had not aggressively pursued renewable generation. The resulting prices exhibit a classic supply and demand situation: increased demand for RPS-compliant resources could be driving up cost, due to supply constraints. Over time, however, economic theory would indicate that increased renewable resource supplies would be developed to eliminate this market disequilibrium. The Padilla Report to the Legislature for 2015 and 2016 Renewable Procurement Costs begins to show this adjustment,[109] as also depicted in Figure 33.[110]

An AB67 legislative report also speculated on the reason for the varying cost for utility scale bulk renewable generation.[111] The report hypothesizes that increases in nominal prices are related to the capital costs of the new facilities developed to meet the 20% and 33% RPS targets, resulting in higher contract costs. The report also states that decreases in RPS contract prices in terms of real dollars indicate the robust health of the renewable market in California.

The CCA forecast price in Figure 33 for renewable generation follows the relatively flat green line, which is a logarithmic non-linear regression of the other lines in the figure. The forecast price as well as standard deviation based on historical data are listed in Table 23. Factors affecting the forecast price include the uncertainty associated with the cost of utility-scale renewable energy (1 MW and above) and sources for cost estimates. As discussed in Appendix B, bringing utility scale renewable generation facilities on line impacts infrastructure and could result in additional costs that have not been modeled in this Study.

The Study used the 2016 Padilla Report, among other resources, to estimate the cost of utility scale renewable generation.[112] The forecast used in the Study captures the downward trend as of the forecast date. As the following discussion details, the forecast is not inconsistent with the updated findings of the recent 2017 Padilla Report released in May 2017, subsequent to the finalization of the Study power procurement cost forecast.

Comparing the 2017 Padilla Report's *Table B-2. Weighted Average RPS Procurement Expenditures (Bundled Energy Only) for 2016 ($/kWh)* to the 2016 Padilla Report's *Table A-2. Weighted Average TOD-Adjusted RPS Procurement Expenditures (Bundled Energy Only) for 2015 ($/kWh)*, IOU average renewable procurement costs have increased on average. However, the Study is estimating a renewable portfolio cost that is 18-20% lower for those same years. Table 22 and Figure 33 illustrate that the Padilla Report RPS costs for all three IOUs are higher than the CCA forecast price for both 2016 and 2017.

Table 22 CCA Study comparison with Padilla Report IOU Renewable Portfolio Cost for 2015 and 2016

IOU	2015 *($/kWh)*	2016 *($/kWh)*	% Change
PG&E	0.1159	0.1119	-3.45%
SCE	0.0870	0.0942	+8.28%
SDG&E	0.1179	0.1092	-7.38%
Total	0.1017	0.1041	+2.36%
Study CCA Forecast	0.0834	0.0832	-0.24%
CCA Difference Relative to IOUs	-0.0183	-0.0209	

It should also be noted that California is entering an over capacity condition for solar. Essentially, additional solar generation capacity is not needed and is no longer displacing fossil fuel generation. This is illustrated by negative pricing in the CAISO day-ahead and real-time markets and is articulated fairly well in the Los Angeles Times article: "*California invested heavily in solar power. Now there's so much that other states are sometimes paid to take it.*"[113]

Figure 33 California IOU Renewable Portfolio Standard Compliance Cost[114]

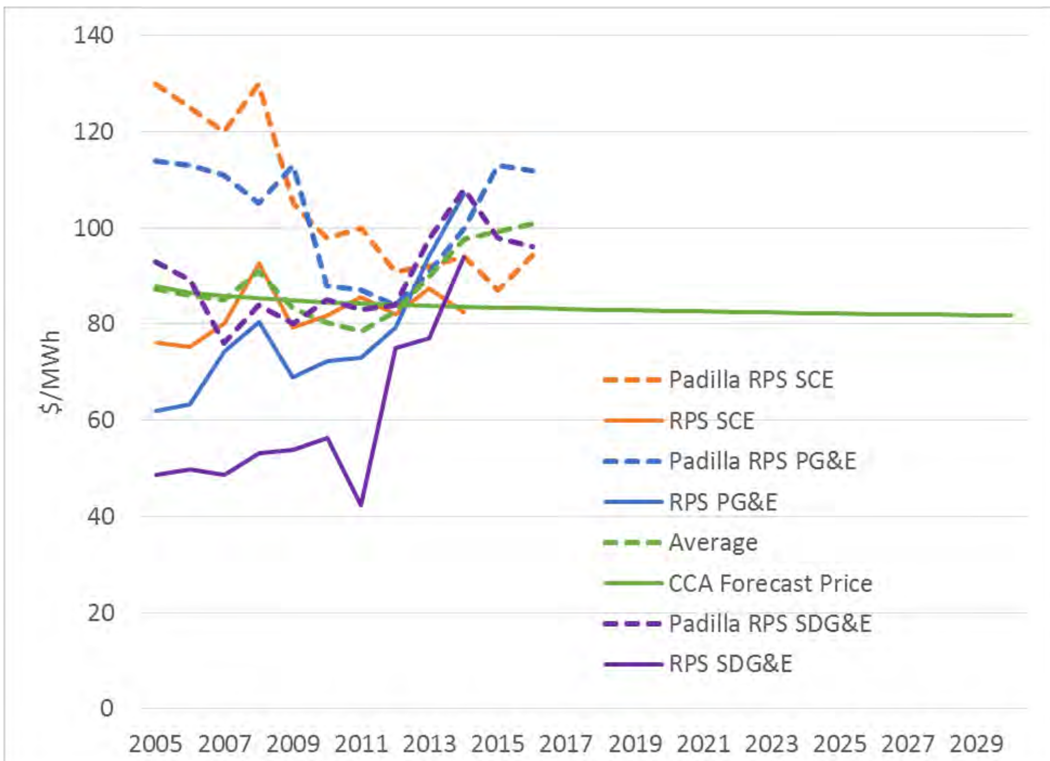


Table 23 California-Specific Renewable Power Purchase Agreement Price Forecast

Year	Average $ per MWh	Standard Deviation
2020	82.72	11.53
2021	82.61	10.98
2022	82.50	10.46
2023	82.40	9.97
2024	82.30	9.50
2025	82.21	9.06
2026	82.12	8.63
2027	82.04	8.23
2028	81.96	7.84
2029	81.89	7.47
2030	81.81	7.11

In support of the renewable power procurement cost forecast, data was also examined from the EIA's Annual Energy Outlook 2017,[115] which provides estimates of renewable generation costs on a regional basis. This data is used by utilities, energy consultancies, and others to help understand current and future energy-related pricing trends and is based on real-world project construction, financing, ownership, and ongoing operations and maintenance costs. Table 24 shows the various costing components for a new, greenfield solar photovoltaic project and a new wind project. This cost data supports all-in pricing at around $67 per MWh for wind resources and $101 per MWh for solar PV resources.

Table 24 Energy Information Administration Cost Estimates for New Wind and Solar Energy Resources in California

Description	Wind Farm – Onshore	Utility-Scale Photovoltaic
Configuration	100 MW; 56 turbines at 1.79 MW each	20 MW, Alternating Current, Fixed Tilt
Installation Type	Greenfield Installation	Greenfield Installation
Total Capacity (MW)	100	20
Capacity Factor (National Average, Jan. 2016-Apr. 2017)	36.59%	26.76%
Total Project Cost, California-Mexico Region ($ per kW-installed)	$2,010	$2,578
Total Project Cost, California-Mexico Region ($)	$201,000,000	$51,560,000
Variable O&M ($ per MWh)	$ -	$ -
Fixed O&M ($ per kW-year)	$46.71	$21.66
Weighted Average Cost of Capital (%)	5.50%	5.50%
Debt Finance Term (years)	20	20
Financing Costs per Year ($)	$16,819,545	$4,314,506
Fixed O&M Costs per Year ($)	$4,671,000	$433,200
Total Project Costs per Year ($)	$21,490,545	$4,747,706
Energy Production per Year (MWh)	320,528	46,884
Per Unit Cost ($ per MWh)	**$67.05**	**$101.27**

The Advisory Working Group contacted other operating California CCAs in May and June of 2017 to discuss power procurement and current pricing for various generation resource types. Indicative pricing was provided to the Advisory Working Group, and has been summarized in Table 25. *This material is for informational purposes only—prices have not been confirmed nor have the terms of the PPAs been reviewed. As such, the Study authors make no assurances as to the validity or comparability of this data.*

Table 25 Observed Pricing Responses Provided to the AWG by Operating CCAs, June 2017

Generation Resource Type	Procurement Cost ($ per MWh) and Notes
Natural Gas	$28-38 for 1 to 3-year terms; average mid-$30s
Greenhouse Gas-Free, Large Hydro	$36-$39 for 1 to 3-year terms; one CCA is starting to see some shortages for GHG-free resources
Category 1 Renewables	$40-$51 for 1 to 3-year terms; average high $40s
Category 2 Renewables	$40-$43 for 1 to 3-year terms; starting to see some shortages for Category 2 RECs

Based on the above research, the unitized renewable price forecast developed for the Study was applied to the expected load served by renewables to determine the cost component of renewable generation. In the case of the RPS Equivalent scenario, the total cost of power grows over time as the percentage of renewable generation increases. Conversely, since the portion of renewable generation in each portfolio is held constant for the Study term, the two other scenarios roughly follow the same slightly downward trend as the green line in Figure 33. Tables 26 through 28 show the range of expected renewable generation costs by renewable energy content scenario for the AWG Jurisdictions scenario.

Table 26 Modeled Cost of Renewable Generation in the AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$143,379,816	$181,801,533	$196,689,853	$219,027,339
2021	$151,059,210	$185,987,783	$199,942,458	$224,148,276
2022	$155,296,128	$189,809,644	$204,353,126	$225,312,676
2023	$157,270,099	$202,633,033	$219,566,210	$241,069,027
2024	$166,212,134	$209,833,461	$225,437,803	$250,068,046
2025	$176,061,352	$216,761,840	$231,216,476	$249,842,300
2026	$187,411,633	$227,936,694	$243,667,131	$267,849,026
2027	$195,122,178	$236,280,450	$253,211,792	$284,335,068
2028	$207,035,717	$248,147,502	$262,434,651	$282,884,000
2029	$213,393,188	$251,245,802	$265,720,152	$285,155,626
2030	$228,521,707	$260,744,538	$273,888,963	$293,475,523

Table 27 Modeled Cost of Renewable Generation in the AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$216,957,092	$266,893,324	$288,189,476	$319,173,443
2021	$208,734,612	$269,012,875	$290,231,883	$321,782,930
2022	$217,418,240	$267,623,580	$288,051,396	$319,291,812
2023	$216,589,938	$264,168,987	$284,263,100	$318,296,710
2024	$220,029,177	$265,884,630	$284,444,136	$316,221,927
2025	$214,213,671	$261,853,398	$281,524,574	$310,924,150
2026	$215,853,983	$259,389,698	$276,999,895	$307,945,694
2027	$223,522,767	$262,736,273	$278,949,304	$304,951,208
2028	$213,260,110	$258,113,525	$275,119,338	$301,038,190
2029	$213,581,122	$259,756,831	$276,310,757	$298,216,837
2030	$228,754,937	$262,322,591	$276,175,941	$298,680,162

Table 28 Modeled Cost of Renewable Generation in the AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$334,686,400	$409,775,610	$439,033,141	$488,710,784
2021	$310,444,916	$396,775,029	$430,946,696	$482,951,156
2022	$310,530,238	$395,532,527	$429,223,396	$484,773,037
2023	$319,260,486	$400,557,376	$429,050,899	$473,618,640
2024	$313,921,032	$395,016,358	$425,690,432	$471,311,269
2025	$330,835,607	$397,192,015	$424,153,732	$467,250,237
2026	$346,357,128	$403,470,157	$426,086,228	$462,259,516
2027	$342,797,323	$398,689,959	$423,063,381	$468,413,673
2028	$333,008,149	$396,088,396	$420,235,383	$456,044,056
2029	$334,695,458	$389,232,455	$410,352,834	$441,218,689
2030	$337,654,207	$387,299,791	$405,808,005	$434,848,026

As renewable penetration increases, system costs will likely increase due to infrastructure upgrades, reliability requirements, storage, and other changes needed to support these intermittent energy resources. However, such costs have not been included in the energy supply portfolio pricing. For example, since solar output follows the same local pattern, as more solar generation capacity is added to the system, the value of that capacity diminishes. When the capacity of renewable generation is sufficient to meet daytime electricity demand, natural gas generation will still be required, perhaps at very low output, to provide local and system reliability reserve, area frequency and voltage support, and generation when renewable output is less than expected or during non-daylight hours. When natural gas-fired generation output is low, its effective efficiency is suboptimal, increasing operating cost. The value proposition—both economic and operational—for natural gas-fired generation will change due to increasing renewable energy resources, resulting in cost uncertainty for future supply portfolio.

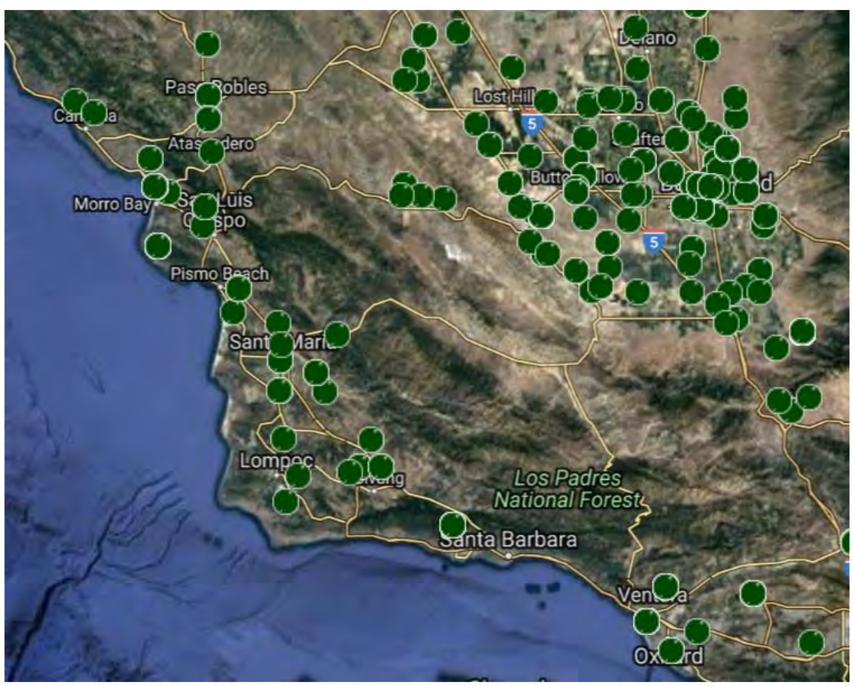
A large penetration of renewable generation impacts market price volatility. When renewable generation exceeds demand, CAISO prices will be negative, requiring energy storage imports (charging), demand response, and potential curtailment of renewable generation to balance electricity supply and demand. The dynamic of this changing economic landscape for power supply related to the increase in renewable generation resources is further discussed in Appendix B. None of these impacts have been modeled in the Study.

B.4.c California Independent System Operator Market

A CCA, like all LSEs, would use self-generation resources and PPAs to provide the majority of electricity to serve customer needs. However, load forecasts are never perfect, and PPAs will never exactly align with actual electricity demand and usage. The CAISO day-ahead market (DAM) and real-time market (RTM) function to balance supply and demand for participating LSEs while also providing transmission system voltage and frequency regulation. This section discusses how pricing for CCA supply from day-ahead and real-time markets was determined.

CAISO uses locational marginal pricing to calculate the cost to deliver electricity to specified locations. The local cost of electricity varies based on generation price and proximity to the generation resource due to both line losses and congestion on transmission infrastructure.[116] The Tri-County Region is served by multiple pricing nodes (pNodes) with different marginal pricing, as can be seen in the CAISO market price map illustrated in Figure 34.[117]

Figure 34 March 15, 2017, CAISO Locational Marginal Pricing Map for the Tri-County Region



Using a map of the region in combination with the CAISO market price map, pNodes were identified (listed in Table 29) and historic CAISO day-ahead and real-time energy costs within the Tri-County Region were analyzed. For each geographic participation scenario, the analysis looked at pNode data at the county level; for example, the AWG Jurisdictions participation scenario used data for pNodes from all three counties, while the City of Santa Barbara scenario was modeled with just the data for Santa Barbara

County pNodes.

Table 29 CAISO pNodes Identified within the Tri-County Region

CAISO pNodes Identified within the Region					
San Luis Obispo County		Santa Barbara County		Ventura County	
ATASCDRO_6_N001	MORROBAY_2_N001	BUELLTON_1_N001	LMPC-CTY_1_N001	MANDLY1G_7_B1	ORMOND2G_7_B1
BAYWOOD_6_N001	MORROBAY_2_N015	BUELLTON_1_N003	MANVILLE_1_N001	MANDLY1G_7_N002	OXGEN_7_B1
CALLENDR_1_N001	MORROBY_1_N001	DIVVIDE_1_N001	PALMR_1_N001	MANDLY2G_7_B1	OXGEN_7_B1
CAMBRIA_6_N001	OCEANO_1_N001	DIVVIDE_1_N012	PURISIMA_1_N001	MANDLY2G_7_N002	PROCGEN_7_B1
CARRIZO_1_N001	OCEANO_1_N004	FAIRWAY_1_N001	SISQUOC_1_N001	MANDLY3G_7_B1	PROCGEN_7_B1
CAVLSRGN_7_B1	PERRY_6_N001	FAIRWAY_1_N002	SISQUOC_1_N020	MANDLY3G_7_N001	SCLARA_6_N001
CAYUCOS_6_N001	PSARBLS_6_N001	GOLETA_6_N002	SNTAYNZ_1_N001	MOORPARK_6_N001	SCLARA_6_N008
CAYUCOS_6_N006	PSARBLS_6_N005	GOLETA_6_N003	SNTAYNZ_1_N002	MOORPARK_6_N005	SCLARA_6_N008
DIABLOCN_2_N001	PSARBLS_6_N007	GOLETA_6_N004	STMARIA_7_N101	MOORPARK_6_N006	WILLAMET_7_B1
FOOTHILL_1_N001	SANMIGL_6_N001	GOLETA_6_N022	SURF_1_N009	MOORPARK_6_N008	WILLAMET_7_B1
GOLDTREE_1_N001	T0239_7_N002	GOLETA_6_N100	ZACA_1_N001	ORMOND1G_7_B1	
GOLDTREE_1_N002	TEMPLE21_7_N002	GOLETA_6_N200			
MESA-PGE_1_N036	TEMPLETN_2_N001				
MORRO3_7_B1	TEMPLETN_2_N008				
MORRO4_7_B1	TOPAZC1_7_N021				
MORROBAY_2_B1					

Day-Ahead Market Locational Marginal Pricing

A portion of the CCA supply portfolio would be procured in the CAISO day-ahead market. The pricing for this market is posted on a platform known as the Open Access Same-time Information System (OASIS).[118] CAISO day-ahead market prices obtained from OASIS for January 1, 2013–October 31, 2016, showed significant variability and volatility when compared to the range of likely costs for the PPA contracts shown in Figure 33. Figure 35 through Figure 38 illustrate the maximum, average, and minimum range for CAISO day-ahead pricing for the region from January 1, 2013 to October 31, 2016, as summarized in Table 30. With negative pricing, the CAISO has excess generation that cannot go offline and will pay to either have a generator curtail output or incentivize a market participant to use more energy. The day-ahead price of $1,750 per MWh translates to $1.75 per kWh. The average cost for CAISO market pricing has been relatively stable historically. However, price volatility is increasing. Real-time prices can be above $1,000 per MWh or below -$100 per MWh in any hour of any month. Therefore, a beta distribution was used in the Monte Carlo simulation model to simulate the range of CAISO market prices and assumed steady state average, maximum, and minimum prices. In the Monte Carlo model, each hour of each month used specific data for that hour, but for brevity Table 30 lists the annual average, minimum, and maximum.

Table 30 CAISO Day-Ahead Input Data for AWG Jurisdictions Scenario, Years 2020-2030

Years	Average $ per MWh	Minimum $ per MWh	Maximum $ per MWh	Standard Deviation
2020-2030	37.98	(174.40)	1,899.56	11.90

Figure 35 through Figure 38 illustrate the volatility of recent day-ahead market activity. The outliers in pricing are likely the result of either significant projected underproduction of renewable generation (possibly a cloudy day), which makes the price go higher, or a negative pricing structure that incentivizes reduction in generation. Because the CAISO locational marginal pricing varies based on generation price and proximity to the generation resource, transmission capacity or generation contingencies likely account for the CAISO aggregated pNode price differences between the counties. The exposure to CAISO market volatility can have significant impact on LSE finances and the associated risk must be managed accordingly. Additionally, the variability of both customer-owned DG PV and the LSE renewable portfolio result in variable supply as well as increasingly variable demand with increasing exposure to CAISO price spikes:

- When renewable generation produces more than expected relative to electricity demand, the CAISO market prices can be near zero or negative and the excess CCA supply would be sold into the CAISO market at that relatively low market price.
- When renewable generation produces less than expected relative to electricity demand, the CAISO market price can spike to over $1,000 per MWh, and the CCA would cover this shortfall through the CAISO markets at the relatively high market price.

The three counties have similar pricing for the majority of the January 2013 – October 2016 time period analyzed. However, unique county-specific price spikes occur such as the maximum prices for June, hour 19:00 for San Luis Obispo. These spikes illustrate the changes that occur under locational marginal pricing when an extreme mismatch occurs between supply and demand, caused by transmission constraints, an unexpected generation outage, or significant variation in renewable output relative to the forecasted demand.

Figure 35 Hourly CAISO Day-Ahead Distribution Load Aggregation Point for January–March

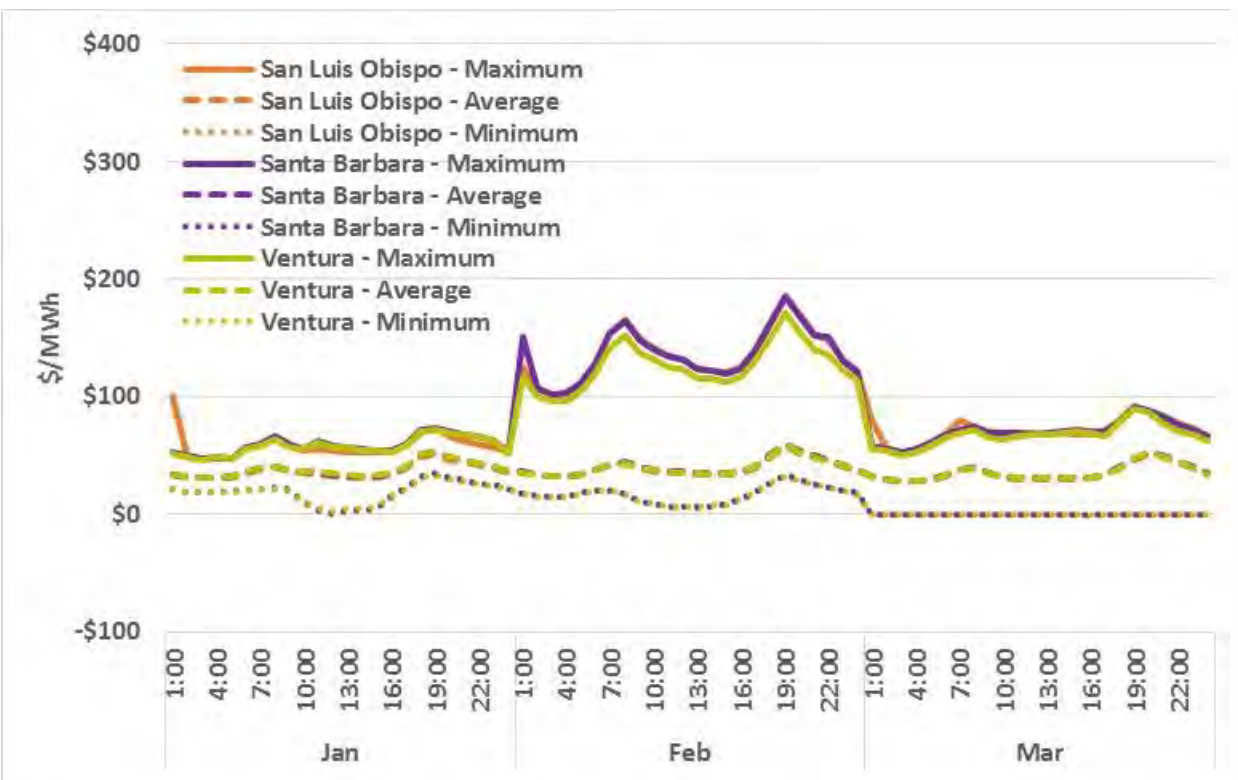


Figure 36 Hourly CAISO Day-Ahead Distribution Load Aggregation Point for April–June

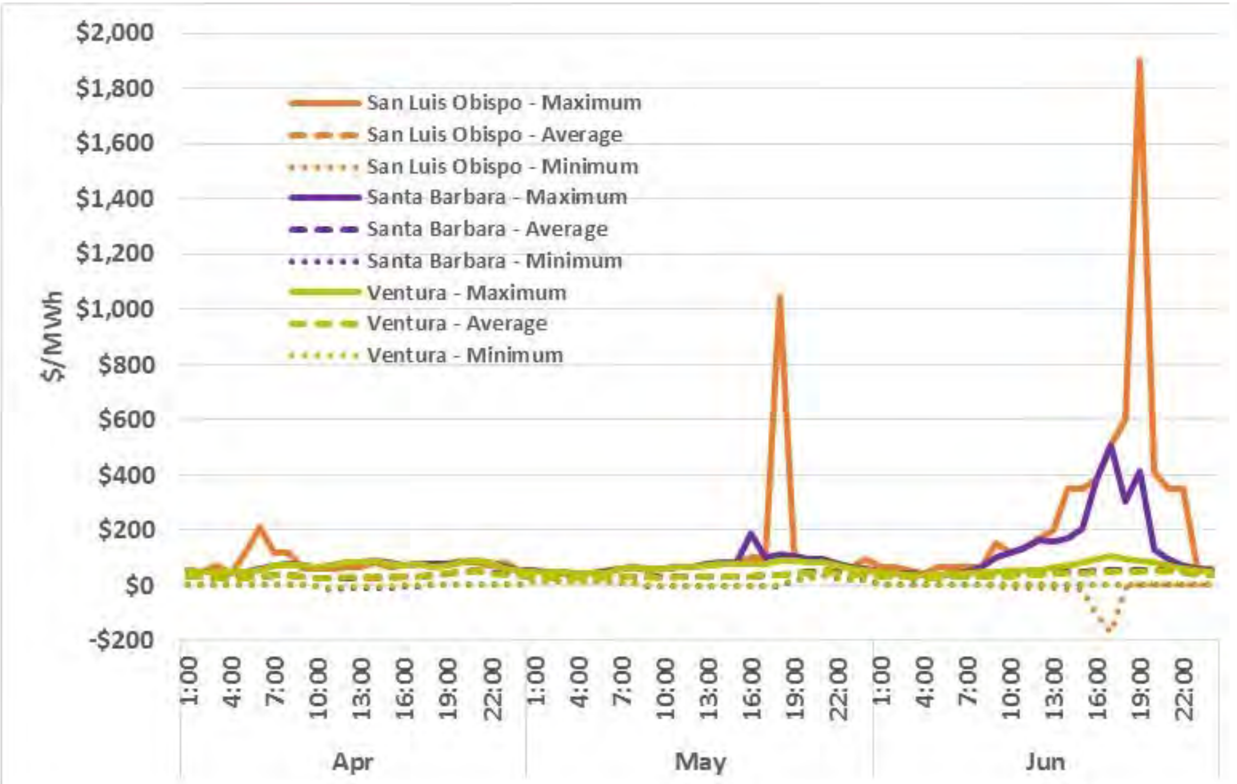


Figure 37 Hourly CAISO day-ahead Distribution Load Aggregation Point for July–September

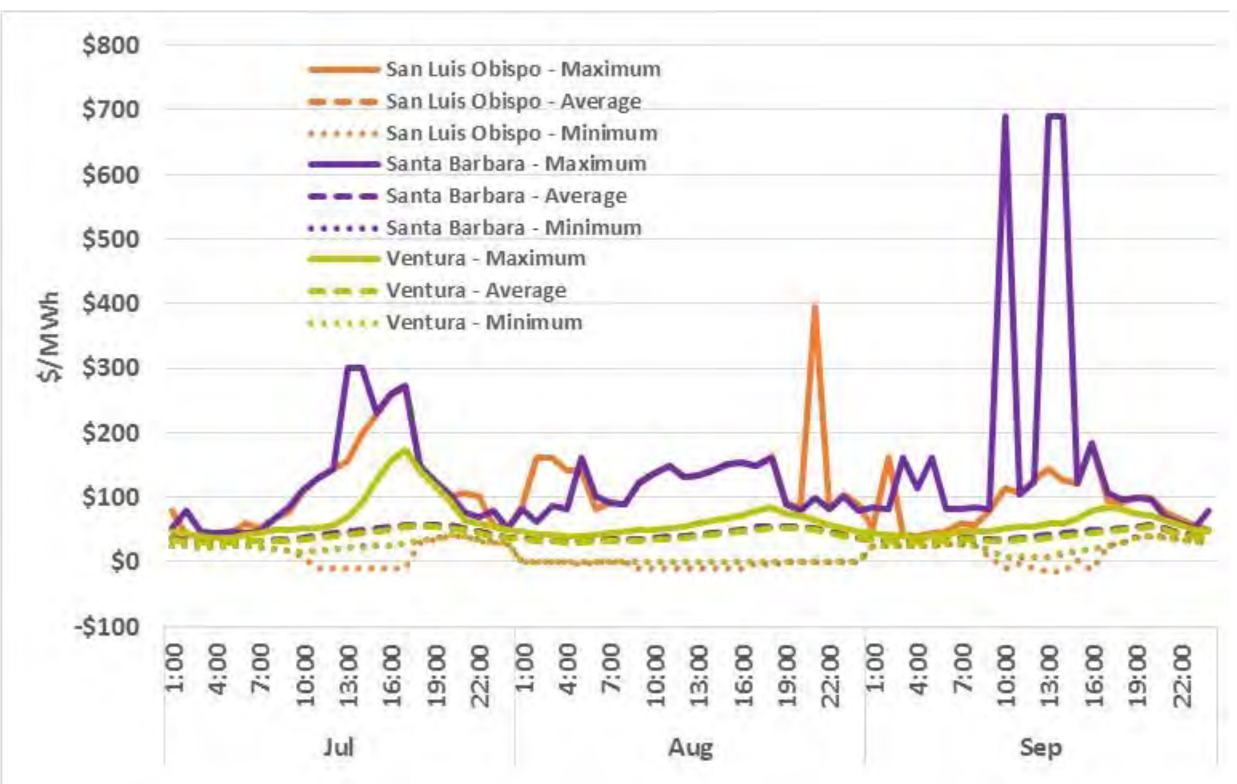
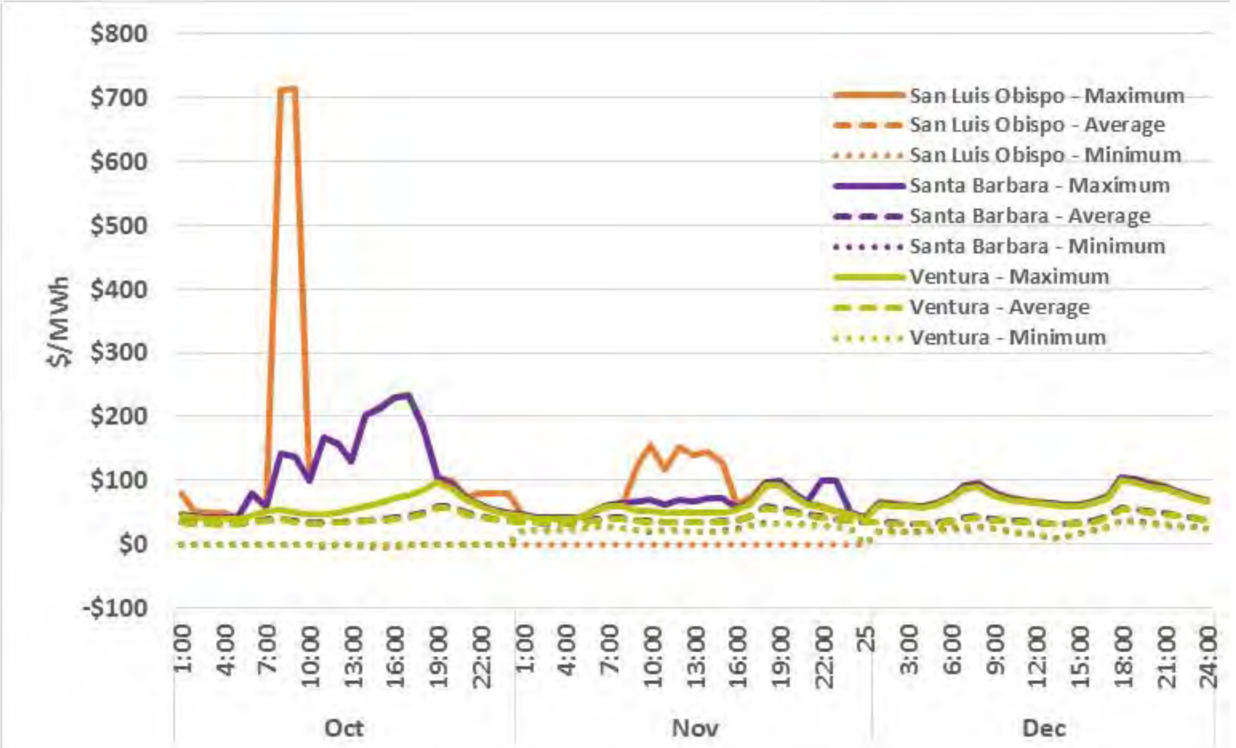


Figure 38 Hourly CAISO day-ahead Distribution Load Aggregation Point for October–December



The CAISO day-ahead market prices were then modeled with a beta distribution, and matched to the simulated results of the load study and generation profile for each jurisdictional scenario. In some instances, energy would be sold into the market, while in others, energy would be purchased from the market. The results of the day-ahead market simulation are displayed in Tables 31 through 33 for the AWG Jurisdictions scenario by renewable energy content scenario. Note that parentheses indicate negative pricing where the market would pay the CCA.

Table 31 CAISO Day-Ahead Market Simulation Results for the AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$(782,703)	$496,462	$1,008,809	$1,794,474
2021	$(326,593)	$781,961	$1,241,638	$1,915,714
2022	$(1,156,523)	$463,364	$1,064,678	$1,917,919
2023	$(897,655)	$335,270	$879,218	$1,794,848
2024	$(746,768)	$578,230	$1,158,947	$2,201,839
2025	$(837,444)	$503,841	$1,034,448	$1,897,057
2026	$(911,411)	$535,046	$1,107,672	$2,174,523
2027	$(867,324)	$590,808	$1,153,922	$2,071,892
2028	$(891,317)	$562,713	$1,189,888	$2,216,426
2029	$(1,050,275)	$602,448	$1,281,826	$2,182,417
2030	$(1,273,136)	$444,701	$1,046,101	$1,860,513

Table 32 CAISO Day-Ahead Market Simulation Results for the AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$(1,144,769)	$624,902	$1,321,165	$2,414,543
2021	$(1,061,455)	$468,620	$1,036,741	$2,018,478
2022	$(1,003,559)	$695,366	$1,317,907	$2,215,105
2023	$(1,125,002)	$508,308	$1,153,233	$2,137,871
2024	$(696,908)	$763,357	$1,371,151	$2,380,994
2025	$(1,084,303)	$567,575	$1,219,601	$2,201,057
2026	$(1,026,905)	$572,704	$1,201,340	$2,164,468
2027	$(1,097,596)	$581,008	$1,286,675	$2,274,447
2028	$(1,034,693)	$654,987	$1,351,876	$2,398,887
2029	$(1,539,197)	$349,161	$1,043,074	$2,088,167
2030	$(1,083,127)	$664,385	$1,372,612	$2,599,440

Table 33 CAISO Day-Ahead Market Simulation Results for the AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$(1,999,177)	$815,106	$1,793,919	$2,981,462
2021	$(1,775,156)	$477,631	$1,352,320	$2,619,650
2022	$(1,929,238)	$371,183	$1,256,068	$2,313,005
2023	$(1,573,683)	$674,674	$1,638,900	$3,131,801
2024	$(1,992,959)	$494,896	$1,451,135	$2,725,549
2025	$(2,011,020)	$534,100	$1,464,740	$2,615,233
2026	$(2,125,615)	$401,427	$1,405,034	$2,975,555
2027	$(1,545,628)	$565,319	$1,428,719	$2,813,476
2028	$(1,845,725)	$552,970	$1,512,368	$2,795,287
2029	$(1,621,968)	$603,090	$1,505,020	$3,017,904
2030	$(1,611,973)	$499,381	$1,369,496	$2,516,621

CAISO Real-Time Market Pricing

A portion of the CCA supply portfolio will also be procured in the CAISO real-time market. The real-time market is comprised of multiple market processes and market products. The hour-ahead scheduling process is used to dispatch non-dynamic system resources to meet near-term system balancing requirements. Ancillary services—market products that serve the real-time balancing needs for electricity supply and demand—are paid for in this market as well.

Real-time market costs for the CCA were estimated utilizing the real-time 5-minute interval locational marginal pricing data from CAISO OASIS.[119] As can be seen in Figure 39 through Figure 42, the volatility and price magnitude of the real-time market is significantly greater than that of the day-ahead market. As with the day-ahead pricing, the real-time pricing indicates stable average pricing with volatility around the average. The Monte Carlo simulation used specific data for each hour of each month, while Table 34 illustrates annual data for brevity.

Table 34 CAISO Real-Time Input Data for the AWG Jurisdictions Scenario, Years 2020-2030

Years	Average $ per MWh	Minimum $ per MWh	Maximum $ per MWh	Standard Deviation
2020-2030	35.88	(1,276.58)	4,337.44	60.83

Similar to the day-ahead market, the three counties exhibit similar average prices, and all exhibit extreme price peaks and valleys. During the January to March timeframe, Ventura experienced price spikes above $2,000 per MWh and San Luis Obispo experienced price spikes between $1,000 and $1,500 per MWh, while Santa Barbara aligned with either Ventura or Santa Barbara. For the balance of the months, with a few exceptions, the three counties exhibit similar maximum prices of between $1,000 and $2,000 per MWh. For the purposes of this Study, CAISO price volatility and market exposure due to variable output renewable resources represent risk for CCA operational costs.

Figure 39 Maximum, Average, and Minimum CAISO real-time pricing for January–March

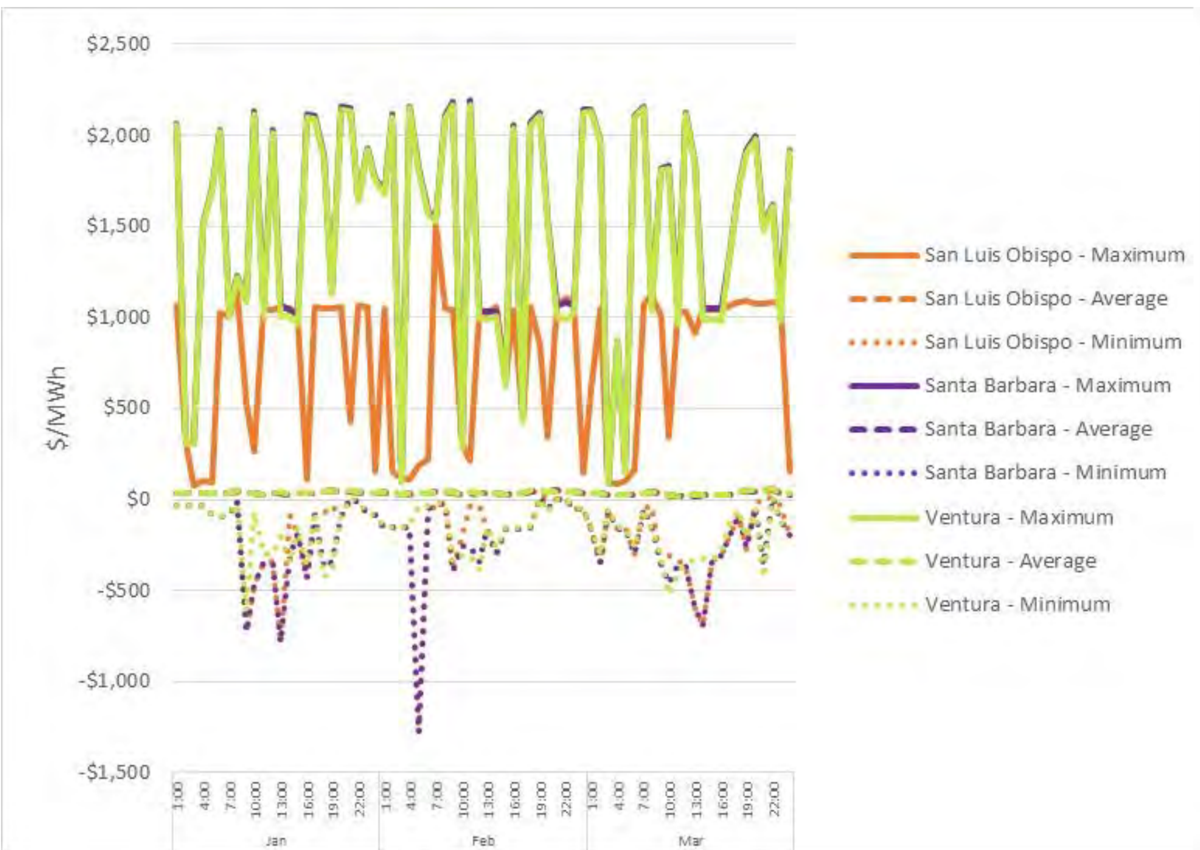


Figure 40 Maximum, Average, and Minimum CAISO real-time pricing for April–June

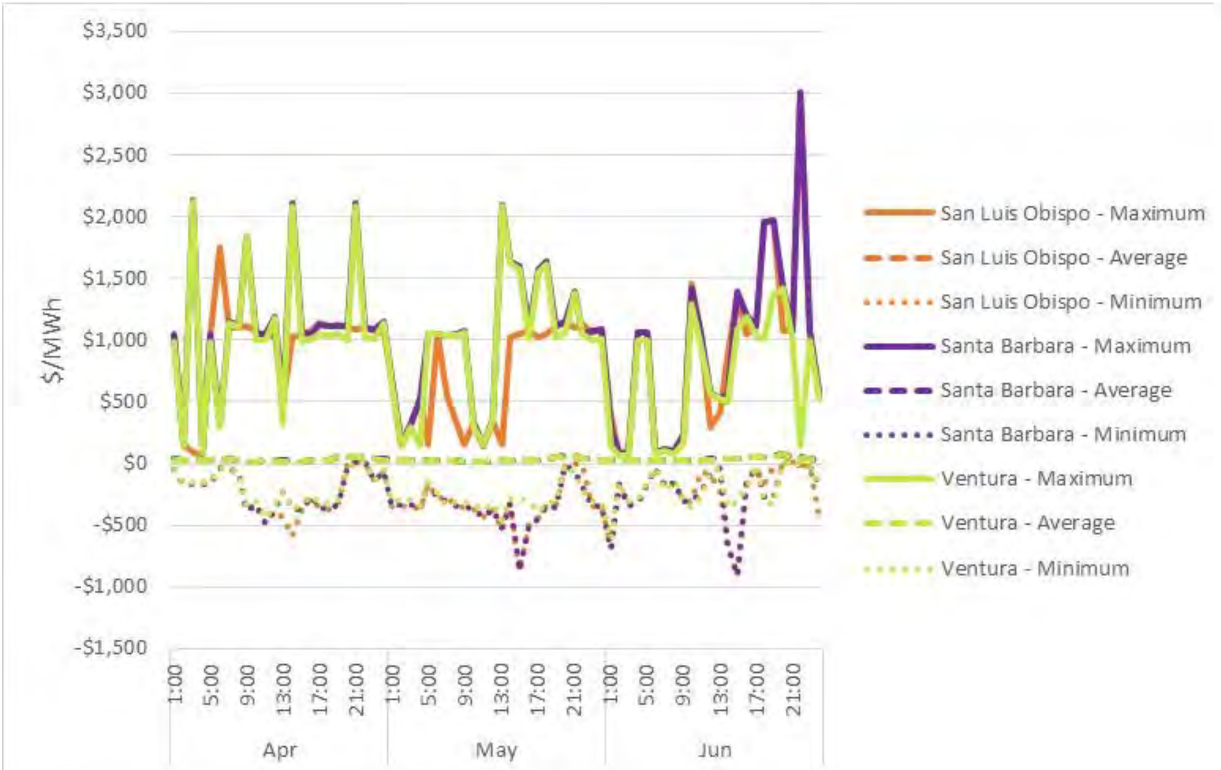


Figure 41 Maximum, average, and minimum CAISO real-time pricing for July–September

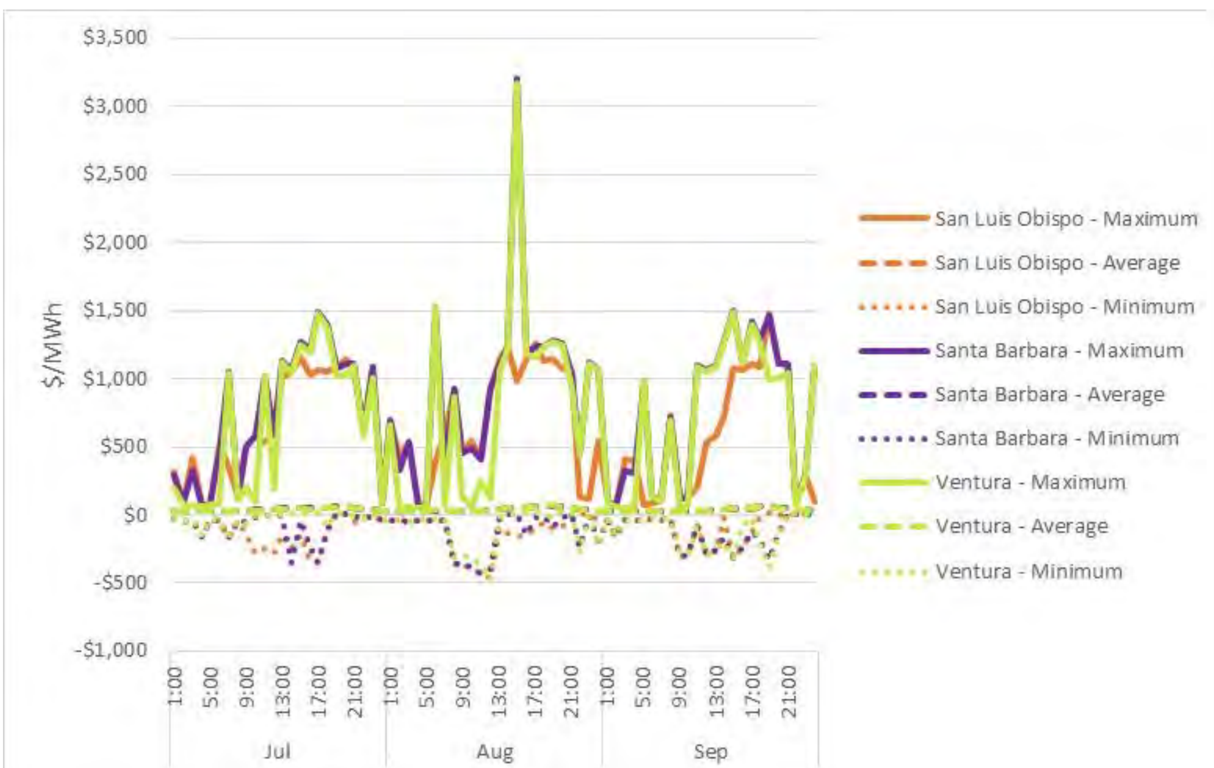


Figure 42 Maximum, Average, and Minimum CAISO real-time pricing for October–December

Similar to the simulation for the day-ahead market, the CAISO real-time market data were then modeled with a beta distribution and matched to the simulated results of the load study, generation profile, and day-ahead market for each jurisdictional scenario. Excess energy would be sold into the market, while energy to cover shortfalls would be purchased in the market. The results of the real-time market simulation are displayed in Tables 35 through 37 for the AWG Jurisdictions scenario for each renewable energy content scenario.

Table 35 Modeled Results of the CAISO Real-Time Market for the AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$1,946,708	$4,465,631	$5,519,074	$7,218,193
2021	$1,570,991	$4,639,809	$5,833,427	$7,694,858
2022	$1,931,037	$4,789,751	$5,885,413	$7,560,212
2023	$1,529,721	$4,582,325	$5,731,088	$7,547,689
2024	$1,483,856	$4,536,212	$5,664,029	$7,248,727
2025	$1,200,711	$4,576,051	$5,818,923	$7,595,633
2026	$1,191,607	$4,363,954	$5,626,635	$7,623,918
2027	$518,966	$4,472,635	$5,958,626	$7,886,697
2028	$1,189,862	$4,459,335	$5,762,831	$7,899,643
2029	$(382,624)	$4,474,185	$6,097,882	$8,291,407
2030	$153,369	$4,269,070	$5,851,634	$8,330,036

Table 36 Modeled Results of the CAISO Real-Time Market for the AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$1,372,662	$4,531,503	$5,668,861	$7,300,925
2021	$1,794,008	$4,339,055	$5,345,361	$6,930,608
2022	$1,042,492	$4,392,629	$5,694,008	$7,764,642
2023	$1,042,095	$4,406,967	$5,662,013	$6,998,765
2024	$1,755,234	$4,498,293	$5,661,391	$7,484,012
2025	$1,567,532	$4,736,897	$5,904,916	$7,110,961
2026	$1,188,542	$4,579,974	$5,984,966	$7,924,622
2027	$1,247,886	$4,547,115	$5,789,083	$7,897,222
2028	$388,733	$4,697,772	$6,238,115	$8,429,366
2029	$1,305,304	$4,727,795	$6,012,475	$7,804,494
2030	$360,593	$3,996,785	$5,378,705	$7,393,205

Table 37 Modeled Results of the CAISO Real-Time Market for the AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$2,184,996	$4,542,512	$5,671,180	$7,822,006
2021	$1,079,359	$4,326,768	$5,466,267	$7,218,885
2022	$1,554,044	$4,658,729	$5,817,401	$7,350,914
2023	$1,613,079	$4,565,592	$5,737,107	$7,338,207
2024	$1,917,657	$4,531,725	$5,609,108	$7,220,158
2025	$1,692,739	$4,415,943	$5,624,641	$7,630,049
2026	$1,800,739	$4,398,157	$5,475,425	$7,298,104
2027	$1,364,729	$4,616,540	$5,994,354	$8,160,622
2028	$595,519	$4,107,459	$5,516,752	$8,179,180
2029	$1,542,503	$4,832,271	$6,285,006	$8,561,025
2030	$695,508	$4,622,372	$6,128,897	$8,385,129

B.4.d Power Purchase Portfolio Cost

The AWG Jurisdictions participation scenario annual power procurement costs for the 2020-2030 Study period is summarized in this section for each of the renewable energy content scenarios. The figures presented here represent the base level of renewable energy content. The cost for customers to opt-up to 100% renewable electricity supply is based on replacing natural gas generation with renewable generation, and is included in the operational cost and pro forma analysis (see II.C.4.b Power Procurement Costs). For each renewable energy content scenario, the "Simulated Year MWh" increases annually while the "Net Simulated Year MWh" (or total CCA energy sales) decreases annually due to the effect of increasing levels of customer-owned distributed generation.

AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Table 38 reflects the high end of the 95% confidence interval power procurement costs based on the supply portfolio costs detailed in Section II.B.2 from 10 Monte Carlo simulation model sensitivity analysis iterations for the RPS Equivalent scenario. For the RPS Equivalent scenario, the renewable energy content increases each year. However, the associated cost increase from renewable energy content is mitigated by the anticipated decrease in natural gas generation costs, thus providing a relatively steady all-in procurement cost ($ per MWh) across the Study period.

Table 38 95% Confidence Interval Procurement Costs for the AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Year	RPS (%)	Net Simulated Year GWh	Simulated Year GWh	Resource Adequacy ($000)	Natural Gas PPA ($000)	Renewable PPA ($000)	CAISO Day-Ahead ($000)	CAISO Real-Time ($000)	Storage ($000)	Total ($000)	$ per MWh
2020	33	6,533	6,698	$54,008	$180,837	$196,690	$1,009	$5,519	$1,409	$439,473	$67
2021	35	6,533	6,736	$54,467	$169,815	$199,942	$1,242	$5,833	$1,312	$432,611	$66
2022	36	6,533	6,777	$54,822	$164,343	$204,353	$1,065	$5,885	$1,218	$431,687	$66
2023	38	6,524	6,812	$55,149	$150,287	$219,566	$879	$5,731	$1,131	$432,744	$66
2024	40	6,534	6,869	$55,456	$143,560	$225,438	$1,159	$5,664	$1,050	$432,327	$66
2025	42	6,506	6,888	$55,780	$136,655	$231,216	$1,034	$5,819	$974	$431,480	$66
2026	43	6,499	6,931	$56,110	$125,633	$243,667	$1,108	$5,627	$905	$433,049	$67
2027	45	6,488	6,972	$56,439	$120,514	$253,212	$1,154	$5,959	$840	$438,117	$68
2028	47	6,488	7,026	$56,767	$116,822	$262,435	$1,190	$5,763	$779	$443,756	$68
2029	48	6,455	7,047	$57,094	$106,313	$265,720	$1,282	$6,098	$724	$437,230	$68
2030	50	6,435	7,085	$57,421	$100,887	$273,889	$1,046	$5,852	$672	$439,767	$68

Table 39 shows the Monte Carlo simulated range of total portfolio pricing for the RPS equivalent scenario.

Table 39 Sensitivity Analysis for the Cost of Power ($ per MWh) for the AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Year	Minimum	Average	95%CI	Maximum
2020	$52	$63	$67	$73
2021	$52	$62	$66	$73
2022	$51	$62	$66	$72
2023	$51	$62	$66	$72
2024	$51	$62	$66	$73
2025	$52	$62	$66	$72
2026	$52	$62	$67	$73
2027	$52	$63	$67	$75
2028	$53	$64	$68	$74
2029	$54	$64	$68	$73
2030	$55	$65	$68	$74

AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario

Table 40 reflects the high end of the 95% confidence interval power procurement costs from 10 Monte Carlo simulation model sensitivity analysis iterations for the Middle of the Road (50%) renewable energy content portfolio. The overall decrease in price across the Study period is largely due to the projected decrease in both natural gas and renewable generation costs.

Table 40 95% Confidence Interval Procurement Costs for the AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario

Year	Net Simulated Year GWh	Simulated Year GWh	Resource Adequacy ($000)	Natural Gas PPA ($000)	Renewable PPA ($000)	CAISO Day-Ahead ($000)	CAISO Real-Time ($000)	Storage ($000)	Total ($000)	$ per MWh
2020	6,528	6,692	$53,952	$133,547	$288,189	$1,321	$5,669	$1,408	$484,086	$74
2021	6,518	6,722	$54,376	$131,324	$290,232	$1,037	$5,345	$1,309	$483,623	$74
2022	6,521	6,765	$54,722	$128,828	$288,051	$1,318	$5,694	$1,216	$479,830	$74
2023	6,514	6,802	$55,045	$120,995	$284,263	$1,153	$5,662	$1,129	$468,248	$72
2024	6,524	6,857	$55,347	$123,200	$284,444	$1,371	$5,661	$1,048	$471,071	$72
2025	6,491	6,873	$55,666	$113,728	$281,525	$1,220	$5,905	$972	$459,016	$71
2026	6,481	6,913	$55,979	$110,366	$277,000	$1,201	$5,985	$902	$451,434	$70
2027	6,470	6,953	$56,299	$111,851	$278,949	$1,287	$5,789	$838	$455,013	$70
2028	6,471	7,009	$56,618	$103,680	$275,119	$1,352	$6,238	$777	$443,785	$69
2029	6,434	7,027	$56,937	$102,962	$276,311	$1,043	$6,012	$722	$443,987	$69
2030	6,418	7,067	$57,255	$99,426	$276,176	$1,373	$5,379	$670	$440,279	$69

Table 41 shows the Monte Carlo simulated range of total portfolio pricing for the AWG Jurisdictions Middle of the Road (50%) renewable energy content scenario.

Table 41 Sensitivity Analysis for the Cost of Power ($ per MWh) for the AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$58	$69	$74	$81
2021	$56	$69	$74	$82
2022	$56	$69	$73	$81
2023	$55	$67	$72	$79
2024	$57	$68	$72	$80
2025	$55	$66	$71	$78
2026	$54	$65	$70	$76
2027	$56	$66	$70	$77
2028	$53	$64	$68	$75
2029	$53	$65	$69	$75
2030	$56	$65	$69	$75

AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario

Table 42 reflects the high end of the 95% confidence interval power procurement costs from 10 Monte Carlo simulation model sensitivity analysis iterations for the AWG Jurisdictions Aggressive (75%) renewable energy content portfolio. Again, the overall decrease in price across the Study period is due to the projected decrease in both natural gas and renewable generation costs.

Table 42 95% Confidence Interval Procurement Costs for the AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario

Year	Net Simulated Year GWh	Simulated Year GWh	Resource Adequacy ($000)	Natural Gas PPA ($000)	Renewable PPA ($000)	CAISO Day-Ahead ($000)	CAISO Real-Time ($000)	Storage ($000)	Total ($000)	$ per MWh
2020	6,524	6,690	$53,952	$68,990	$439,033	$1,794	$5,671	$1,408	$570,848	$87
2021	6,521	6,725	$54,376	$63,657	$430,947	$1,352	$5,466	$1,309	$557,107	$85
2022	6,518	6,763	$54,722	$63,050	$429,223	$1,256	$5,817	$1,216	$555,286	$85
2023	6,511	6,799	$55,045	$59,946	$429,051	$1,639	$5,737	$1,129	$552,547	$85
2024	6,520	6,856	$55,347	$59,777	$425,690	$1,451	$5,609	$1,048	$548,922	$84
2025	6,494	6,875	$55,666	$57,030	$424,154	$1,465	$5,625	$972	$544,911	$84
2026	6,484	6,913	$55,979	$57,491	$426,086	$1,405	$5,475	$902	$547,340	$84
2027	6,470	6,954	$56,299	$54,474	$423,063	$1,429	$5,994	$838	$542,097	$84
2028	6,470	7,007	$56,618	$54,421	$420,235	$1,512	$5,517	$777	$539,081	$83
2029	6,435	7,027	$56,937	$52,290	$410,353	$1,505	$6,285	$722	$528,091	$82
2030	6,414	7,065	$57,255	$49,684	$405,808	$1,369	$6,129	$670	$520,916	$81

Table 43 shows the Monte Carlo simulated range of total portfolio pricing for the AWG Jurisdictions Aggressive (75%) renewable energy content scenario.

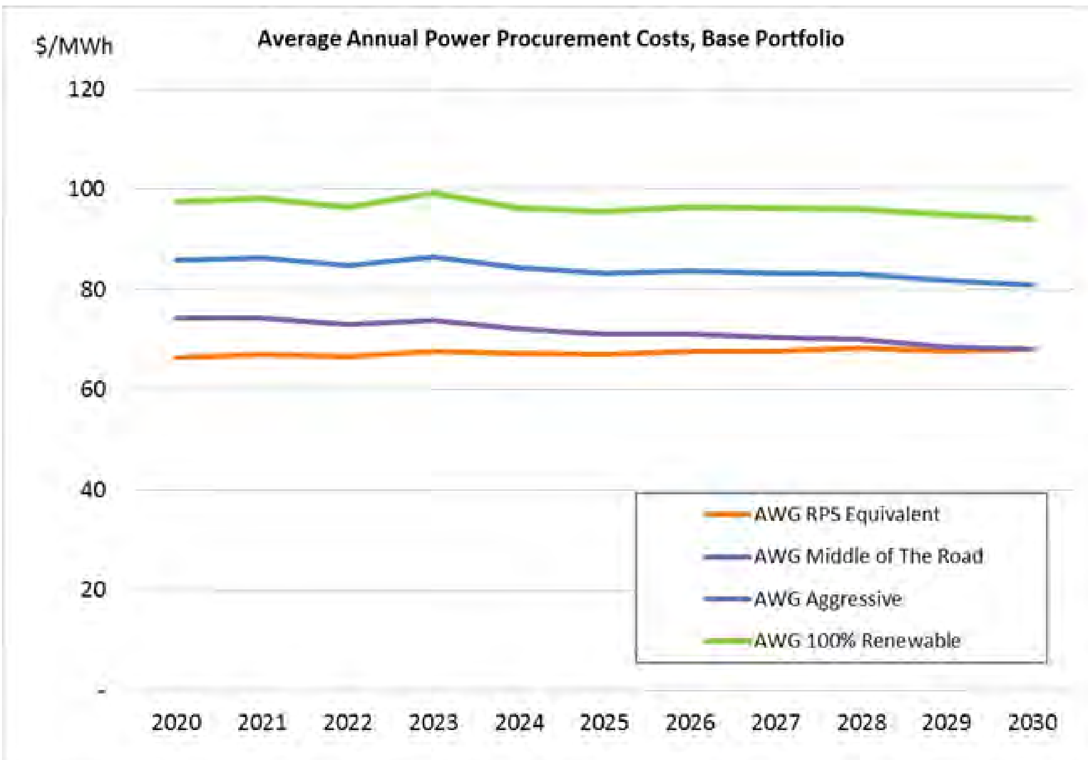
Table 43 Sensitivity Analysis for the Cost of Power ($ per MWh) for the AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario

Year	Minimum	Average	95% CI	Maximum
2020	$68	$82	$87	$97
2021	$64	$79	$85	$95
2022	$64	$79	$85	$95
2023	$65	$80	$85	$93
2024	$64	$79	$84	$92
2025	$66	$79	$84	$92
2026	$69	$80	$84	$91
2027	$68	$79	$84	$93
2028	$67	$79	$83	$90
2029	$67	$78	$82	$88
2030	$67	$77	$81	$87

B.4.e Cost of Power Summary

The cost of power is the underlying driver behind CCA financial and operational performance and the resulting rates paid by CCA customers. The analysis contained here shows the higher costs associated with greater percentages of renewable energy content within a supply portfolio. The simulation included projecting the cost of renewable energy, natural gas, and storage, and incorporated CAISO market purchases to balance electricity supply and demand. In addition to the base cost of power, the additional cost of power for 2% of customers to opt-up to 100% renewable was considered and included in the operational cost analysis and pro forma analysis (see Section II.C.4.b Power Procurement Costs).Figure 43 compares the price of each renewable energy content scenario for the AWG Jurisdictions scenario, for the baseload portion and for the opt-up portion (100% renewables).

Figure 43 Comparison of Forecasts for Annual Cost of Power



B.5. Power Procurement Risks

The power procurement plan and costs projections are built upon forecasts of multiple variables. The Monte Carlo simulation strategy models an approach to power procurement and includes the effects of variability in each load and power procurement variable; however, unique risks are associated with a supply portfolio with a 50% or greater percentage of renewable generation. The risks discussed here must be weighed against the CCA's economic, environmental, and local control goals.

The power procurement cost estimates in Section II.B rely on the assumption that current economics for natural gas and bulk scale renewable generation apply to both 50% and 75% renewable generation portfolios. However, this assumption, while useful for cost comparison and illustration, is unlikely to hold in a real-world application. Unfortunately, estimating the alternative generation cost economics of a future with 50% or more renewable generation would require a separate study. For example, the variability of renewable output and associated price volatility in CAISO markets could be greater than that modeled in the Monte Carlo simulation for this Study because the model relied on historical data. Additionally, the risk-adjusted cost of contracting an ESP to provide the supply portfolio, could increase to account for both CCA price certainty and mitigating the renewable generation intermittency and associated CAISO price volatility.

The cost of a supply portfolio with large-scale renewable generation, would be impacted by the intermittency of solar power generation, the associated volatility in CAISO pricing due to renewable generation variability, the capital/infrastructure associated with increasing renewable generation, and renewable energy PPAs. Infrastructure costs are not limited to the construction of renewable generation but also extend to transmission and distribution and infrastructure investments required to support renewables as discussed in Appendix B. Transmission and distribution infrastructure costs associated with renewable generation interconnection to the grid would accrue to the IOU delivery side of the bill, and therefore would have an effect on the overall cost for electricity for all customers.

B.5.a Cost of Renewable PPAs

The energy supply portfolio cost used in this Study assumes that the cost of energy forecasts still apply with increasing levels of renewable generation, including customer-owned solar generation (Section II.A.5.a) and bulk scale renewable generation. In fact, these assumptions are altered by the intermittency of renewable generation resources and the variability of solar generation output during daylight hours. The rigidity in timing of generation is another major uncertainty.

As described in Power Purchase Agreements Section II.B.2.a, "a 'full requirements' contract structure could be created, where a third party performs all the operations necessary to deliver the minute-to-minute shaped energy, including all required market components to Central Coast Power CCA's delivery point at a fixed price." Taking all of the risk factors described in this section into account, PPAs with requirements for renewable generation to comprise 50% or more of the portfolio would contain price premiums for the financial risk transfer from the CCA to the ESP. Full requirements contracts are more expensive than a supply portfolio approach, regardless of the renewable or conventional generation content, because the supplier carries all price, volumetric, and operational risk while the purchaser receives price stability. Essentially the risk is transferred to the PPA counterparty and a larger renewable power supply content includes higher uncertainty due to output intermittency and variability.

The price premium for higher renewable content requirements cannot be known without a procurement process to validate the power purchase costs estimates in Section II.B. The Advisory Working Group should proceed with a Request for Information to solicit pricing from potential ESPs for power procurement (power supply portfolio plus CAISO schedule coordination) as well as back-office customer service functions prior to filing a CCA implementation plan with the CPUC. The responses would provide the basis for either validating the cost assumptions in this Study or providing a foundation for updating the assumed costs based on the Request for Information responses.

B.5.b Renewable Generation Effect on Conventional Generation

Dispatching natural gas generation facilities to produce power only when the sun is down and adjust output to compensate for renewable generation variability will fundamentally change the business economics for natural gas independent power producers. With the same fixed costs for operations and the new requirement to essentially backfill solar shortfall to provide morning and evening generation, the generator's utilization capacity factor as well as generating efficiency (heat rate) decreases significantly. Efficiency for natural gas plants during ramp up and ramp down is much lower than it is during steady-state operation, so fuel use per MWh generated would increase during these ramp periods. As a result, generators would likely need to charge more per MW and MWh sold. This economic consideration for a supply portfolio requires significant research beyond the scope of this Study and is therefore articulated as a risk for the CCA.

B.5.c CAISO Pricing

A major driver for CAISO price spikes is when renewable generation, either customer-owned DER or bulk scale supply, does not perform as expected. When customer-owned DER produces less than expected, the CAISO will call upon higher-priced reserve generation resources to meet the customer load obligation of the CCA. Simultaneously, bulk scale solar may also be underperforming relative to expectations for the same reason that customer-owned DER is generating less than expected. This results in a simultaneous shortfall of supply coincident with increased demand. The result can be CAISO price spikes of $1,000 per MWh or more.

The inverse is also true. When customer-owned DER produces more than expected, overall customer demand serviced by the CCA is less than expected, and overproduction of bulk scale solar, this excess generation relative to overall demand results in negative CAISO pricing. Negative pricing incentivizes consumption (getting paid to consume more electricity) and compensates generators to stop producing electricity.

With increasing renewable generation, CAISO will need to dynamically adjust resources for both the variable output of renewable generation and the shoulder periods, including providing fast response "ramping" resources to come online as the sun sets and solar generation output diminishes. CAISO continues to proactively create market products such as the Flexible Ramping Product,[120] energy storage and distributed energy efficiency,[121] and demand response[122] to address the increasingly dynamic task of matching electricity supply and demand in real time. However, the economic implications in future CAISO markets with increasing magnitude and variability of renewable generation is uncertain.

The CAISO now tracks the amount of statewide renewable resources that contribute to the total electricity needs for participating LSEs, including CCAs, in California,[123] with the exception of customer-owned DER (which have the effect of reducing demand).

The variability of renewable generation impacts both the construct of the CCA supply portfolio and the CAISO generation mix. The increasing volatility of the CAISO market prices illustrated earlier could require more complex CAISO market products. The implication for CCA portfolio management would be to economically hedge CCA load variability, taking into consideration the increased volatility of the spot/short-term markets. Higher spot volatility may imply higher hedge percentages (i.e., fixed price products, even for short-term requirements) to mitigate/lower exposure to the CAISO market prices.

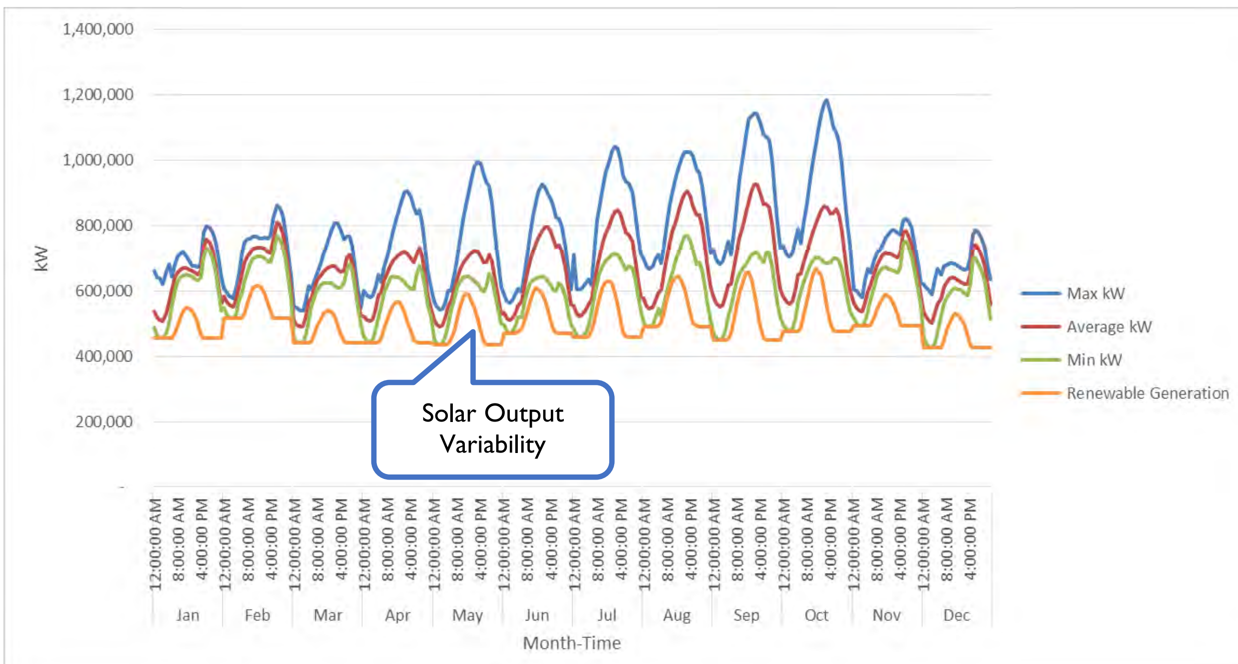
Most simply, with the increasing amount of concurrent generation from solar, the real-time value of that electricity in the market may be significantly less than originally forecasted.

B.5.d Intermittency of Renewable Generation

With the exception of geothermal generation, renewable generation has been an intermittent and variable source for bulk scale generation. However, wind generation in California now has enough geographical diversity to deliver relatively predictable generation supply during a 24-hour period. Still, the expected amount of renewable generation can vary from day to day and hour to hour. Figures 44 and 45 illustrate this intermittency.

Figure 44 is a graphical depiction of the maximum, minimum, and average hourly demand for each hour of each month. The orange line is a bulk renewable generation output curve that assumes geothermal and wind generation can provide "base" generation meeting the minimum monthly need on a consistent basis.[124] The area under the orange curve is equivalent to a 75% renewable supply portfolio, where natural gas generation would provide the 25% portion of the generation portfolio needed during the "shoulder period" after the sun sets and when demand exceeds the solar output.

Figure 44 Simplistic Depiction of Demand vs. a 75% Renewable Generation Portfolio Output—6% Bulk Solar, 69% from Wind and Geothermal



In Figure 45 the renewable portfolio is comprised of half solar (providing 37.5% of the total generation requirement) and half geothermal/wind, (providing 37.5% of total the generation requirement). In this depiction, solar overproduces when the sun is up and the excess energy would be sold to CAISO and/or transferred to energy storage for later use. The remaining 25% of total generation requirement during "shoulder periods" could be met by natural gas generation, energy storage and/or CAISO. This illustration aligns with selling excess solar energy to CAISO at a low price during overproduction periods and utilizing CAISO resources during shoulder periods.

Figure 45 Simplistic Depiction of Demand vs. a 75% Renewable Generation Portfolio Output—37.5% Bulk Solar, 37.5% Wind and Geothermal

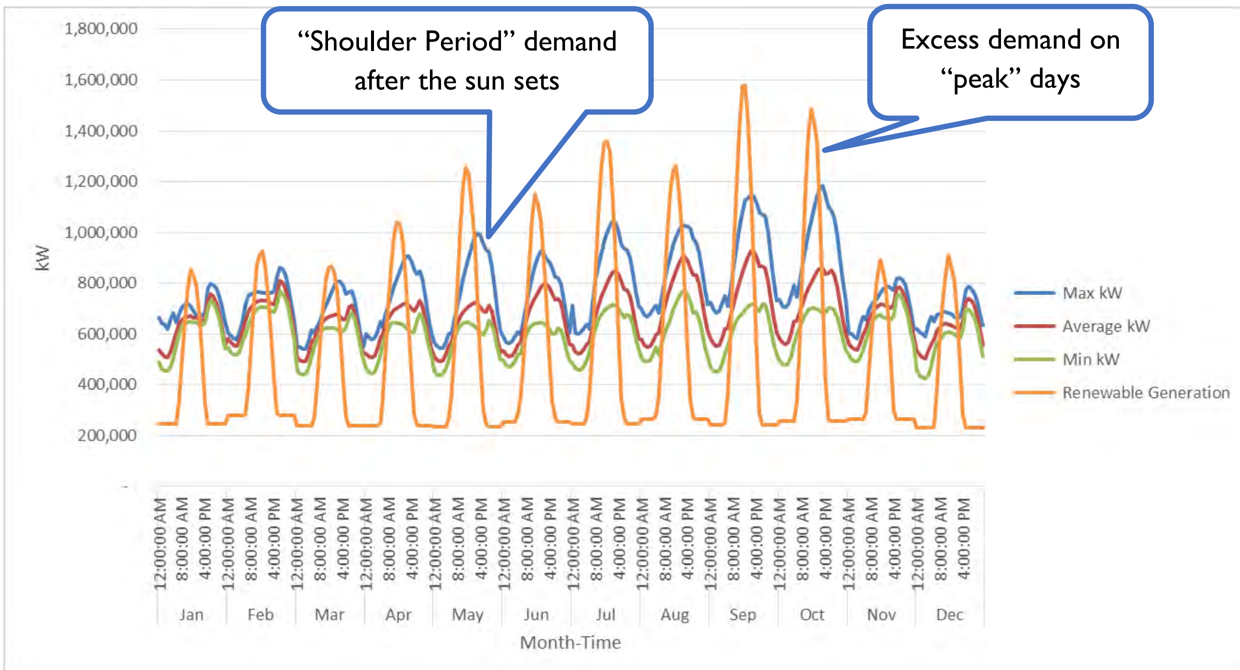


Figure 44 and Figure 45 are simplified to be illustrative. For example, the renewable generation orange curve is depicted as smooth and predictable when in fact it is variable and that the demand curves look smooth while the variation for any given hour of any given day can be somewhere between the maximum and minimum demand curves.

The power supply cost estimates in Section II.B assume that CAISO market pricing would be relatively constant. Indeed, the average CAISO price has remained around $40 per MWh for many years. However, price volatility—the frequency and magnitude of price spikes and negative pricing—has increased. For example, Table 44 is a simple interpretation of the additional cost incurred in the solar overproduction scenario. In this example, with CAISO pricing around $40 per MWh and renewable generation cost approximately $80 per MWh, the excess solar generation would be sold at a depressed CAISO overproduction price of $20 per MWh loss and the shoulder period energy would be procured from CAISO for $60 per MWh.

Table 44 Simplistic Cost Estimate for Solar Overproduction Depicted in Figure 45

#	Cost and Transaction	Amount and Cost
A	Annual Solar Overproduction (MWh)	21,275
B	Renewable Generation Cost ($ per MWh)	$80
C	Cost of Annual Solar Overproduction ($) (A x B)	$1,702,022
D	CAISO Average Market Price ($ per MWh)	$40
E	Illustrative CAISO price during solar overproduction ($ per MWh)	$20
F	Illustrative CAISO price during solar underproduction ($ per MWh)	$100
G	CAISO Proceeds from Solar Overproduction Sale ($) (A x E)	$425,505
H	Procurement of shoulder period energy from CAISO ($) (A x F)	$2,127,500
	Net Annual Loss from Solar Over Procurement Scenario ($) (C+G+H)	**$4,255,027**

B.5.a Siting and Construction Cost Concerns of Renewable Generation

The cost of the underlying technology for renewable generation has become commoditized. As a result, the cost of the renewable technology is less of a cost driver than the labor and land required to build the renewable generation resources.

According to the NREL "Land-Use Requirements for Solar Power Plants in the US" white paper, 7.9 acres of land are needed for 1 MW of large solar PV generation.[125] With an average annual hourly (bundled customer) demand of 728 MW, the AWG Jurisdictions scenario would require 2,875 acres of land to meet 50% of the average demand with solar PV. This is less than one percent (<1%) of the total land in the Tri-County Region.

According to the US DOE, an average of 85.24 acres of land is needed per MW for wind energy. [126] This is over ten times the amount of land needed to generate 1 MW with solar PV.

The cost of land is assumed to be included in the renewable PPA cost. However, as California LSEs strive to meet RPS goals, additional construction will be required and the prime sites for wind and solar generation will likely increase in value. As a high-level simple example, a quick search in Santa Barbara County shows parcels of land over 500 acres are currently available for $2,000–$60,000 an acre. Procuring enough regional land parcels to build solar PV to meet 50% of average demand (~364 MW) could cost $172.5 million. However, this high-estimate example may not reflect actual land use costs as the CCA may consider smaller scale projects on government-owned land, parking lots, and in rural areas.

Another construction cost comes from delivery of the renewable energy to customers. Once bulk scale renewable generation resources are built, transmission lines are needed to deliver the electricity to consumers. In the case of a CCA, the IOU would permit and build the transmission lines in partnership with the CCA. However, as the SCE Tehachapi Transmission project illustrated, transmission projects take a long time and are costly. It took twelve years (2004–2016) to permit and build transmission facilities equaling 250 miles (spanning an area of approximately 173 miles) that will deliver electricity from 4,500 megawatts of renewable wind and other energy generators in Kern County at an estimated cost of $2.1 billion.[127,128] As another example, SDG&E is currently pursuing the Sunrise Powerlink,[129] a 117-mile 500-kilovolt transmission line estimated at $1.883 billion[130] that will carry renewable energy from the Imperial Valley to San Diego.

If Central Coast Power CCA pursues bulk scale renewable generation, a transmission level interconnection process will need to be pursued.[131] While the cost of transmission would be recovered by the IOU assuming CPUC approval, appropriate permitting, and right of way from any municipalities impacted, the overall cost to customers on the delivery charge side of their bill would increase accordingly. Therefore, overall cost impact to customers should be taken into account. Moreover, customers' appetite for utilizing more land for electricity purposes may wane.

B.5.b Existing IOU Generation

The years-long drought that covered much of the Tri-County Region and California as a whole was interrupted this winter as rain and snow covered much of the region. The output of hydroelectric generation during the drought gradually faded as reservoirs dried up. With the reservoirs filling, hydroelectric generation is expected to return to roughly pre-drought generation levels. In 2011, 18% of PG&E's electricity was generated by large hydroelectric, while SCE came in at 7%.[132] Table 3 on page I-11 depicts the 2015 SCE and PG&E power content labels showing hydroelectric production at 6% and 2%, respectively.

IOU rates could decrease given the likelihood of existing hydroelectric facilities providing a larger portion of IOU energy supplies. Additionally, while the large hydroelectric facilities do not contribute toward IOU RPS compliance, the facilities do not emit GHG emissions.

Another heritage IOU generation source is also in transition. SCE has already shut down the San Onofre Nuclear Power Station and PG&E has submitted an application to shut down Diablo Canyon Nuclear Power Plant in 2025.[133] Diablo Canyon is the last "conventional" base load plant in the state and its generation may be replaced with natural gas generation for some portion of the Study planning horizon. The variability of renewable generation is causing a re-evaluation of "base" generation, which used to correspond to the minimum demand threshold for an LSE. As already encountered in Hawaii, the daytime minimum load can now be less than the nighttime load after significant adoption of customer-owned PV.[134]

All three IOUs pursued smaller utility scale solar projects (> 1 MW) on warehouses and other large building rooftops. This type of Solar Rooftop program started in 2008.[135] While some progress was made, the customer enrollment was less than expected leading to program termination.[136] Reasons for low customer participation included the fact that some large building rooftops are not structurally suitable for large solar arrays; and often times a building owner is a different entity than the building occupant which requires both the landlord and tenant to agree on program participation.

B.5.c Procurement Risks Summary

Power procurement is fundamentally a speculative exercise consisting of forecasting customer and market behaviors and managing risks. This is true for both traditional power procurement and when developing a supply portfolio consisting of a high renewable energy content. Because of market factors and trends within the industry as a whole, tremendous uncertainty exists regarding future power procurement economics. Simply, there is very little experience across the international community in managing supply portfolios consisting predominantly of renewable, non-dispatchable resources. This is especially true when considering the transition of entire markets to a greater percentage of non-dispatchable resources. While the early adopters of renewable energy could rely on a fairly steady wholesale market price to assist in balancing the fluctuations in solar/wind generation, today's CAISO market is already proving volatile as more renewables are incorporated.

C. Operational Cost Analysis

The cost of service analysis relied on traditional utility ratemaking principles and followed an industry standard methodology for creation of a financial pro forma to forecast the future economic and financial performance of the CCA program. The first step in the cost of service analysis was developing the projected CCA program revenue requirement, the amount of money to be collected from customers required to cover the costs of the CCA program, including all operating and non-operating expenses, debt-service payments, a contingency allotment, a working capital reserve, and rate stabilization fund. The revenue requirement was based on a comprehensive accounting of all pertinent costs and projections of customer participation; assumptions and input development are described later in this report. Cost assumptions relied on historical publicly-available information, power cost forecasts conducted for this Study, data provided by PG&E and SCE, and subject matter expertise gained working with a host of public utilities and similar organizations.

C.1. Introduction to Operational Cost Analysis

To assess the financial feasibility of a CCA program, a Financial Pro Forma Cost of Service Analysis was conducted. This section describes the methodology and assumptions used in the analysis, as well as the financial pro forma model, its primary components, and functionality. The pro forma model measurements of CCA program financial feasibility and how these results inform Study recommendations and conclusions are discussed. The next section provides an explanation of the individual cost component assumptions used to establish the overall CCA program revenue requirement. Tabular and graphic depictions for various customer classes and cost components by scenario are examined. Next, the methodology used to translate CCA program revenue requirements into unitized requirements by customer class (CCA program rate proxies)[137] is presented. Model outputs were used to develop CCA program rate proxies based on the cost to serve the customers within each class. Appendix B includes additional information on cost of service and ratemaking principles.

C.2. Approach

The pro forma model was used to forecast revenues and expenses of the CCA program over the 2020 to 2030 Study period. The pro forma model is a customized, user-friendly, Microsoft Excel-based spreadsheet. Dynamic and comprehensive, the pro forma model performs scenario and sensitivity analyses through modification of input assumptions, quickly forecasting revenues by customer class, expenses, working capital requirements, and key financial metrics. This model was used to evaluate the impact of cost drivers on CCA program feasibility, develop a range of possible performance outcomes, and test the robustness of planning assumptions. Results tell the financial story of the CCA program from start up through the end of the Study period, 2030. The pro forma model illustrates the CCA program's relative financial health by year as measured against defined financial targets.

The analysis considers pertinent cost drivers and performance results impacting the long-term financial feasibility of the CCA program. Costs are the readily-monetized expenses and capital outlays required to get the CCA program up and running and provide reliable, ongoing service over the Study period. CCA program costs include power purchases, staff salaries and benefits, PG&E and SCE service fees/charges, facilities expenses, information technology costs, rate stabilization and reserve funding, and required debt service, among others. In determining financial feasibility, the pro forma model does not include other benefits, tangible or intangible, such as the value of reducing carbon emissions, community engagement in decision-making, the benefits of local control and accountability for generation choices, and local job creation, among others. These benefits are considered outside of the pro forma model within this Study, and may impact overall conclusions and recommendations. The Financial Pro Forma Cost of Service Analysis simply evaluates the financial performance of the CCA program, quantified primarily in terms of projected customer costs when compared to PG&E and SCE.

Financial feasibility is assessed in terms of the ability of the CCA program to realistically deliver competitive costs for customers while paying its substantial up-front and ongoing operating costs. In particular, the analysis assessed CCA program capital and cash-on-hand requirements. The impacts of debt service and reserves, changes in power prices, and customer participation were evaluated. These financial metrics were used to assess the CCA program's ability to remain financially solvent and serve customers over the short- and long-term.

The analysis relied on traditional utility ratemaking principles and followed an industry standard methodology for creation of the financial pro forma to forecast the future economic and financial performance of the CCA program. The first step in the cost of service analysis was developing the projected CCA program Revenue Requirement, the amount of revenues required to cover the costs of the CCA program, including all operating and non-operating expenses, debt-service payments, a contingency allotment, a working capital reserve, and rate stabilization fund. The Revenue Requirement was based on a comprehensive accounting of all pertinent costs and projections of customer participation; input development is described later in this section. Cost assumptions relied on historical publicly-available information, power cost forecasts conducted for this Study, data provided by PG&E and SCE, and subject matter expertise gained working with a host of public utilities and similar organizations.

To develop the Revenue Requirement, a Test Year was created using expected assumptions around key drivers and resulting performance for a typical year. The Test Year is designed to project the amount of revenues needed to cover anticipated costs based on a normalized year of operation. For this Study, the Test Year Revenue Requirement equals the average projected operating costs for the first three full years of operation. Table 45 summarizes the CCA program Test Year Revenue Requirement for the AWG Jurisdictions scenarios. Changes in the total Revenue Requirement between scenarios drive corresponding changes in customer rate proxies by class. The Revenue Requirement information provided in Table 45 is a high-level summation of detailed individual cost components of the pro forma model. Detailed pro forma results are included in Appendix D for the AWG Jurisdictions participation scenarios.

Table 45 Central Coast CCA Test Year Revenue Requirements for AWG Jurisdictions Participation Scenarios

Description	AWG Jurisdictions Participation Scenarios		
	RPS Equivalent	Middle of the Road	Aggressive
REVENUE REQUIREMENT			
Baseload			
Total Operating Expenses Excluding Power Costs	$ 10,146,683	$ 10,256,373	$ 10,482,215
Total Non-Operating Expenses	16,959,517	18,158,147	20,239,969
Power Costs	461,419,035	489,933,855	549,930,521
Contingency/Rate Stabilization Fund	$ 54,171,111	$ 57,535,423	$ 64,613,615
BASELOAD REVENUE REQUIREMENT	**$ 542,696,345**	**$ 575,883,798**	**$ 645,266,320**
Opt-up to 100% RPS			
Total Operating Expenses Excluding Power Costs	$ 207,075	$ 209,314	$ 213,923
Total Non-Operating Expenses	346,113	370,574	413,061
Power Costs	12,617,576	12,617,576	12,617,576
Contingency/Rate Stabilization Fund	$ 1,105,533	$ 1,174,192	$ 1,318,645
OPT-UP TO 100% RPS REVENUE REQUIREMENT	**$ 14,276,297**	**$ 14,371,657**	**$ 14,563,205**
TOTAL REVENUE REQUIREMENT	**$ 556,972,642**	**$ 590,255,454**	**$ 659,829,525**

The CCA program Revenue Requirement for the AWG Jurisdictions RPS Equivalent scenario is approximately $557 million, of which $543 million is allocated to baseload customers and $14 million to customers opting up to 100% renewable portfolio content.

C.3. Customer Assumptions

Customer CCA program participation was assumed to be constant across the renewable energy content scenarios for each participation scenario; for example, the customer participation (accounts and kWh consumed) for each rate class was held constant for all AWG Jurisdictions participation scenarios. For all 24 scenarios modeled, an opt-out rate of 15% was used for all rate classes for all years, meaning that 15% of bundled customers by load in each rate class were assumed to opt out of the CCA.[138] This 15% opt-out rate is in addition to existing DA customers who are expected to remain with their current ESP.

This Study explored CCA feasibility over an eleven-year timeframe, from 2020 to 2030, with the assumption that the CCA would become operational with customer enrollment in 2020 and 2021 including three enrollment periods as shown in Table 46.

Table 46 Assumed CCA Customer Enrollment Phase-in

Phase	Customer Classification	Assumed Enrollment Month
1	Agriculture, Large Commercial, and Very Large Commercial	May 2020
2	Medium and Small Commercial	November 2020
3	Outdoor Lighting, Residential, Residential CARE, and Traffic Control	May 2021

May enrollment is recommended for each phase because the March through May energy consumption is relatively constant. This relatively stable month to month consumption from March to May reduces the risk that a customer may perceive a bill increase or decrease to the CCA rather than normal seasonal changes in electricity consumption. Phasing in Large and Very Large Commercial customers first allows the CCA to serve more load and fewer customers during its early operations. Residential customers have lower individual loads and generally higher levels of customer support needs so they are phased in last in an effort to minimize operational challenges.

Figure 46 and Figure 47 summarize Test Year customer accounts by rate class and Test Year customer usage by rate class for the AWG Jurisdictions participation scenarios, respectively. Average CCA program Test Year customer profiles for the AWG Jurisdictions participation scenarios are provided in Table 47.

Figure 46 Test Year Customer Accounts for AWG Jurisdictions Participation Scenario

Figure 47 Test Year Customer Usage for AWG Jurisdictions Participation Scenario

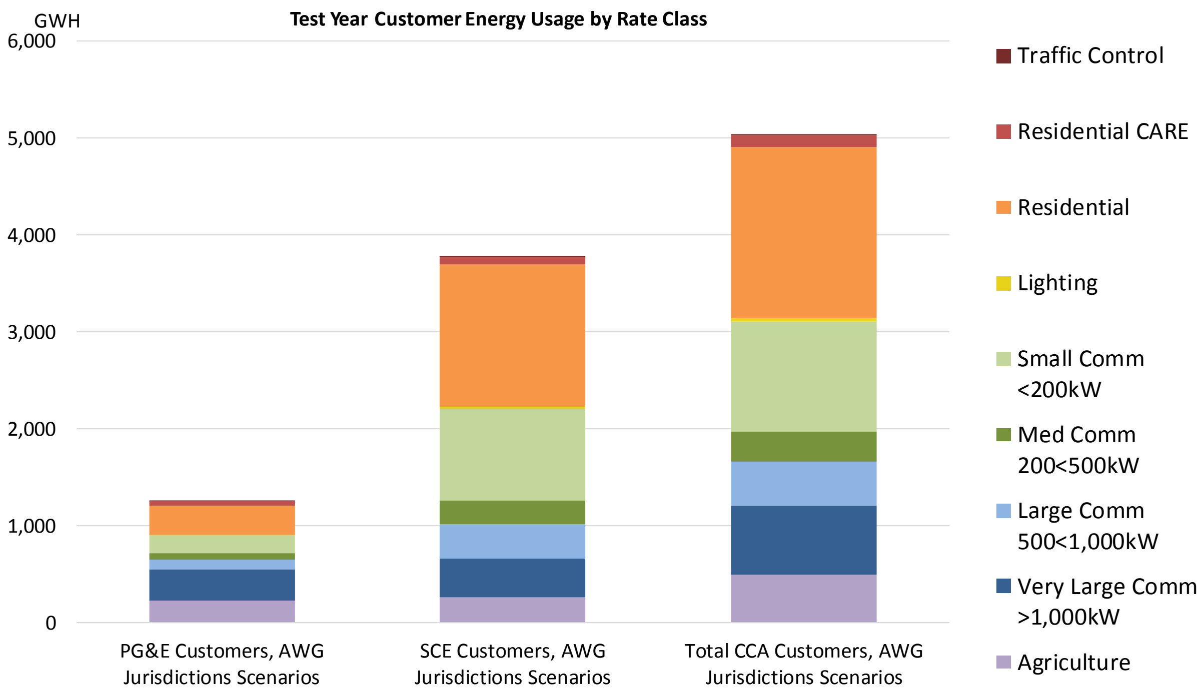


Table 47 Test Year Customer Accounts and Usage

Line	Description	Test Year Accounts	Test Year Annual Load (MWh)	Test Year Average Monthly Load (kWh/Account)
1	**BASELOAD**			
2	Agriculture	6,454	490,772	6,337
3	Very Large Comm >1,000kW	13	718,495	4,673,350
4	Large Comm 500<1,000kW	405	441,022	90,742
5	Med Comm 200<500kW	576	297,829	43,094
6	Small Comm <200kW	40,034	1,124,051	2,340
7	Lighting	1,757	26,357	1,250
8	Residential	256,812	1,709,325	555
9	Residential CARE	22,929	124,036	451
10	Traffic Control	841	2,811	278
11	**TOTAL BASELOAD**	**329,821**	**4,934,699**	**1,247**
12	**OPT-UP TO 100% RPS (MWH)**			
13	Agriculture	-	-	-
14	Very Large Comm >1,000kW	-	-	-
15	Large Comm 500<1,000kW	9	10,071	90,742
16	Med Comm 200<500kW	29	15,106	43,094
17	Small Comm <200kW	538	15,106	2,340
18	Lighting	-	-	-
19	Residential	9,078	60,425	555
20	Residential CARE	-	-	-
21	Traffic Control	-	-	-
22	**TOTAL OPT-UP TO 100% RPS**	**9,655**	**100,708**	**869**
23	**TOTAL CCA**	**339,476**	**5,035,407**	**1,236**
	CUSTOMERS OPTING UP TO 100% RENEWABLES		**Portion of Opt Up**	**Portion of Total CCA**
24	Agriculture		0%	0.00%
25	Very Large Comm >1,000kW		0%	0.00%
26	Large Comm 500<1,000kW		10%	0.20%
27	Med Comm 200<500kW		15%	0.30%
28	Small Comm <200kW		15%	0.30%
29	Lighting		0%	0.00%
30	Residential		60%	1.20%
31	Residential CARE		0%	0.00%
32	Traffic Control		0%	0.00%
33	**TOTAL**		**100%**	**2.00%**

C.4. Operating Costs

Operating costs consist of all costs directly associated with provision of the business services and activities of the CCA—namely procuring and providing power to customers. The pro forma model includes the following operating costs:

- Staffing Costs;
- Power Procurement;
- PG&E and SCE Service Charges;
- PG&E and SCE Cost Responsibility Surcharges (CRS);
- PG&E and SCE Franchise Charges;
- Energy Service Provider Charges;

- Other Startup Charges;
- Professional Services;
- Jurisdictional Administration;
- Other Operating Expenses; and
- Uncollectable Accounts.

C.4.a Staffing Costs

The analysis assumes the CCA will be an independent entity, and not an embedded department within a city or county government that will share staffing resources. Staffing cost assumptions were based on publicly available salary and benefit data for the City of Santa Barbara. In support of the Study, specific operating functions, duties, and resources required to operate the CCA were defined and required job positions developed. The resulting staffing projection was compared to similar City positions, in terms of skill sets and job functions, and other CCA information, to develop estimates of salary and benefit costs per position. Table 48 provides the staff positions and associated annual costs used in the pro forma model for the AWG Jurisdictions participation scenario. The CCA Test Year was assumed to have approximately 45 full time equivalent (FTE) staff at an approximate cost of $7 million per year. No staffing functions were assumed to be outsourced, with the exception of energy commodity market trading. Pro forma results are based on incrementally adding staff to support start up activities by phase, with approximately 35% of FTEs on board as of Phase I launch in May 2020. By Phase II all but 15% of FTE positions were assumed to be filled, with 38 FTEs on board as of 2021.

Table 48 CCA Test Year Staffing

Line	Description	Annual Salary and Benefit Costs	Full Time Equivalent Positions
	Executive Management Positions:		
1	General Manager	$ 350,868	1
2	Assistant General Manager	241,563	1
3	Chief Financial Officer	301,680	1
4	Customer Service Manager	241,563	1
5	Human Resources Manager	241,563	1
6	Attorney	$ 334,472	1
7	Total Executive Management Positions:	$ 1,711,709	6
	Other/Departmental Management Positions		
8	Accounting and Budget Manager	$ 163,957	1
9	Rates and Regulatory Affairs Manager	226,260	1
10	Customer Information and Billing Manager	226,260	1
11	Key Accounts Manager	226,260	1
12	DSM Program Manager	174,887	1
13	Communications and Public Relations Manager	174,887	1
14	Power Supply and Planning Manager	213,144	1
15	Information Technology Manager	226,260	1
16	Procurement and Contracts Manager	$ 163,957	1
17	Total Other/Departmental Management Positions	$ 1,795,873	9
	Analyst, Technical, Engineering Positions		
18	Contracts Analyst	$ 128,979	1
19	Accounting and Budget Analyst	257,959	2
20	Rates and Regulatory Affairs Analyst	128,979	1
21	Power Supply Analyst	277,633	2
22	DSM Analyst	$ 277,633	2
23	Total Analyst, Technical, Engineering Positions	$ 1,071,184	8
	Administrative, Customer Service, and Other Positions		
24	Executive Administrative Assistant	$ 341,030	3
25	Administrative Assistant	314,797	4
26	Customer Service Representative	314,797	4
27	Key Account Representative	994,671	7
28	Communications Specialist	122,421	1
29	IT Specialist	244,842	2
30	Human Resources Specialist	$ 142,096	1
31	Total Administrative, Customer Service, and Other Positions	$ 2,474,654	22
32	**Total, All Positions**	**$ 7,053,421**	**45**

Figure 48 presents a representative organization chart for the CCA.

Figure 48 CCA Organization Chart

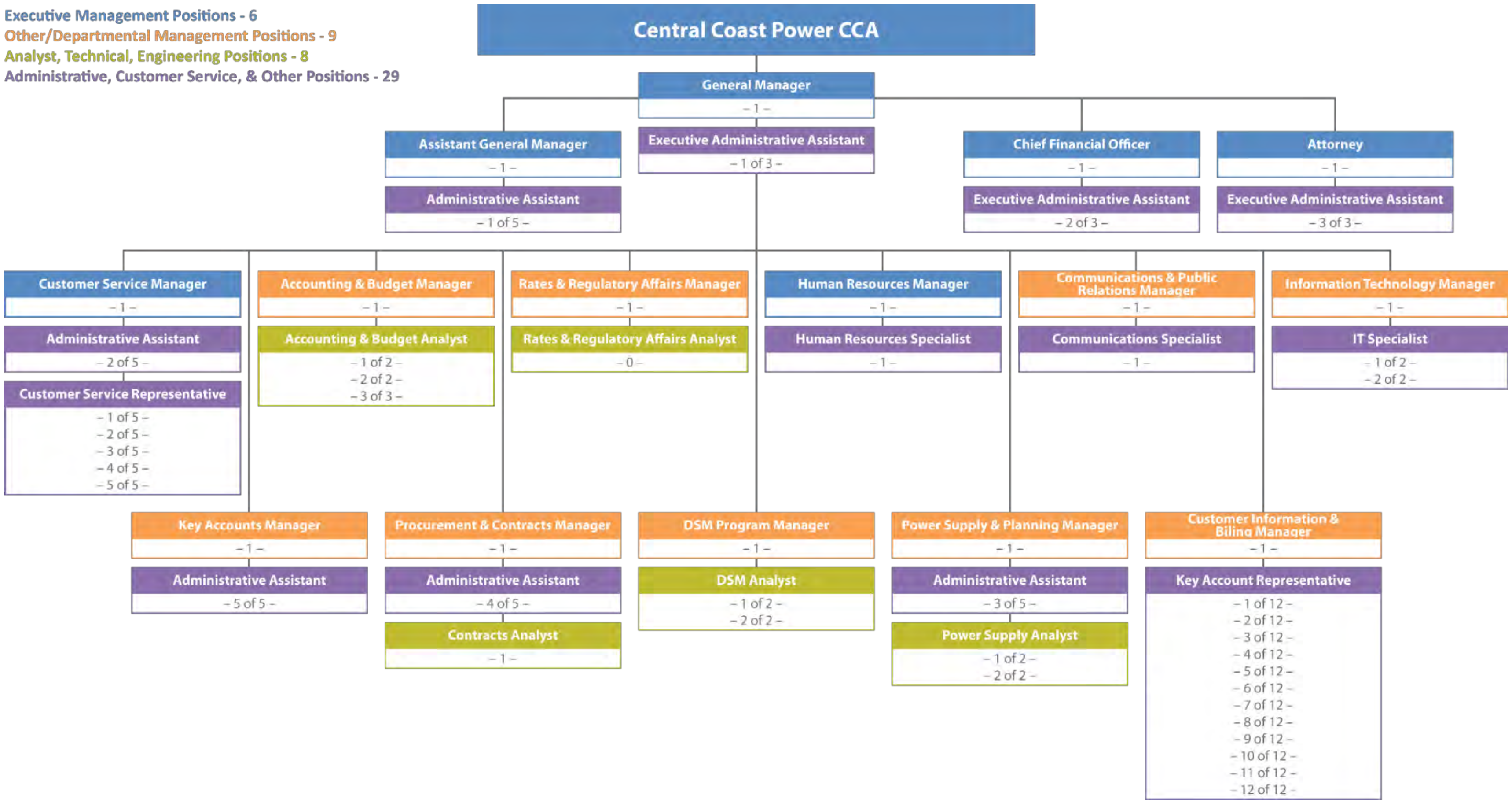


Figure 49 demonstrates the level of staffing assumed is reasonable when compared to other CCAs. This figure is based on the staffing assumptions for the AWG Jurisdictions scenarios.

Figure 49 CCA Staffing Comparison

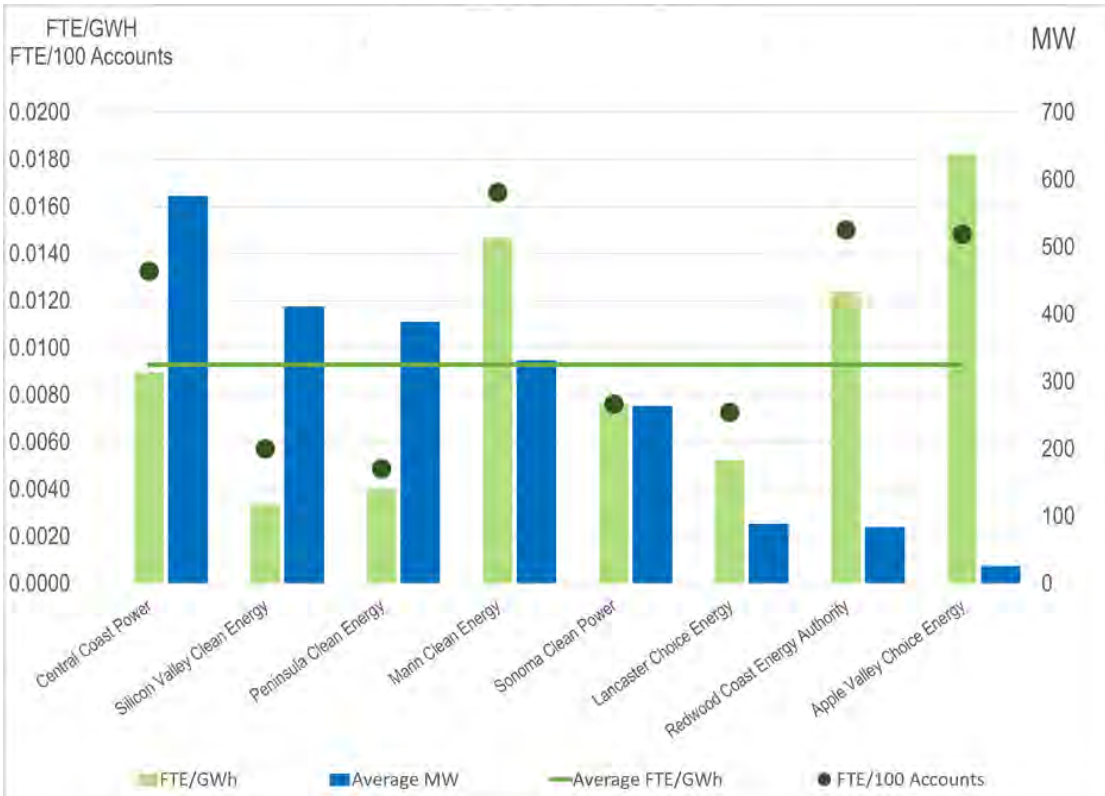
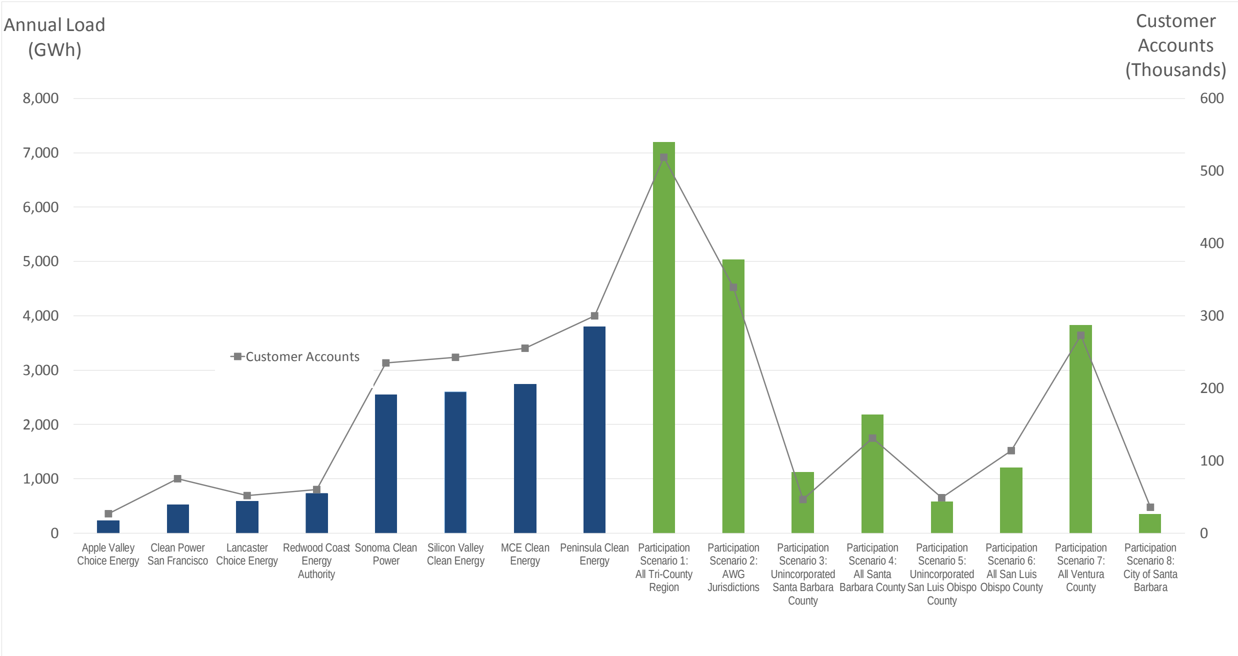


Figure 50 illustrates the size of the Central Coast Power CCA relative to other currently operating CCAs by Participation Scenario, illustrating the extreme range between scenarios assessed. Staffing assumptions are adjusted by scenario and range from a low of 24 for Participation Scenario 8: City of Santa Barbara and a high of 57 for Participation Scenario 1: All Tri-County Region.

Figure 50 Summary of CCA Size (GWh and Customer Accounts)



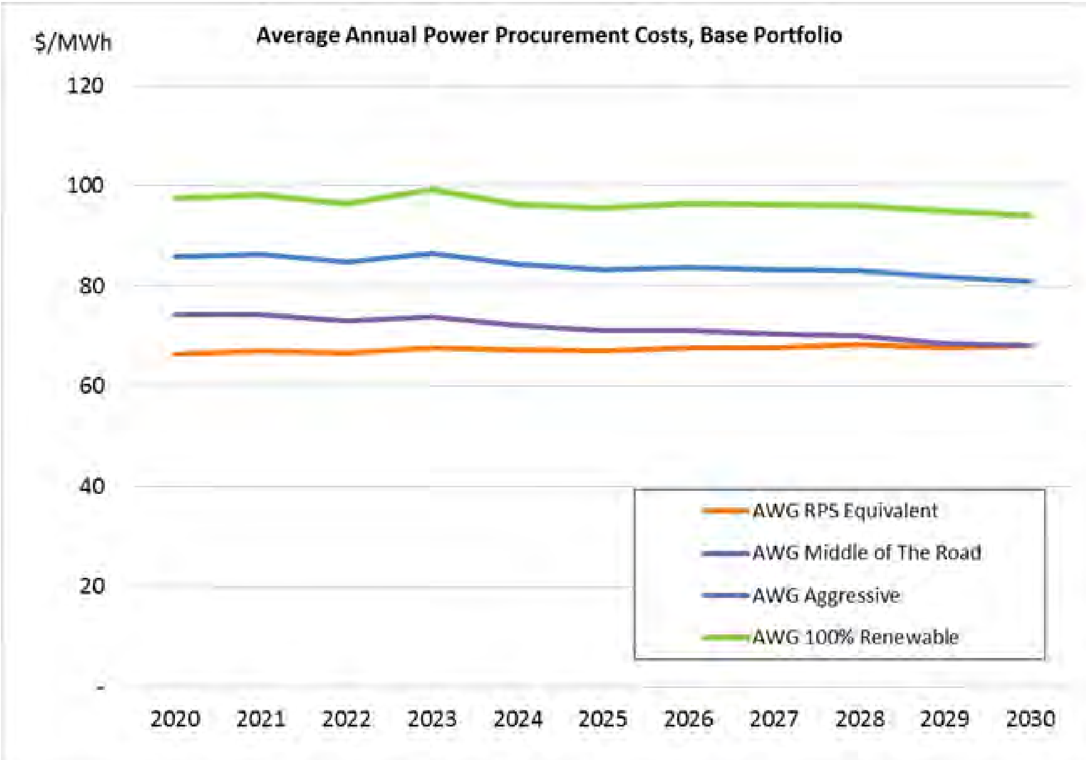
C.4.b Power Procurement Costs

As discussed previously, the various scenarios were developed to examine different participation and renewable energy content. Distinct forecasts of power procurement costs were developed for each of the 24 scenarios, on a normalized basis. This means that, on a dollar per MWh basis, the average monthly price of renewable energy and non-renewable energy secured through PPAs as well as CAISO day-ahead, real-time, storage, and resource adequacy purchases were kept the same between each participation and renewable energy content scenario. The total energy requirements served by each of these components changes depending on scenario, the price does not. This is what would be expected in actuality, as the amount of renewable energy procured by the CCA would have little to no bearing on the prevailing PPA and market prices on a long-term basis. Power procurement costs for the AWG Jurisdictions participation scenario by renewable energy scenario from 2020 to 2030 are shown in Table 49 and Figure 51 graphs these costs.

Table 49 Power Costs by Renewable Energy Content Scenario, AWG Jurisdictions Participation Scenario 2020-2030 ($ per MWh)

Scenario	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
AWG RPS Equivalent, Base Portfolio	66.49	67.05	66.70	67.72	67.31	67.06	67.69	67.78	68.24	67.75	68.02
AWG RPS Equivalent, 2% Opt Up Portfolio	97.53	98.11	96.41	99.30	96.33	95.52	96.43	96.13	96.01	94.86	94.07
AWG Middle of The Road, Base Portfolio	74.36	74.33	73.05	73.79	72.23	71.20	71.13	70.41	70.01	68.64	68.02
AWG Middle of The Road, 2% Opt Up Portfolio	97.53	98.11	96.41	99.30	96.33	95.52	96.43	96.13	96.01	94.86	94.07
AWG Aggressive, Base Portfolio	85.95	86.22	84.73	86.55	84.28	83.36	83.78	83.27	83.01	81.75	81.04
AWG Aggressive, 2% Opt Up Portfolio	97.53	98.11	96.41	99.30	96.33	95.52	96.43	96.13	96.01	94.86	94.07

Figure 51 Average Annual CCA Power Procurement Costs by Scenario 2020-2030 ($ per MWh)



C.4.c PG&E and SCE Service Charges

As part of the total cost of providing service for customers, the CCA will pay fees to PG&E and SCE for various services. Such services include those related to billing and customer notification processes. PG&E and SCE use an incremental costing methodology for these services, which include the following categories, among others:

- CCA Service Establishment;
- Opt Out Services;
- Electronic Data Interchange (EDI) Testing Services;
- Customer Notification, Initial & Follow-up (Optional Service);
- Customer Fees; and
- Mass Enrollment.

Costs for these CCA service fee charges are detailed in PG&E and SCE's publicly available rate schedules.

When a customer decides to purchase energy from a provider other than its IOU, such as a CCA program, the IOU charges an exit fee to recover costs associated with long-term power supply arrangements associated with serving the departing load. These "stranded costs" generally reflect the difference between the contract price for the energy or generation investments and the market price for which the excess energy can be sold. The price difference is recovered from the departed customers through the Power Charge Indifference Adjustment (PCIA) of the Cost Recovery Surcharge. The PCIA is either a charge or credit. The charge is negative when the departure of a customer from the IOU load results in lower resource costs for the remaining IOU bundled service customers. The PCIA for the current year (vintage) is assigned to customers upon exit, and that PCIA value is then adjusted over time to reflect market conditions.

C.4.d PG&E and SCE Cost Responsibility Surcharges

CCA customers must also pay the CRS, which is comprised of the Department of Water Resources Bond Charge (DWR-BC), the Competitive Transition Charge (CTC), and the power charge indifference adjustment (PCIA). The CRS, as determined by the CPUC, is intended to protect remaining bundled IOU service customers from incurring additional costs arising from customers leaving the incumbent utility system to join a CCA. It is a mechanism to repay the utility for investments previously made on the CCA customer's behalf. These three components were based on the most recent PG&E and SCE filed rates (March 2017) and escalated over time based on PG&E's PCIA rate forecast as of February 2017.

Table 50 and Table 51 provide the current PG&E and SCE CRS rates by rate class as of March 1, 2017, as used in the pro forma model. In PG&E territory, the CRS makes up 10-28% of a potential CCA customer's generation rate. In SCE territory, where CRS rates are lower, the CRS comprises 5-10% of the CCA generation rate. The difference in CRS rates between PG&E and SCE are attributable to each IOU's unique generation portfolio and associated costs.

Table 50 PG&E CCA CRS by Rate Class as of March 1, 2017

Line	Description	DWR-BC Less Energy Recovery Amount Charge	CTC	PCIA (2017 Vintage)	Total CRS Cost	CCA Generation Rate, AWG Jurisdictions RPS Equivalent Scenario	CRS % of Generation Rate
	Rate Group						
1	Agriculture, PG&E	$0.0055	$0.0010	$0.0213	$0.0278	$0.1200	23%
2	Very Large Comm >1,000kW, PG&E	$0.0055	$0.0007	$0.0153	$0.0215	$0.1100	20%
3	Large Comm 500<1,000kW, PG&E	$0.0055	$0.0008	$0.0189	$0.0252	$0.1100	23%
4	Med Comm 200<500kW, PG&E	$0.0055	$0.0010	$0.0225	$0.0290	$0.1200	24%
5	Small Comm <200kW, PG&E	$0.0055	$0.0010	$0.0220	$0.0285	$0.1200	24%
6	Lighting, PG&E	$0.0055	$0.0002	$0.0042	$0.0099	$0.1000	10%
7	Residential, PG&E	$0.0055	$0.0013	$0.0292	$0.0360	$0.1300	28%
8	Residential CARE, PG&E	($0.0000)	$0.0013	$0.0292	$0.0305	$0.1200	25%
9	Traffic Control, PG&E	$0.0055	$0.0010	$0.0220	$0.0285	$0.1300	22%

Notes
[1] Effective rates as of January 1, 2017

Table 51 SCE CCA CRS by Rate Class as of March 1, 2017

Line	Description	DWR-BC Less Energy Recovery Amount Charge	CTC	PCIA (2017 Vintage)	Total CRS Cost	CCA Generation Rate, AWG Jurisdictions RPS Equivalent Scenario	CRS % of Generation Rate
	Rate Group						
1	Agriculture, SCE	$0.0055	($0.0002)	$0.0040	$0.0093	$0.1326	7%
2	Very Large Comm >1,000kW, SCE	$0.0055	($0.0002)	$0.0040	$0.0093	$0.1299	7%
3	Large Comm 500<1,000kW, SCE	$0.0055	($0.0002)	$0.0046	$0.0099	$0.1213	8%
4	Med Comm 200<500kW, SCE	$0.0055	($0.0002)	$0.0052	$0.0105	$0.1226	9%
5	Small Comm <200kW, SCE	$0.0055	($0.0003)	$0.0059	$0.0111	$0.1240	9%
6	Lighting, SCE	$0.0055	$0.0000	$0.0000	$0.0055	$0.1209	5%
7	Residential, SCE	$0.0055	($0.0003)	$0.0078	$0.0129	$0.1285	10%
8	Residential CARE, SCE	$0.0000	($0.0003)	$0.0078	$0.0074	$0.1277	6%
9	Traffic Control, SCE	$0.0055	($0.0002)	$0.0035	$0.0088	$0.1290	7%

Notes
[1] Effective rates as of January 1, 2017
[2] The PCIA 2017 Non-Continuous rates apply to non-Direct Access customers.

Historically, SCE CRS rates—both of the same vintage and across vintages—have fluctuated up and down, with the 2017 CRS jumping from 2016 levels. However, from 2014-2017, SCE CRS rates decreased by 25-30% (looking at a single vintage [2014] for multiple customer classes) and 31-37% (comparing across vintages [2014-2017] for multiple customer classes). Should the Central Coast Power CCA go forward, however, the PCIA charges would likely increase, perhaps materially, and this has not been examined as part of this analysis. See Section II.E.1 for more detail on historical CRS changes.

C.4.e Franchise Fees

PG&E and SCE's current rates include franchise fees that are in turn paid to a city or county for the nonexclusive right to install and maintain equipment on streets and public rights of way. Franchise fees are included in the incumbent utilities' rates and collected through customers' bills. These franchise fees are calculated on a $ per kWh sold basis. The CCA's Revenue Requirement includes the franchise fees as an expense, and are embedded in the proxy rates, because these fees will need to be collected for CCA customers. Although the CCA does not directly collect or receive the franchise fees, or convey them to the appropriate jurisdictions, they are included to provide an apples-to-apples comparison between the CCA and the incumbent utilities' rates—again the utilities have the franchise fees embedded within them. An alternative method would be to calculate the Revenue Requirement without the franchise fees and then add the fees to the CCA proxy rate. Either method results in the same total rate applied to CCA customers.

C.4.f ESP Charges

The analysis assumed that an ESP would provide energy procurement services as well as the required scheduling coordinator interface to the CAISO. Fees charged were assumed to be $1.50 per customer account per month in year 2020, and over the Study period.

C.4.g Other Start Up Costs

Other startup charges include those costs required to get the CCA up and running and not attributable to startup capital expenditures and investments in longer-lived assets, which are described in more detail under the heading "Capital Expenditures." These other startup costs include CCA establishment fees, costs for communications and notifications, opt-out expenses, and enrollment fees. The other startup charges are assumed to take place in a phased manner beginning in May of 2020 and continuing for one year. As shown in Table 52, Total Startup Charges are estimated to be approximately $623,000 for PG&E and $2.2 million for SCE, or $2.8 million total. The difference in costs between IOUs is attributable to the utilities' differing tariff schedules and number of customers.

Table 52 Other CCA Startup Charges, AWG Jurisdictions Participation Scenario

Line	Description	5/1/2020 Phase I	11/1/2020 Phase II	5/1/2021 Phase III	TOTAL
	PG&E CCA Setup Costs				
1	CCA Establishment	$13,453			$13,453
2	Standard Output Fee (Needed for the Notification Notices)	$669	$1,303	$9,905	$11,878
3	Estimated EDI Testing Charge	$8,969	$8,969	$8,969	$26,906
4	Customer Notification, Initial & Follow-up	$121,102	$121,102	$121,102	$363,307
5	Customer Fees	$10,937	$21,293	$161,828	$194,058
6	Mass Enrollment Fee	$4,475	$4,475	$4,475	$13,425
7	**Subtotal PG&E CCA Setup Costs**	**$159,606**	**$157,142**	**$306,278**	**$623,026**
	SCE CCA Setup Costs				
8	CCA Establishment	$1,150			$1,150
9	Standard Output Fee (Needed for the Notification Notices)	$9,739	$114,372	$758,905	$883,016
10	Estimated EDI Testing Charge	$1,250	$1,250	$1,250	$3,750
11	Customer Notification, Initial & Follow-up	$11,457	$134,555	$892,830	$1,038,842
12	Customer Fees	$2,999	$35,222	$233,711	$271,932
13	Mass Enrollment Fee	$3,479	$3,479	$3,479	$10,437
14	**Subtotal SCE CCA Setup Costs**	**$30,074**	**$288,878**	**$1,890,175**	**$2,209,128**
15	**Total CCA Setup Costs**	**$189,680**	**$446,020**	**$2,196,453**	**$2,832,154**

C.4.h Professional Services

Professional services include engineering, technical, and management consulting; legal and regulatory services; and communication and public outreach services. These professional services are assumed to occur before and after CCA start up and throughout the Study period. Over the initial customer phase-in period, occurring from May 2020 to May 2021, fees totaling $1.2 million were assumed. Upon full operation, annual fees totaling approximately $560,000 per year beginning in year 2022 through the term of the CCA were included in the pro forma model.

C.4.i Jurisdictional Administration

Ongoing costs associated with the Advisory Working Group Jurisdictions administering the CCA were assumed to be approximately $189,000 per year. This fee is assumed to cover jurisdictional staff paid to interface with the CCA. It was assumed that the CCA, rather than the individual participating jurisdictions, would cover this cost since it is directly attributable to the CCA.

C.4.j Other Operating Expenses

Other operating expenses include miscellaneous charges for items such as rentals, professional registrations, travel and other business expenses, utilities, staff development, office supplies, advertising, and computer software and support. These were assumed to be tied to overall expenditures for salaries and wages and ESP charges. As such, and based on industry experience, other operating expenses were calculated as 5.28% of total annual salaries and wages plus ESP charges. For the Test Year, other operating expenses totaled approximately $712,000.

C.4.k Uncollectible Accounts

Uncollectible account expense assumptions were based on the uncollectible expense as reported within 10K filings of PG&E and SCE for 2014, 2015, and 2016. On average over this time period, both utilities reported approximately 0.33% of revenues as uncollectible. This percentage was multiplied by the annual rate revenues received by the CCA as the estimate for accounts that will remain uncollectable (bad debt expense). For the Test Year, uncollectible account expense was approximately $1.8 million.

C.5. Non-Operating Costs

Non-operating costs include initial capital outlays for longer-lived assets required to get the CCA up and running as well as the associated debt issuance and annual debt service required to fund the CCA. Non-Operating Costs also include a contingency and rate stabilization fund.

C.5.a Initial Capital Investments

Initial capital investments include assets such as computers, software, and furnishings, and it is assumed that there is a finite life for each category—meaning over time additional capital investments will need to be made to replace items. Table 53 depicts the categories and non-operating capital investments made initially, as well as the expected useful service lives.

Table 53 CCA Initial Capital Investments

Initial Capital Investments	Total Initial $	Expected Life (years)	Unit Cost (Year 2020)
Individual Staff Computers, Software, and Printers	$85,000	4	$1,700
File Servers, Larger IT Equipment, Telecommunications Equipment	20,000	7	10,000
Furnishings for Individual Offices, Conference Rooms, and Others	35,000	10	700
Appliances and Other Misc. Facility Requirements	10,000	8	5,000
Billing System, Software, and Associated Consulting Support	250,000	10	250,000
Total Initial Capital Investments	$400,000	4	267,400

C.5.b Debt Issuance and Service

The CCA requires significant funding up front and will also need adequate working capital to pay for day-to-day operations, to cover risks associated with power supply costs, other operating costs, customer participation and payment, and a host of other financial drivers. The cost of service analysis assumes the CCA covers these funding requirements through the issuance of long-term debt, in the form of a bond, which is assumed to be the least-cost financing option.

The cost of service analysis relied on debt service assumptions that are conservative in nature. For illustrative purposes, a discussion of CCA cost results for the AWG Jurisdictions RPS Equivalent scenario, and associated debt service assumptions, follow. Additional detail regarding debt issuance and service for the other participation scenarios and renewable energy content scenarios are provided in Appendix C, and E through J in the pro forma results sections.

To calculate the amount of the debt proceeds needed, working capital funding requirements were first calculated. Rounded to the nearest million, average monthly operating expenses for the first two full years of CCA operation, year 2021 and 2022, total $38 million. These operating expenses do not include capital expenditures, debt service, or the contingency/rate stabilization fund. The operating costs included in this amount cover day-to-day expenses including salaries, power costs, charges, and administrative overhead. The cost of service analysis calculated the monthly average operating expenses for the first two full years service (after Phase III) and then assumed five months for funding requirements, based on our experience benchmarking the financial metrics of other utility-type organizations. The CCA's working capital reserve should provide enough cash on hand to cover five months of operating costs, or $188 million.

In addition, adequate cash to fund operating expense contingencies and the rate stabilization fund, as described in further detail in the next segment and as illustrated in Section II.C.5.c Working Capital and Cashflow Analysis, should be in place at the onset of operations. Contingency and rate stabilization funding may be necessary immediately, depending on the number of eligible customers opting out and associated power procurement costs. The cost of service analysis assumed the average annual contingency and rate stabilization fund would be initially funded through debt. Again taking the average of the first two full years of contingency and rate stabilization fund balances (approximately $48 million for the first year and $55 million for the second year) yields an additional $51 million cash requirement. The required working capital funding plus the rate stabilization funding totaled $239 million.

The cost of service analysis assumes that the CCA will issue a long-term (30-year) bond to fund the $239 million cash operating and reserve requirements plus all bond issuance costs, capitalized interest, and a required bond reserve fund. The bond term is standard for a financing of this size and type. The forecasted bond interest rate is 4%, however this number will depend on the prevailing market interest rates as well as credit and financial metrics placed on the CCA by underwriters. Using conservative assumptions, the cost of service analysis includes a bond reserve fund requirement—the CCA is assumed to hold one payment of the maximum annual debt service (principal plus interest) occurring over the life of the bond in a secured fund, approximately $17 million. Given the high level of uncertainty related to power costs, the PCIA, opt-out rates for customers, and opt-up rates for higher-priced renewables, the cost of service analysis assumed the CCA would desire to avoid paying principal payments for two years, and use capitalized interest funding received from the bond proceeds to cover the first two annual interest payments of approximately $11.5 million per year ($23 million total for the first two years). The remaining years' payments over the 30-year bond term would include interest payments and outstanding principal payments. Therefore, the CCA would make interest payments for 30 years and principal payments for 28 years. Issuance costs totaled $8.6 million and were calculated using a rate of 3% of the total bond issuance, including the CCA's $239 million of capital requirements, $17 million of bond reserve funding, $23 million for two years of capitalized interest, and the issuance costs of $8.6 million. Table 54 shows the bond fund proceeds and uses, as well as the first year, second year, and subsequent years of debt service payments.

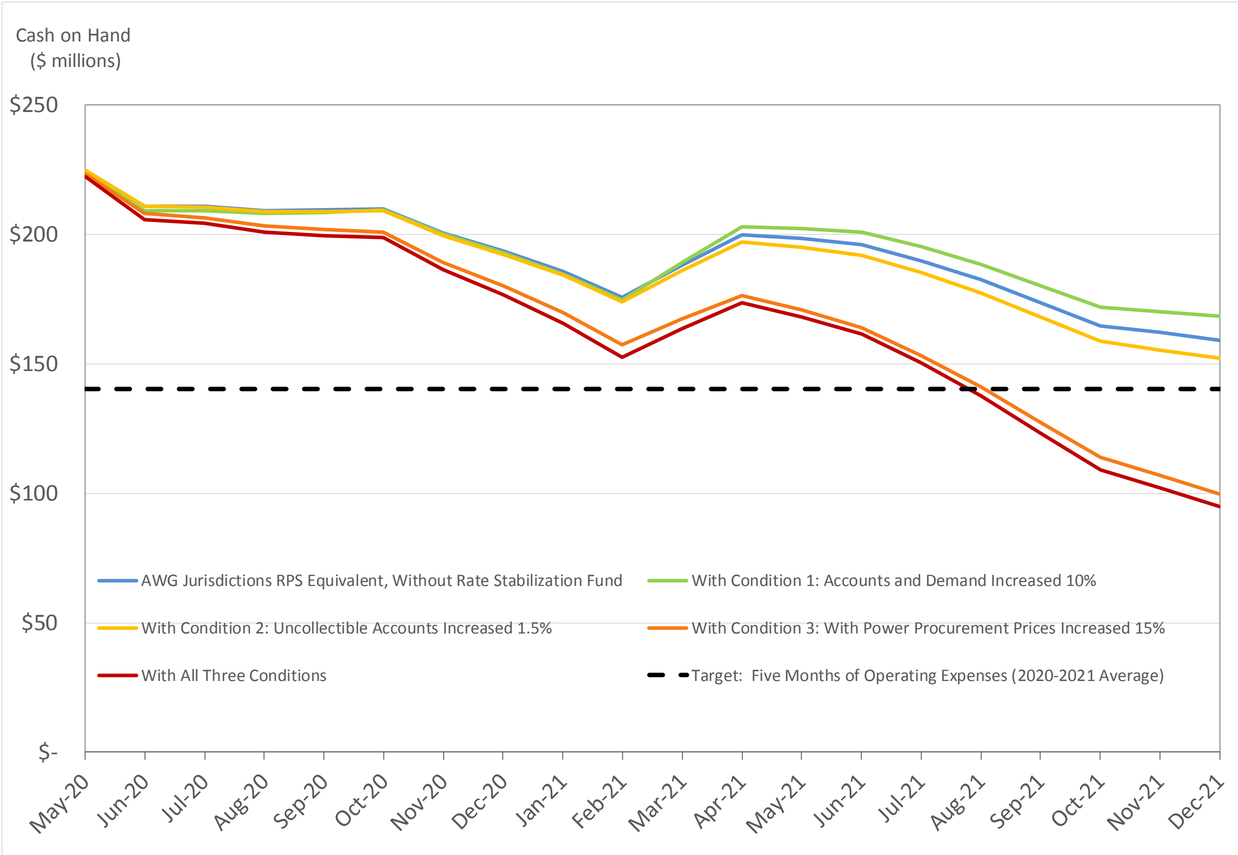
Table 54 Debt Issuance and Annual Debt Service

Funding Requirement	Total Initial
Operating Expenses	$ 187,517,161
Currency, Rate Stabilization Fund	$ 51,405,976
Total CCA Funding	$ 238,923,136
Bond Reserve Fund	$17,275,557
Capitalized Interest	23,029,096
Issuance Costs	$ 8,635,911
Other Bond Funds	$48,940,564
Total Bond Issuance	$287,863,701
Year 1 Interest Payment (Dec. 31, 2020)	$11,514,548
Year 2 Interest Payment (Dec. 31, 2021)	$11,514,548
Year 3 through Year 30 Annual Principal Plus Interest Payments	$17,275,557

C.5.c Working Capital and Cash Flow Analysis

A simple cash flow analysis was conducted for the first two years of operation, 2020 and 2021, to illustrate the need for cash and how unplanned changes in operating costs can impact cash on hand. Figure 52 illustrates the available cash on hand under the AWG Jurisdictions RPS Equivalent scenario and then with different operating conditions examined: 1) with a 10% increase in the number of accounts and electricity demanded (opt-out rate goes from 15% to 5%); 2) with a 1.5% increase in uncollectible accounts over the Study's assumed rate of 0.3325%; 3) with power procurement prices increasing by 15%; and 4) with all three conditions described—an increase in accounts and demand, an increase in uncollectible accounts, and an increase in power procurement pricing. CCA proxy rates are assumed to remain the same. The analysis shows that with power procurement prices increased by 15%, the CCA's cash on hand falls below the target of five months of operating expenses by August 2021, 16 months after beginning operations.

Figure 52 Available Cash on Hand, AWG Jurisdictions RPS Equivalent Scenario and with Alternative, Unplanned Operating Expenses



C.5.d Contingency and Rate Stabilization Fund

A fundamental tenet of rate design should be rate stability. Rates should be stable from a revenue perspective:

- revenues should not change frequently and/or extremely;
- utilities should have a stable income;
- rates should be stable from the customer's perspective; and
- customers should be able to anticipate and plan for their monthly bills.

To mitigate risks associated with higher than expected operating costs, lower than expected participation and revenues, or other deviations from expected circumstances, the cost of service analysis assumes that the CCA will set up a contingency and rate stabilization fund. Within the pro forma analysis, this required funding is deemed a non-operating expense and is part of the cost of service; it is reflected in the CCA rate proxies and is therefore, paid for by customers. This contingency/rate stabilization fund would be used to cover the unexpected costs associated with shorter-term emergent issues, such as an extreme spike in power procurement costs, or to ease the burden on ratepayers resulting from longer-term issues. For example, if a large, long-term rate increase is somehow required, the fund would enable a more gradual increase of rates over time. The rate stabilization and contingency fund was assumed to include adequate cash resources to cover a 10% increase above expected annual non-power operating costs (10%

times the total operating costs less power procurement costs) plus a 12% increase in expected power procurement prices. For the Test Year, this funding expense equated to $55 million. Rate stabilization and contingency fund forecasts for the other scenarios and sensitivity cases can be found in the appropriate Appendices (C through J) by scenario.

D. Rate Analysis

Once the costs associated with the CCA were developed to establish the Revenue Requirement, Revenue Requirements were then allocated to individual rate classes based on cost of service principles. The cost of service analysis followed long-held ratemaking principles grounded in the concept of charging customers cost based rates; recovering service costs from customers based on the costs imposed on the system by that customer. Cost based rates are intended to ensure that the prices paid by customers are fair and reasonable and that there are no intra- or inter-class subsidies, i.e., one group of customers bearing the cost burden caused by another group of customers. For a variety of reasons, often utility rate design will result in intra- and inter-class subsidization. Either intentionally or unintentionally, this means certain customers pay less than their cost responsibility while others pay more to make up the shortfall. The Study has not reviewed or assessed available cost of service analyses or any intra- or inter-class subsidies within PG&E and SCE rates and makes no opinion with respect thereto. Subsidization, if occurring, would impact the rate comparisons between the CCA and IOUs, on an individual class basis. However, the revenue requirements for the CCA and the IOUs are not impacted by subsidization, i.e., the revenue required from customers remains the same—so taken on average rate comparisons between the CCA and IOU can be considered adequate to evaluate overall competitiveness. Please see Appendix B, Section 4. Ratemaking Principles for additional detail on cost of service.

Because the CCA's primary function is to procure power, the cost to serve each customer class was based on how much power supply the customers within the class required. Cost of service-based rates for each class were then adjusted upward or downward across the board to generate revenues sufficient to meet the Revenue Requirement. Rate proxies generated by the cost of service analysis model for each scenario and sensitivity analysis compared with PG&E and SCE rates are provided in the Appendices C through J.

Results from the pro forma model for the AWG Jurisdictions participation scenarios are provided in the following segments. All detailed pro forma results for the 24 scenarios are provided in Appendices C through J, titled by participation scenario.

For reference, Table 55 provides a summary of CCA operating expenses for the AWG Jurisdictions RPS Equivalent scenario by year from the first full year of CCA operations (2022) through 2030. Tables 56 and 57 provide this information for the AWG Jurisdictions Middle of the Road and Aggressive scenarios, respectively.

Table 55 CCA Operating Expenses, AWG Jurisdictions RPS Equivalent Scenario, First Year of Full Operations (2022) through 2030 (Every Other Year)

Line No.	Description	2022	2024	2026	2028	2030
1	Power Procured (MWh)	5,037,474	5,038,110	5,011,148	5,002,887	4,961,931
2	Customer Accounts	339,619	339,638	337,883	337,312	334,630
	Operating Expenses by Category					
3	Salaries & Wages	$ 6,845,988	$ 7,262,908	$ 7,705,219	$ 8,174,467	$ 8,672,292
4	Power Procurement	339,142,570	342,497,002	342,297,753	344,360,025	340,569,448
5	IOU Service Charges	3,533,398	3,676,352	3,805,110	3,952,146	4,079,120
6	IOU CRS Charges	84,855,178	89,920,599	96,898,531	108,040,347	125,081,764
7	IOU Franchise Charges	35,130,690	35,135,385	34,947,665	34,890,455	34,605,271
8	ESP Charges	6,174,276	6,174,620	6,142,711	6,132,329	6,083,572
9	Other Startup Charges	-	-	-	-	-
10	Professional Services	561,710	560,261	560,567	561,079	561,861
11	Jurisdictional Administration	188,939	188,451	188,554	188,727	188,990
12	Other Operating Expenses	701,789	722,412	744,882	770,267	795,552
13	Uncollectable Accounts	$ 1,814,913	$ 1,851,766	$ 1,842,681	$ 1,839,274	$ 1,825,168
14	Total Operating Expenses	$ 478,949,449	$ 487,989,757	$ 495,133,673	$ 508,909,115	$ 522,463,038
	Non-Operating Expenses					
15	Capital	$ -	$ 90,216	$ -	$ 108,224	$ 375,644
16	Debt Service	17,275,557	17,275,557	17,275,557	17,275,557	17,275,557
17	Total Non-Operating Expenses	$ 17,275,557	$ 17,365,773	$ 17,275,557	$ 17,383,781	$ 17,651,201
18	Total Operating & Non-Operating Expenses	$ 496,225,006	$ 505,355,530	$ 512,409,230	$ 526,292,896	$ 540,114,238
19	Contingency/Rate Stabilization Fund	54,677,796	55,648,916	56,359,322	57,778,112	59,057,693
20	**Total Expenses Incl. Contingency**	**$ 550,902,802**	**$ 561,004,445**	**$ 568,768,553**	**$ 584,071,008**	**$ 599,171,931**
21	Average Power Procurement Costs ($/MWh)	$ 67.32	$ 67.98	$ 68.31	$ 68.83	$ 68.64

Table 56 CCA Operating Expenses, AWG Jurisdictions Middle of the Road, First Year of Full Operations (2022) through 2030 (Every Other Year)

Line No.	Description	2022	2024	2026	2028	2030
1	Power Procured (MWh)	5,037,474	5,038,110	5,011,148	5,002,887	4,961,931
2	Customer Accounts	339,619	339,638	337,883	337,312	334,630
	Operating Expenses by Category					
3	Salaries & Wages	$ 6,845,988	$ 7,262,908	$ 7,705,219	$ 8,174,467	$ 8,672,292
4	Power Procurement	370,481,115	366,785,577	359,234,798	353,016,717	340,569,448
5	IOU Service Charges	3,533,398	3,676,352	3,805,110	3,952,146	4,079,120
6	IOU CRS Charges	84,855,178	89,920,599	96,898,531	108,040,347	125,081,764
7	IOU Franchise Charges	35,130,690	35,135,385	34,947,665	34,890,455	34,605,271
8	ESP Charges	6,174,276	6,174,620	6,142,711	6,132,329	6,083,572
9	Other Startup Charges	-	-	-	-	-
10	Professional Services	561,710	560,261	560,567	561,079	561,861
11	Jurisdictional Administration	188,939	188,451	188,554	188,727	188,990
12	Other Operating Expenses	701,789	722,412	744,882	770,267	795,552
13	Uncollectable Accounts	$ 1,925,413	$ 1,964,466	$ 1,954,828	$ 1,951,213	$ 1,936,249
14	Total Operating Expenses	$ 510,398,494	$ 512,391,031	$ 512,182,865	$ 517,677,745	$ 522,574,118
	Non-Operating Expenses					
15	Capital	$ -	$ 90,216	$ -	$ 108,224	$ 375,644
16	Debt Service	18,498,649	18,498,649	18,498,649	18,498,649	18,498,649
17	Total Non-Operating Expenses	$ 18,498,649	$ 18,588,865	$ 18,498,649	$ 18,606,873	$ 18,874,293
18	Total Operating & Non-Operating Expenses	$ 528,897,143	$ 530,979,896	$ 530,681,514	$ 536,284,619	$ 541,448,411
19	Contingency/Rate Stabilization Fund	58,449,472	58,574,815	58,402,982	58,828,109	59,068,801
20	**Total Expenses Incl. Contingency**	**$ 587,346,615**	**$ 589,554,710**	**$ 589,084,496**	**$ 595,112,727**	**$ 600,517,211**
21	Average Power Procurement Costs ($/MWh)	$ 73.55	$ 72.80	$ 71.69	$ 70.56	$ 68.64

Table 57 CCA Operating Expenses, AWG Jurisdictions Aggressive Scenario, First Year of Full Operations (2022) through 2030 (Every Other Year)

Line No.	Description	2022	2024	2026	2028	2030
1	Power Procured (MWh)	5,037,474	5,038,110	5,011,148	5,002,887	4,961,931
2	Customer Accounts	339,619	339,638	337,883	337,312	334,630
	Operating Expenses by Category					
3	Salaries & Wages	$ 6,845,988	$ 7,262,908	$ 7,705,219	$ 8,174,467	$ 8,672,292
4	Power Procurement	428,088,734	426,316,397	421,503,347	416,668,859	403,823,104
5	IOU Service Charges	3,533,398	3,676,352	3,805,110	3,952,146	4,079,120
6	IOU CRS Charges	84,855,178	89,920,599	96,898,531	108,040,347	125,081,764
7	IOU Franchise Charges	35,130,690	35,135,385	34,947,665	34,890,455	34,605,271
8	ESP Charges	6,174,276	6,174,620	6,142,711	6,132,329	6,083,572
9	Other Startup Charges	-	-	-	-	-
10	Professional Services	561,710	560,261	560,567	561,079	561,861
11	Jurisdictional Administration	188,939	188,451	188,554	188,727	188,990
12	Other Operating Expenses	701,789	722,412	744,882	770,267	795,552
13	Uncollectable Accounts	$ 2,152,955	$ 2,196,490	$ 2,185,712	$ 2,181,671	$ 2,164,938
14	Total Operating Expenses	$ 568,233,654	$ 572,153,875	$ 574,682,298	$ 581,560,346	$ 586,056,464
	Non-Operating Expenses					
15	Capital	$ -	$ 90,216	$ -	$ 108,224	$ 375,644
16	Debt Service	20,622,957	20,622,957	20,622,957	20,622,957	20,622,957
17	Total Non-Operating Expenses	$ 20,622,957	$ 20,713,173	$ 20,622,957	$ 20,731,181	$ 20,998,601
18	Total Operating & Non-Operating Expenses	$ 588,856,612	$ 592,867,048	$ 595,305,256	$ 602,291,528	$ 607,055,065
19	Contingency/Rate Stabilization Fund	65,385,140	65,741,715	65,898,297	66,489,412	66,682,108
20	**Total Expenses Incl. Contingency**	**$ 654,241,752**	**$ 658,608,763**	**$ 661,203,552**	**$ 668,780,940**	**$ 673,737,173**
21	Average Power Procurement Costs ($/MWh)	$ 84.98	$ 84.62	$ 84.11	$ 83.29	$ 81.38

This section provides additional assumptions upon which the results are based.

1. All CCA program cited “rates” represent rate proxies or the unitized revenue requirement to be collected from a customer class for the CCA program to be solvent. Rate design was not part of this Study.
2. For the Residential class, the CCA rate proxies for the 2% opting up to 100% renewable content, were compared to PG&E’s and SCE’s green energy tariffs. For all other customer classes and non-100% renewable energy content scenarios, the IOUs’ standard rate for the applicable customer class was used.
3. For this Study, pure cost of service retail rate proxies by customer class were developed. No wholesale energy sales were included or considered.
4. PG&E and SCE’s current rates were escalated based on the market price for energy escalation.
5. With respect to the PCIA, PG&E’s February 2017 forecast filed with the California PUC was used for both IOUs.
6. Delivery charges are the same for IOU bundled and CCA customers.

Results of the AWG Jurisdictions RPS Equivalent scenario indicate that for all rate classes CCA baseline customers will have all-in rates that are higher than PG&E and SCE. The CCA generation proxy rates are higher than both incumbent utilities. Since the delivery component of the total electric bill is the same for customers receiving service from the CCA and IOU bundled customers, the CCA competes against the IOU only on the generation portion of the bill. Figure 53 shows how the total CCA residential customer bill in PG&E territory breaks down between energy, delivery, and exit fee; SCE territory information appears in Figure 54. The relative contribution of the CRS ("exit fee") is larger for PG&E customers than SCE customers due to differences in each utilities' CRS tariffs, which vary based on the underlying generation prices for each IOU's portfolio.

Figure 53 Breakdown of Residential CCA Customer Bill for PG&E Territory, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario, Year 2020

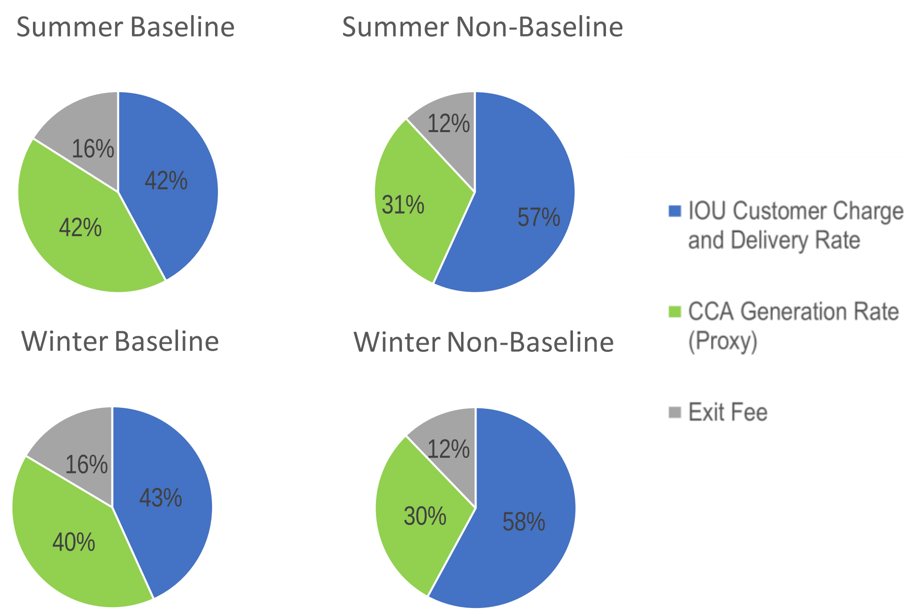


Figure 54 Breakdown of Residential CCA Customer Bill for SCE Territory, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario, Year 2020

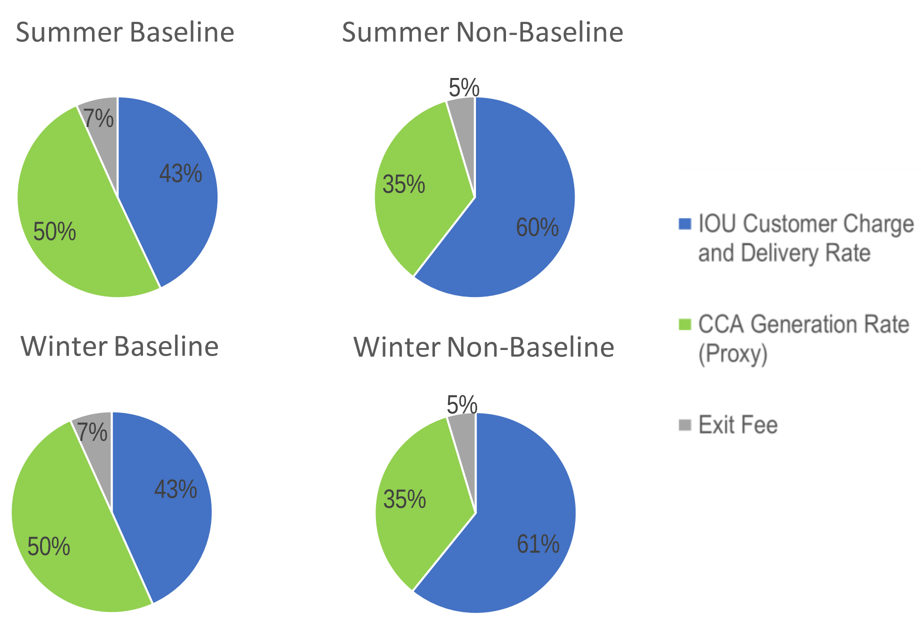


Figure 55 illustrates the trend in the generation component of the average all-in rates for PG&E, SCE, and the CCA from 2022 through 2026 to illustrate the low escalation expected in this component of the customer bill. However, delivery charges could increase significantly over this timeframe, as they have done in the past. Such increases would be borne equally by CCA and bundled IOU customers. Section II.E.1 provides historical perspective on cost shifting by the IOUs between the generation and delivery portion of their rates.

Figure 55 Generation Rate Comparisons for PG&E, SCE, and CCA, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario (2022-2026)

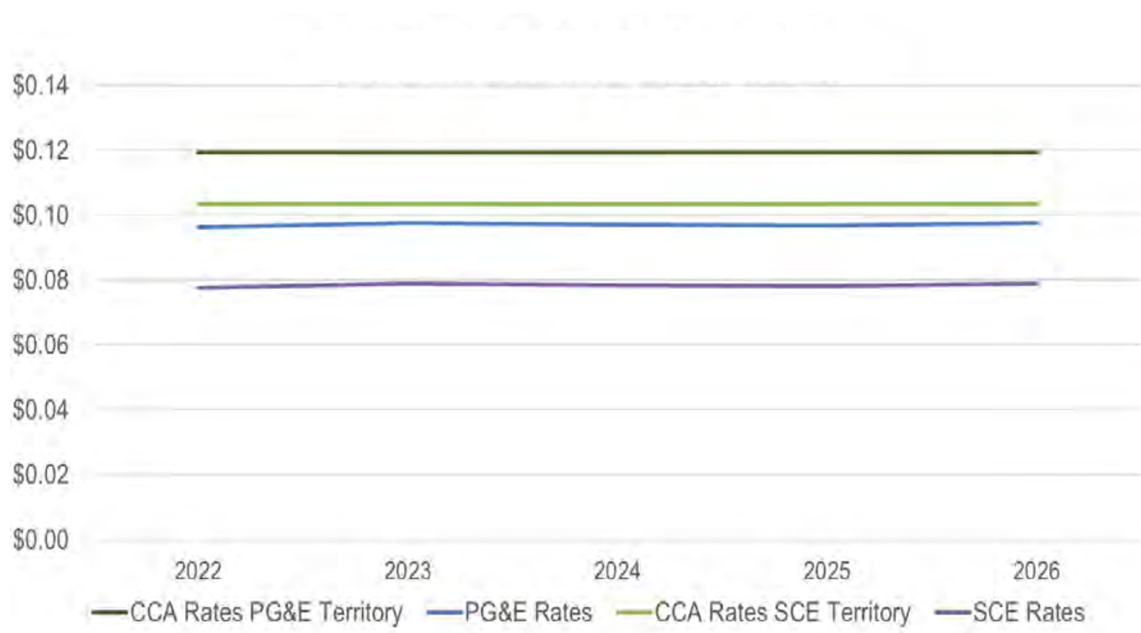


Table 58 through 60 present the generation rate differences between the CCA and PG&E and SCE for the AWG Jurisdictions participation scenarios for the RPS Equivalent, Middle of the Road, and Aggressive renewable energy content scenarios. Rate comparisons are provided for the first five years of the Study period by rate class. If the CCA is not rate competitive within the first five years, it is considered infeasible.

Table 58 Generation Rate Comparisons for PG&E, SCE, and CCA, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Rate Class	2022		2023		2024		2025		2026	
	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates
Agriculture	0.1175	0.0742	0.1175	0.0753	0.1175	0.0749	0.1175	0.0747	0.1175	0.0754
Commercial/Industrial Small <200kW	0.1183	0.1049	0.1183	0.1065	0.1183	0.1059	0.1183	0.1055	0.1183	0.1065
Commercial/Industrial Medium 200<500 kW	0.1190	0.1097	0.1190	0.1113	0.1190	0.1107	0.1190	0.1103	0.1190	0.1114
Commercial/Industrial Large 500<1000 kW	0.1145	0.1107	0.1145	0.1124	0.1145	0.1118	0.1145	0.1114	0.1145	0.1124
Residential	0.1220	0.1003	0.1220	0.1018	0.1220	0.1013	0.1220	0.1009	0.1220	0.1018
Residential CARE	0.1152	0.0936	0.1152	0.0950	0.1152	0.0945	0.1152	0.0941	0.1152	0.0950
Residential Solar Choice	0.1920	0.1265	0.1920	0.1284	0.1920	0.1277	0.1920	0.1272	0.1920	0.1284
Weighted Average	**0.1193**	**0.0961**	**0.1193**	**0.0975**	**0.1193**	**0.0970**	**0.1193**	**0.0967**	**0.1193**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**24.10%**		**22.27%**		**22.92%**		**23.37%**		**22.22%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1050	0.0543	0.1050	0.0551	0.1050	0.0548	0.1050	0.0547	0.1050	0.0552
Commercial/Industrial Small <200kW	0.1072	0.0922	0.1072	0.0936	0.1072	0.0931	0.1072	0.0927	0.1072	0.0936
Commercial/Industrial Medium 200<500 kW	0.1064	0.0837	0.1064	0.0850	0.1064	0.0845	0.1064	0.0842	0.1064	0.0850
Commercial/Industrial Large 500<1000 kW	0.1057	0.0777	0.1057	0.0789	0.1057	0.0785	0.1057	0.0782	0.1057	0.0789
Residential	0.0999	0.0712	0.0999	0.0723	0.0999	0.0719	0.0999	0.0716	0.0999	0.0723
Residential CARE	0.0924	0.0635	0.0924	0.0645	0.0924	0.0641	0.0924	0.0639	0.0924	0.0645
Residential Green Tariff	0.1199	0.1127	0.1199	0.1144	0.1199	0.1138	0.1199	0.1134	0.1199	0.1144
Weighted Average	**0.1034**	**0.0776**	**0.1034**	**0.0788**	**0.1034**	**0.0784**	**0.1034**	**0.0781**	**0.1034**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**33.23%**		**31.26%**		**31.97%**		**32.44%**		**31.21%**

Table 59 Generation Rate Comparisons for PG&E, SCE, and CCA, AWG Jurisdictions Middle of the Road Renewable Energy Content Scenario

Rate Class	2022		2023		2024		2025		2026	
	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates
Agriculture	0.1242	0.0742	0.1242	0.0753	0.1242	0.0749	0.1242	0.0747	0.1242	0.0754
Commercial/Industrial Small <200kW	0.1250	0.1049	0.1250	0.1065	0.1250	0.1059	0.1250	0.1055	0.1250	0.1065
Commercial/Industrial Medium 200<500 kW	0.1257	0.1097	0.1257	0.1113	0.1257	0.1107	0.1257	0.1103	0.1257	0.1114
Commercial/Industrial Large 500<1000 kW	0.1212	0.1107	0.1212	0.1124	0.1212	0.1118	0.1212	0.1114	0.1212	0.1124
Residential	0.1287	0.1003	0.1287	0.1018	0.1287	0.1013	0.1287	0.1009	0.1287	0.1018
Residential CARE	0.1219	0.0936	0.1219	0.0950	0.1219	0.0945	0.1219	0.0941	0.1219	0.0950
Residential Solar Choice	0.1987	0.1265	0.1987	0.1284	0.1987	0.1277	0.1987	0.1272	0.1987	0.1284
Weighted Average	**0.1260**	**0.0961**	**0.1260**	**0.0975**	**0.1260**	**0.0970**	**0.1260**	**0.0967**	**0.1260**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**31.06%**		**29.13%**		**29.82%**		**30.29%**		**29.08%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1117	0.0543	0.1117	0.0551	0.1117	0.0548	0.1117	0.0547	0.1117	0.0552
Commercial/Industrial Small <200kW	0.1139	0.0922	0.1139	0.0936	0.1139	0.0931	0.1139	0.0927	0.1139	0.0936
Commercial/Industrial Medium 200<500 kW	0.1132	0.0837	0.1132	0.0850	0.1132	0.0845	0.1132	0.0842	0.1132	0.0850
Commercial/Industrial Large 500<1000 kW	0.1124	0.0777	0.1124	0.0789	0.1124	0.0785	0.1124	0.0782	0.1124	0.0789
Residential	0.1066	0.0712	0.1066	0.0723	0.1066	0.0719	0.1066	0.0716	0.1066	0.0723
Residential CARE	0.0991	0.0635	0.0991	0.0645	0.0991	0.0641	0.0991	0.0639	0.0991	0.0645
Residential Green Tariff	0.1266	0.1127	0.1266	0.1144	0.1266	0.1138	0.1266	0.1134	0.1266	0.1144
Weighted Average	**0.1102**	**0.0776**	**0.1102**	**0.0788**	**0.1102**	**0.0784**	**0.1102**	**0.0781**	**0.1102**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**41.87%**		**39.78%**		**40.53%**		**41.04%**		**39.72%**

Table 60 Generation Rate Comparisons for PG&E, SCE, and CCA, AWG Jurisdictions Aggressive Renewable Energy Content Scenario

Rate Class	2022 CCA Rates	2022 PG&E Rates	2023 CCA Rates	2023 PG&E Rates	2024 CCA Rates	2024 PG&E Rates	2025 CCA Rates	2025 PG&E Rates	2026 CCA Rates	2026 PG&E Rates
Agriculture	0.1382	0.0742	0.1382	0.0753	0.1382	0.0749	0.1382	0.0747	0.1382	0.0754
Commercial/Industrial Small <200kW	0.1390	0.1049	0.1390	0.1065	0.1390	0.1059	0.1390	0.1055	0.1390	0.1065
Commercial/Industrial Medium 200<500 kW	0.1397	0.1097	0.1397	0.1113	0.1397	0.1107	0.1397	0.1103	0.1397	0.1114
Commercial/Industrial Large 500<1000 kW	0.1352	0.1107	0.1352	0.1124	0.1352	0.1118	0.1352	0.1114	0.1352	0.1124
Residential	0.1426	0.1003	0.1426	0.1018	0.1426	0.1013	0.1426	0.1009	0.1426	0.1018
Residential CARE	0.1359	0.0936	0.1359	0.0950	0.1359	0.0945	0.1359	0.0941	0.1359	0.0950
Residential Solar Choice	0.2026	0.1265	0.2026	0.1284	0.2026	0.1277	0.2026	0.1272	0.2026	0.1284
Weighted Average	**0.1399**	**0.0961**	**0.1399**	**0.0975**	**0.1399**	**0.0970**	**0.1399**	**0.0967**	**0.1399**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**45.56%**		**43.41%**		**44.18%**		**44.70%**		**43.35%**

Rate Class	2022 CCA Rates	2022 SCE Rates	2023 CCA Rates	2023 SCE Rates	2024 CCA Rates	2024 SCE Rates	2025 CCA Rates	2025 SCE Rates	2026 CCA Rates	2026 SCE Rates
Agriculture	0.1258	0.0543	0.1258	0.0551	0.1258	0.0548	0.1258	0.0547	0.1258	0.0552
Commercial/Industrial Small <200kW	0.1280	0.0922	0.1280	0.0936	0.1280	0.0931	0.1280	0.0927	0.1280	0.0936
Commercial/Industrial Medium 200<500 kW	0.1272	0.0837	0.1272	0.0850	0.1272	0.0845	0.1272	0.0842	0.1272	0.0850
Commercial/Industrial Large 500<1000 kW	0.1265	0.0777	0.1265	0.0789	0.1265	0.0785	0.1265	0.0782	0.1265	0.0789
Residential	0.1208	0.0712	0.1208	0.0723	0.1208	0.0719	0.1208	0.0716	0.1208	0.0723
Residential CARE	0.1132	0.0635	0.1132	0.0645	0.1132	0.0641	0.1132	0.0639	0.1132	0.0645
Residential Green Tariff	0.1308	0.1127	0.1308	0.1144	0.1308	0.1138	0.1308	0.1134	0.1308	0.1144
Weighted Average	**0.1242**	**0.0776**	**0.1242**	**0.0788**	**0.1242**	**0.0784**	**0.1242**	**0.0781**	**0.1242**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**59.94%**		**57.58%**		**58.43%**		**59.00%**		**57.52%**

Figure 56 and Figure 57 graphically depict the difference in rates between the CCA and PG&E and the CCA and SCE, respectively, for the AWG Jurisdictions scenarios.

Figure 56 CCA and PG&E Generation Rate Comparison Summary for AWG Jurisdiction Participation Scenarios

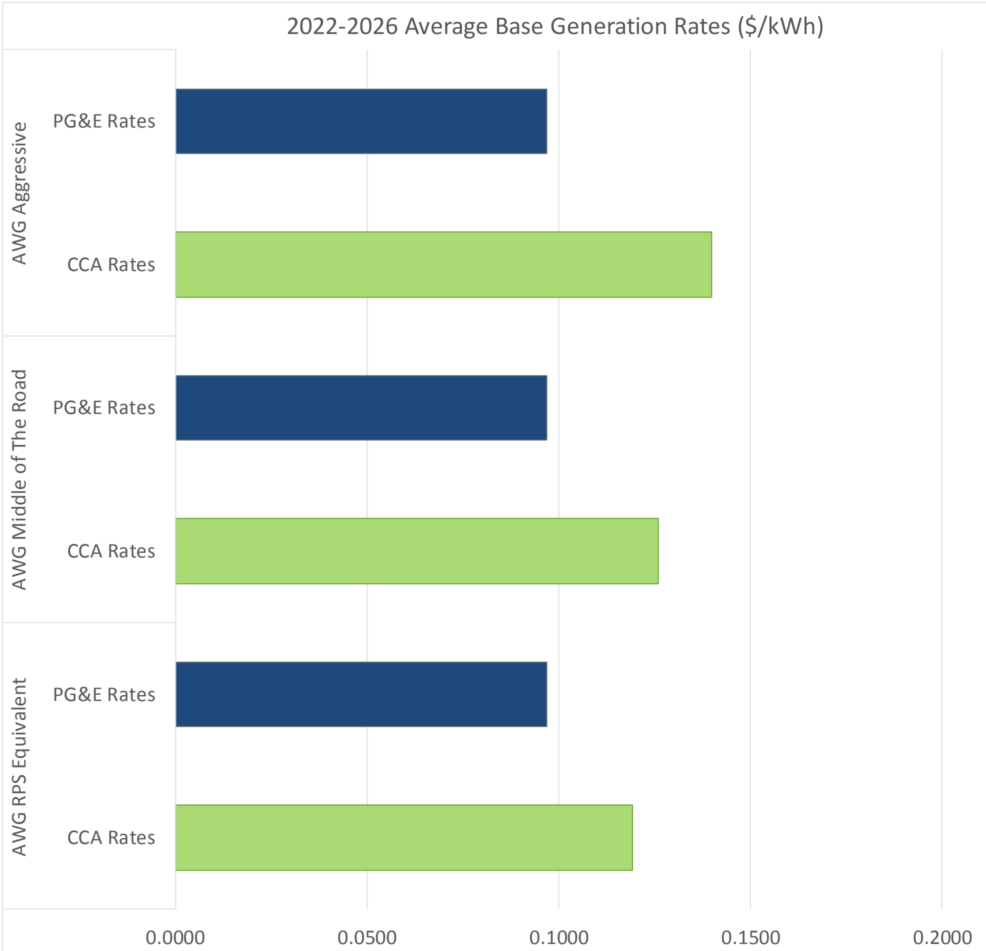
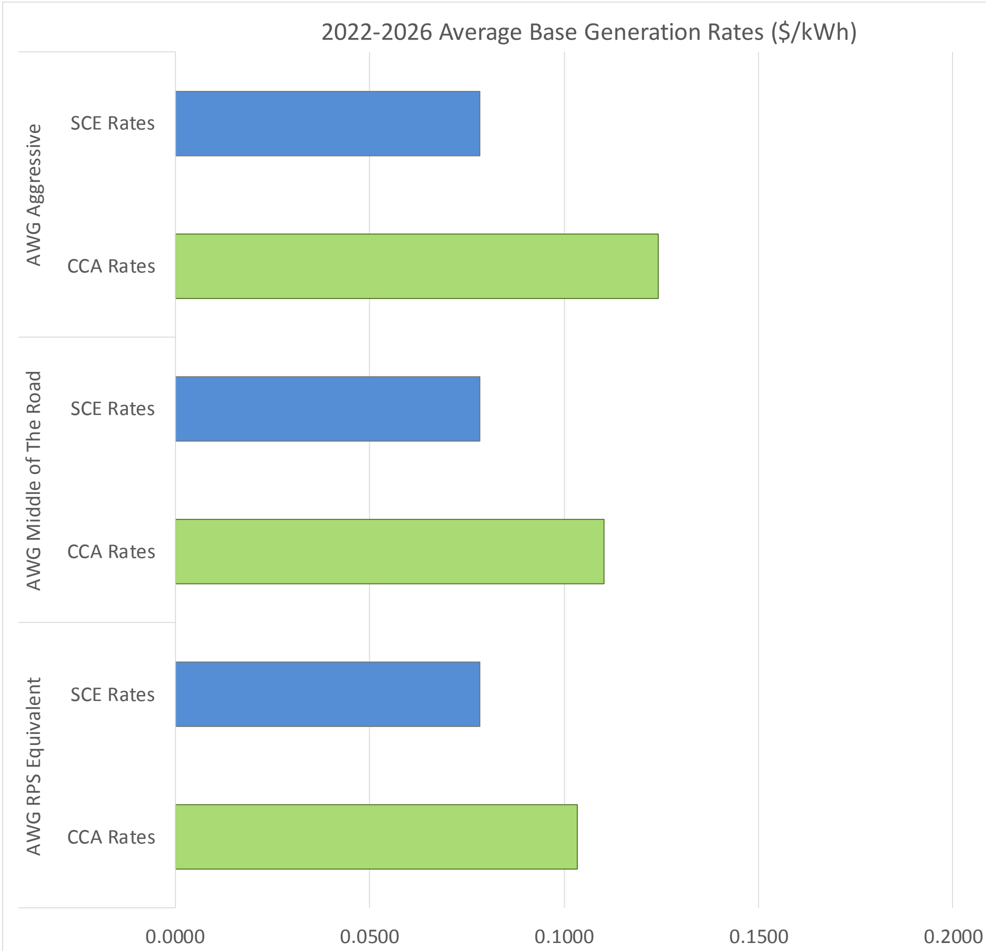


Figure 57 CCA and SCE Generation Rate Comparison Summary for AWG Jurisdiction Participation Scenarios



E. Pro Forma Analysis

Table 61 shows annual operating results for the AWG Jurisdictions RPS Equivalent scenario. Net operating margins are negative for each year of the Study period; meaning revenues are not sufficient to cover total operating and non-operating expenses plus the contingency rate stabilization fund. In the initial years of the study period, this is due to the phasing in of customers and a lag in revenues versus expenditures. In the later years, this revenue insufficiency is caused by rates remaining unchanged even though the CCA experiences an increase in operating costs. Rates were not increased because the CCA rate proxies were not competitive with IOU rates from the onset of the Study through 2026. Although there is adequate working capital initially, given the current debt assumptions that include a long-term bond financing in year 2020 of $288 million, by 2024, working capital declines below targeted amounts. The combination of increasingly negative net margins and a shortage of working capital would indicate the need for a rate increase around year 2026, which would further harm the CCA's rate competitiveness relative to the IOUs.

In no participation or renewable energy content scenario were the CCA's rates competitive with PG&E or SCE. Given the underperformance of the CCA in terms of being rate competitive, consistently having negative net margins, and failing to meet the target for working capital, the CCA under the assumptions used in the analysis is neither reliably solvent nor financially feasible.

Table 61: CCA Annual Operating Results, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario

Year	Operating Revenues ($000s)	Total Operating Expenses Plus Contingency/ Rate Stabilization Fund ($000s)	Non-Operating Revenues/ (Expenses) ($000s)	Debt Service ($000s)	Net Margin[1] ($000s)	Working Capital Fund ($000s)	Working Capital Target ($000s)	Working Capital Surplus/ (Deficiency) ($000s)	Working Capital Surplus/ (Deficiency) (%)
	a	b	c	d	a - b + c - d	e	f	e - f	(e/f)-1
2020	110,694	139,109	1,145	11,515	(38,785)	211,653	47,077	164,575	350%
2021	445,293	469,267	2,227	11,515	(33,262)	189,905	159,570	30,335	19%
2022	545,838	533,627	2,046	17,276	(3,018)	186,887	181,993	4,894	3%
2023	556,361	541,735	2,028	17,276	(621)	186,266	184,808	1,458	1%
2024	556,922	543,639	1,925	17,276	(2,067)	184,199	185,916	(1,716)	-1%
2025	555,121	543,720	1,985	17,276	(3,889)	180,310	186,453	(6,143)	-3%
2026	554,190	551,493	1,903	17,276	(12,676)	167,634	189,470	(21,836)	-12%
2027	553,316	556,757	1,721	17,276	(18,995)	148,639	191,885	(43,246)	-23%
2028	553,165	566,687	1,396	17,276	(29,401)	119,238	195,934	(76,697)	-39%
2029	550,808	569,985	1,183	17,276	(35,270)	83,967	198,148	(114,181)	-58%
2030	548,923	581,521	386	17,276	(49,488)	34,479	203,224	(168,745)	-83%
				NPV of Net Margin:	(176,175)				

[1] Net Margin includes Net Operating Income less Debt Service. The net present value (NPV) of the Net Margin is determined using a 4% discount rate and is as of Year 2020. The discount rate is equal to the interest rate on the long-term debt.

Table 62 presents this data for the AWG Jurisdictions Middle of the Road renewable energy content scenario and Table 63 presents this data for the AWG Jurisdictions Aggressive renewable energy content scenario. Generally speaking, results for these alternate renewable energy content scenarios are similar to the RPS Equivalent scenario, although net margins and working capital deficiencies are better due to the higher rate proxies, which are set at the beginning and remain constant throughout the study period. Rate increases would still be required, but around the 2028 timeframe.

Table 62: CCA Annual Operating Results, AWG Jurisdictions Middle of the Road Scenario

Year	Operating Revenues ($000s)	Total Operating Expenses Plus Contingency/ Rate Stabilization Fund ($000s)	Non-Operating Revenues/ (Expenses) ($000s)	Debt Service ($000s)	Net Margin[1] ($000s)	Working Capital Fund ($000s)	Working Capital Target ($000s)	Working Capital Surplus/ (Deficiency) ($000s)	Working Capital Surplus/ (Deficiency) (%)
	a	b	c	d	a - b + c - d	e	f	e - f	(e/f)-1
2020	117,525	150,875	1,235	12,330	(44,445)	223,724	50,583	173,141	342%
2021	472,491	504,655	2,323	12,330	(42,170)	193,883	170,117	23,766	14%
2022	579,072	568,848	2,082	18,499	(6,192)	187,691	192,494	(4,803)	-2%
2023	590,222	575,366	2,044	18,499	(1,600)	186,092	194,836	(8,745)	-4%
2024	590,817	570,966	1,962	18,499	3,314	189,406	194,067	(4,662)	-2%
2025	588,906	566,609	2,098	18,499	5,896	195,302	193,284	2,019	1%
2026	587,918	570,586	2,132	18,499	966	196,268	195,171	1,096	1%
2027	586,991	571,282	2,109	18,499	(681)	195,587	196,227	(640)	0%
2028	586,831	576,506	1,991	18,499	(6,182)	189,405	198,875	(9,470)	-5%
2029	584,330	574,978	2,033	18,499	(7,113)	182,292	199,652	(17,361)	-9%
2030	582,330	581,643	1,541	18,499	(16,270)	166,022	203,279	(37,257)	-18%
				NPV of Net Margin:	(100,693)				

[1] Net Margin includes Net Operating Income less Debt Service. The net present value (NPV) of the Net Margin is determined using a 4% discount rate and is as of Year 2020. The discount rate is equal to the interest rate on the long-term debt.

Table 63: CCA Annual Operating Results, AWG Jurisdictions Aggressive Scenario

Year	Operating Revenues ($000s)	Total Operating Expenses Plus Contingency/ Rate Stabilization Fund ($000s)	Non-Operating Revenues/ (Expenses) ($000s)	Debt Service ($000s)	Net Margin[1] ($000s)	Working Capital Fund ($000s)	Working Capital Target ($000s)	Working Capital Surplus/ (Deficiency) ($000s)	Working Capital Surplus/ (Deficiency) (%)
	a	b	c	d	a - b + c - d	e	f	e - f	(e/f)-1
2020	131,724	168,193	1,428	13,746	(48,788)	250,176	55,745	194,431	349%
2021	528,600	562,520	2,607	13,746	(45,059)	218,863	187,370	31,493	17%
2022	647,505	633,619	2,361	20,623	(4,375)	214,487	211,809	2,679	1%
2023	659,933	646,015	2,318	20,623	(4,388)	210,100	215,901	(5,801)	-3%
2024	660,598	637,896	2,227	20,623	4,307	214,407	214,025	381	0%
2025	658,462	633,821	2,370	20,623	6,388	220,795	213,325	7,469	4%
2026	657,357	640,581	2,395	20,623	(1,452)	219,343	216,041	3,302	2%
2027	656,320	642,137	2,343	20,623	(4,096)	215,247	217,353	(2,106)	-1%
2028	656,142	648,050	2,187	20,623	(10,344)	204,903	220,206	(15,303)	-7%
2029	653,345	646,843	2,185	20,623	(11,936)	192,967	221,079	(28,111)	-13%
2030	651,109	652,739	1,647	20,623	(20,605)	172,362	224,476	(52,114)	-23%
				NPV of Net Margin:	(120,434)				

[1] Net Margin includes Net Operating Income less Debt Service. The net present value (NPV) of the Net Margin is determined using a 4% discount rate and is as of Year 2020. The discount rate is equal to the interest rate on the long-term debt.

E.1. Feasibility Drivers

As discussed, the two primary factors driving forecasted feasibility results for the CCA include: 1) the competitiveness of CCA rates against PG&E and SCE rates and 2) the long-term financial viability of the enterprise. Regarding rate competitiveness, forecasted CCA revenue requirements are driven by power procurement costs and the Cost Responsibility Surcharge (CRS), which consists of the Competitive Transition Charge (CTC), the Department of Water Resources Bond Charge (DWR-BC), and the Power Cost Indifference Adjustment (PCIA). Together, these two portions represent 78% of the total of the overall projected CCA revenue requirement and are thus primary drivers of rate competitiveness against the two incumbent utilities. Regarding long-term financial viability, the CCA would need additional rate increases around the year 2026 timeframe to maintain adequate working capital and increase net margins. Such an increase would further decrease rate competitiveness.

Recent historical movements in the CRS and the allocation of incumbent utility revenue requirements between generation and transmission and distribution (the delivery portions of customers' bills) is discussed in more detail in the following segments. Generally speaking, in recent years the incumbent utilities appear to have been shifting costs from generation to delivery. The CCA can only compete against the incumbent utilities on generation. SCE and PG&E forecasted generation rates are not high enough to support CCA feasibility at the forecasted level of power procurement and operational costs.

Table 64 shows the SCE CRS rate changes for the Residential and Residential CARE (low-income) classes that have occurred since 2014. The top set of numbers show changes in the CRS by different vintage years, 2014 through 2017, while the bottom set of numbers show changes within one specific vintage year—2014.

Table 64 SCE CRS Rate Changes Since 2014, Residential and Residential CARE Rate Classes

		Eff 6/1/2014	Eff 11/18/2015	Eff 1/1/2016	Eff 1/1/2017	% Change
CCA-CRS-Various		**Vintage 2014**	**Vintage 2015**	**Vintage 2016**	**Vintage 2017**	**2014-2017**
DWR-BC	$/kWh	0.00513	0.00526	0.00539	0.00549	
CTC	$/kWh	(0.00195)	(0.00195)	(0.00015)	(0.00034)	
PCIA	..	0.01740	0.00646	0.00098	0.00776	
Total CCA-CRS	$/kWh	0.02058	0.00977	0.00622	0.01291	
Increase/Decrease			*-53%*	*-36%*	*108%*	*-37%*
		Eff 6/1/2014	**Eff 1/1/2015**	**Eff 1/1/2016**	**Eff 1/1/2017**	
CCA-CRS - 2014		**Vintage 2014**	**Vintage 2014**	**Vintage 2014**	**Vintage 2014**	
DWR-BC	$/kWh	0.00513	0.00526	0.00539	0.00549	
CTC	$/kWh	(0.00195)	(0.00195)	(0.00015)	(0.00034)	
PCIA	$/kWh	0.01740	0.01241	0.00218	0.00920	
Total CCA-CRS	$/kWh	0.02058	0.01572	0.00742	0.01435	
Increase/Decrease			*-24%*	*-53%*	*93%*	*-30%*

This data illustrates there was a period of declining CRS charges from 2015 to 2016, followed by increases in 2017. The current CRS charges, whether looking at various vintage years or the single vintage year of 2014, are lower than they were three years ago, but higher than they were last year, more than doubling when comparing the 2017 vintage to the 2016 vintage and nearly doubling when looking at the 2014 vintage from 2016 to 2017.

Tables 65 and 66 provide the same data for the Medium Commercial and Large Commercial rate comparisons used within the feasibility Study. CRS charges for the Commercial rate classes follow the same general pattern experienced by the Residential rate classes.

Table 65 SCE CRS Rate Changes Since 2014, Medium Commercial Rate Classes (TOU GS-3)

		Eff 6/1/2014	Eff 11/18/2015	Eff 1/1/2016	Eff 1/1/2017	% Change
CCA-CRS - Various		**Vintage 2014**	**Vintage 2015**	**Vintage 2016**	**Vintage 2017**	**2014-2017**
DWR-BC	$/kWh	0.00513	0.00526	0.00539	0.00549	
CTC	$/kWh	(0.00131)	(0.00131)	(0.00011)	(0.00023)	
PCIA	$/kWh	0.01174	0.00436	0.00070	0.00524	
Total CCA-CRS	$/kWh	0.01556	0.00831	0.00598	0.01050	
Increase/Decrease			*-47%*	*-28%*	*76%*	*-33%*
		Eff 6/1/2014	**Eff 1/1/2015**	**Eff 1/1/2016**	**Eff 1/1/2017**	
CCA-CRS - 2014		**Vintage 2014**	**Vintage 2014**	**Vintage 2014**	**Vintage 2014**	
DWR-BC	$/kWh	0.00513	0.00526	0.00539	0.00549	
CTC	$/kWh	(0.00131)	(0.00131)	(0.00011)	(0.00023)	
PCIA	$/kWh	0.01174	0.00838	0.00155	0.00621	
Total CCA-CRS	$/kWh	0.01556	0.01233	0.00683	0.01147	
Increase/Decrease			*-21%*	*-45%*	*68%*	*-26%*

Table 66 SCE CRS Rate Changes Since 2014, Large Commercial Rate Classes (TOU-8 Option B)

		Eff 6/1/2014	Eff 11/18/2015	Eff 1/1/2016	Eff 1/1/2017	% Change
CCA-CRS - Various		**Vintage 2014**	**Vintage 2015**	**Vintage 2016**	**Vintage 2017**	**2014-2017**
DWR-BC	$/kWh	0.00513	0.00526	0.00539	0.00549	
CTC	$/kWh	(0.00115)	(0.00099)	(0.00010)	(0.00020)	
PCIA	$/kWh	0.01023	0.00329	0.00061	0.00457	
Total CCA-CRS	$/kWh	0.01421	0.00756	0.00590	0.00986	
Increase/Decrease			*-47%*	*-22%*	*67%*	*-31%*
CCA-CRS - 2014						
DWR-BC	$/kWh	0.00513	0.00526	0.00539	0.00549	
CTC	$/kWh	(0.00115)	(0.00115)	(0.00010)	(0.00020)	
PCIA	$/kWh	0.01023	0.00730	0.00136	0.00541	
Total CCA-CRS	$/kWh	0.01421	0.01141	0.00665	0.01070	
Increase/Decrease			*-20%*	*-42%*	*61%*	*-25%*

Unfortunately, this type of historical CRS data was not available for PG&E; PG&E does not post historical tariffs on its website and provides only bundled data for previous years' rates.

Table 67 shows historical generation and delivery charges for SCE for the Residential rate class since 2014, for the CPUC-designated "baseline" consumption. Overall for this period, the delivery charge has increased 89%, while the energy component has decreased 13%.

Table 67 SCE Rate Changes Since 2014, Residential Baseline

		2014	2015	2016	2017	% Change 2014-2017
RESIDENTIAL, Baseline Usage						
Basic Service Fee	$/Meter/ Month	0.94292	0.94292	0.94292	0.94292	
Energy						
Summer	$/kWh	0.08555	0.0899	0.06887	0.07477	
Winter	$/kWh	0.08555	0.0899	0.06887	0.07477	
Increase/Decrease			*5%*	*-23%*	*9%*	*-13%*
Delivery						
Summer	$/kWh	0.04678	0.0586	0.08221	0.0884	
Winter	$/kWh	0.04678	0.0586	0.08221	0.0884	
Increase/Decrease			*25%*	*40%*	*8%*	*89%*
California Climate Credit		$0.00	($4.83)	($6.33)	($5.17)	

Tables 68 and 69 show the historical rate changes occurring for the Medium and Large Commercial classes, respectively. Overall for this period, the delivery charges increased and the generation charges decreased for both classes.

Table 68 SCE Rate Changes Since 2014, Medium Commercial

		2014	2015	2016	2017	% Change 2014-2017
GENERAL SERVICE, TOU-GS-3						
Basic Service Fee	$/Meter/ Month	444.790	441.930	493.360	446.130	
Increase/Decrease			*-1%*	*12%*	*-10%*	*0%*
Energy						
Summer						
On-Peak	$/kWh	0.30087	0.33132	0.23913	0.28916	
Increase/Decrease			*10%*	*-28%*	*21%*	*-4%*
Mid-Peak	$/kWh	0.10158	0.1119	0.08078	0.08281	
Increase/Decrease			*10%*	*-28%*	*3%*	*-18%*
Off-Peak	$/kWh	0.03227	0.03555	0.02568	0.03226	
Increase/Decrease			*10%*	*-28%*	*26%*	*0%*
Winter						
Mid-Peak	$/kWh	0.05581	0.06148	0.04537	0.04662	
Increase/Decrease			*10%*	*-26%*	*3%*	*-16%*
Off-Peak	$/kWh	0.03681	0.04055	0.02927	0.03712	
Increase/Decrease			*10%*	*-28%*	*27%*	*1%*
Voltage Discount, Energy						
50kV<220kV	$/kW	(0.00404)	(0.00440)	(0.00320)	(0.00461)	
Increase/Decrease			*9%*	*-27%*	*44%*	*14%*
Delivery						
Summer						
On-Peak	$/kWh	0.02332	0.02691	0.02557	0.02718	
Increase/Decrease			*15%*	*-5%*	*6%*	*17%*
Mid-Peak	$/kWh	0.02332	0.02691	0.02557	0.02718	
Increase/Decrease			*15%*	*-5%*	*6%*	*17%*
Off-Peak	$/kWh	0.02332	0.02691	0.02557	0.02718	
Increase/Decrease			*15%*	*-5%*	*6%*	*17%*
Winter						
Mid-Peak	$/kWh	0.02332	0.02691	0.02557	0.02718	
Increase/Decrease			*15%*	*-5%*	*6%*	*17%*
Off-Peak	$/kWh	0.02332	0.02691	0.02557	0.02718	
Increase/Decrease			*15%*	*-5%*	*6%*	*17%*
Demand Charges						
Facilities Related	$/kW	$16.14	$16.07	$18.45	$17.81	
Increase/Decrease			*0%*	*15%*	*-3%*	*10%*
Voltage Discount, Demand						
Facilities Related						
50kV<220kV	$/kW	(6.76000)	(6.71000)	(7.46000)	(6.79000)	
Increase/Decrease			*-1%*	*12%*	*-21%*	*-12%*

Table 69 SCE Rate Changes Since 2014, Large Commercial

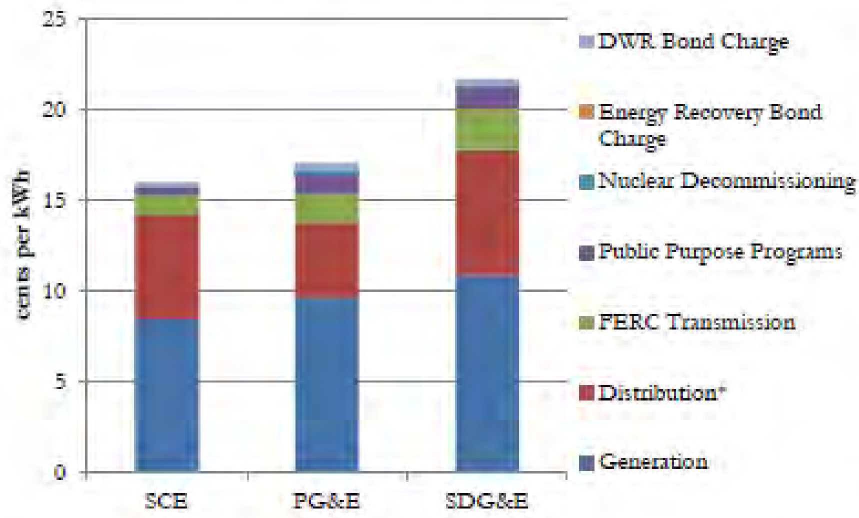
		2014	2015	2016	2017	% Change 2014-2017
GENERAL SERVICE-LARGE, TOU-8-Option B						
Basic Service Fee	$/Meter/ Month	321.60	319.47	356.41	303.25	
Increase/Decrease			*-1%*	*12%*	*-15%*	*-6%*
Energy						
Summer						
On-Peak	$/kWh	0.10485	0.11445	0.08309	0.07072	
Increase/Decrease			*9%*	*-27%*	*-15%*	*-33%*
Mid-Peak	$/kWh	0.05449	0.05948	0.04318	0.04730	
Increase/Decrease			*9%*	*-27%*	*10%*	*-13%*
Off-Peak	$/kWh	0.03241	0.03537	0.02568	0.03165	
Increase/Decrease			*9%*	*-27%*	*23%*	*-2%*
Winter						
Mid-Peak	$/kWh	0.05616	0.06130	0.04451	0.04579	
Increase/Decrease			*9%*	*-27%*	*3%*	*-18%*
Off-Peak	$/kWh	0.03738	0.04081	0.02963	0.03645	
Increase/Decrease			*9%*	*-27%*	*23%*	*-2%*
Demand Charges						
Time Related						
Summer						
On-Peak	$/kW	28.23	30.81	22.38	22.55	
Increase/Decrease			*9%*	*-27%*	*1%*	*-20%*
Mid-Peak	$/kW	0.00	0.00	0.00	3.63	
Increase/Decrease			*0%*	*0%*	*N/A*	
Delivery						
Summer						
On-Peak	$/kWh	0.02162	0.02463	0.02331	0.02426	
Increase/Decrease			*14%*	*-5%*	*4%*	*12%*
Mid-Peak	$/kWh	0.02162	0.02463	0.02331	0.02426	
Increase/Decrease			*14%*	*-5%*	*4%*	*12%*
Off-Peak	$/kWh	0.02162	0.02463	0.02331	0.02426	
Increase/Decrease			*14%*	*-5%*	*4%*	*12%*
Winter						
Mid-Peak	$/kWh	0.02162	0.02463	0.02331	0.02426	
Increase/Decrease			*14%*	*-5%*	*4%*	*12%*
Off-Peak	$/kWh	0.02162	0.02463	0.02331	0.02426	
Increase/Decrease			*14%*	*-5%*	*4%*	*12%*
Demand Charges						
Facilities Related	$/kW	11.64	14.88	16.89	18.34	
Increase/Decrease			*28%*	*14%*	*9%*	*58%*

Unfortunately, this type of historical delivery data was not available for PG&E; PG&E does not post historical tariffs on its website and provides only bundled data for previous years' rates.

However, the California Public Utilities Commission April 2016 report entitled "Electric and Gas Utility Cost Report" provides illustrative data comparisons between the rates and Revenue Requirements of the three state IOUs: PG&E, SCE, and San Diego Gas and Electric (SDG&E). Information from that report has been included for illustrative purposes.

Figure 58 shows the overall rate levels for the three California IOUs for 2015 and the component parts. SCE and SDG&E appear to have about half of their rates attributable to the generation component, with PG&E having more than half, estimated around 60%.

Figure 58 From CPUC, 2015 Rate Components for the Three California IOUs



*Distribution here includes some charges not related to distribution, but recovered through the Delivery Component of rates from all customers, both bundled and unbundled. These charges total 0.4¢ for SCE, -0.8¢ for PG&E and 0¢ for SDG&E.

Table 70 shows that in 2015 for PG&E, distribution and transmission (i.e., delivery) account for approximately 44% of its total Revenue Requirement, in line with SCE at 43% and SDG&E at 44%. Generation accounts for 48% of its Revenue Requirement, in line with SCE at 48% and higher than SDG&E at 40%.

Table 70 From CPUC, 2015 Electric IOU Revenue Requirements ($000s)

	PG&E	SCE	SDG&E
Generation/Energy Procurement			
Purchased Power	$4,514,153	$4,412,244	$1,008.008
Utility Owned Generation	$2,185,558	$1,513,067	$399,351
Distribution	$4,399,854	$4,350,777	$1,138,103
Transmission	$1,610,878	$910,155	$423,318
Demand Side Management and Public Purpose Programs	$646,788	$545,126	$162,987
Bonds and Fees	$673,170	$485,956	$131,756
Total 2015 Revenue Requirement[*]	**$13,730,664**	**$12,198,048**	**$3,578,637**
Numbers do not add up to the total 2015 Revenue Requirement for each utility due to other costs that do not fall under the categories provided here.			

Figures 59 and 60 show transmission and distribution Revenue Requirements over time, which have been more or less consistently growing for each of the three IOUs since 2005.

Figure 59 From CPUC, Trends in Transmission Revenue Requirements for the Three California IOUs

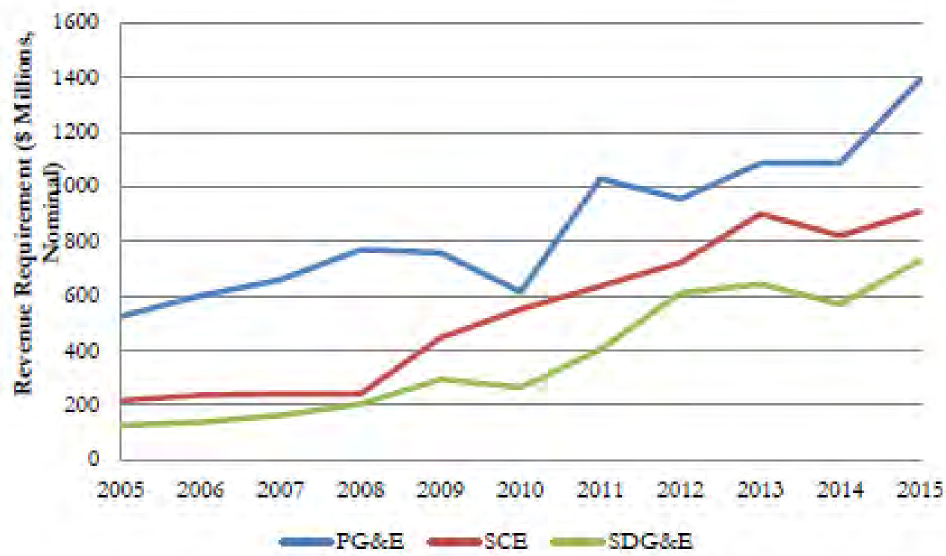


Figure 60 From CPUC, Trends in Distribution Revenue Requirements for the Three California IOUs

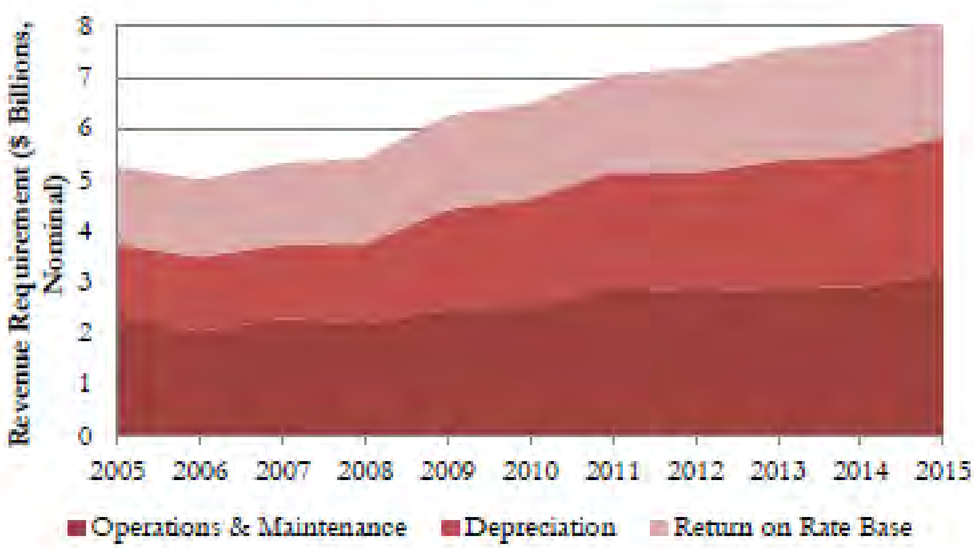
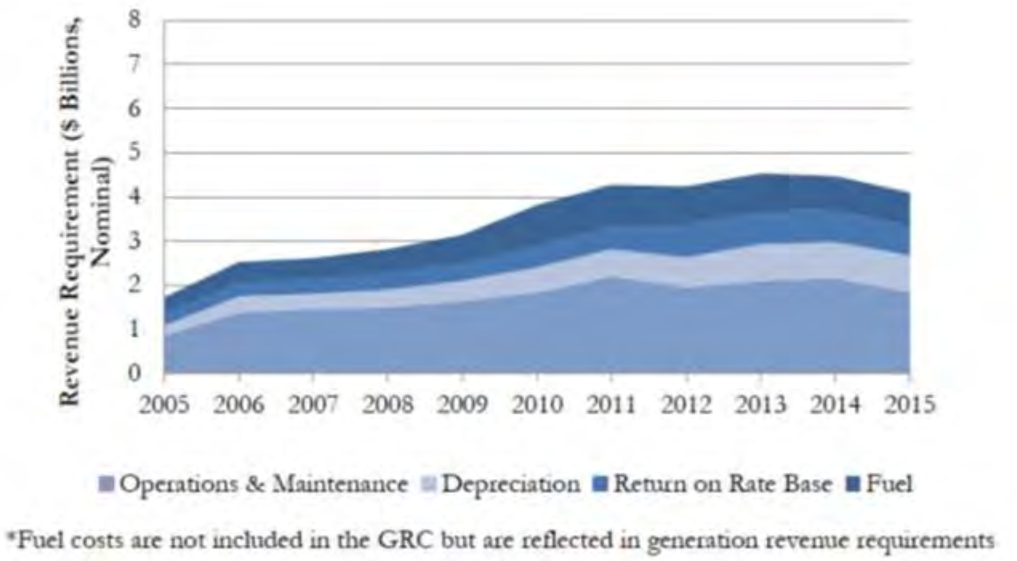


Figure 61 shows the generation Revenue Requirements over time; year 2015 generation Revenue Requirements are lower than 2014 and currently near the 2011 levels.

Figure 61 From CPUC, Trends in Generation Revenue Requirements for the Three California IOUs



Assuming PG&E follows the combined trends for the three utilities, this data would indicate that transmission and distribution is making up a larger portion of the total Revenue Requirement for the utility. This would, theoretically, justify a higher fixed component of rates—shifting revenues from generation-related charges to delivery-related charges.

E.2. Pro Forma Sensitivity Analyses

Upon arrival at Study outcomes for each participation and renewable energy content scenario, additional sensitivity cases were examined, against the AWG Jurisdictions scenario, to determine how changes in key inputs affected feasibility outcomes. Decreases in power procurement costs, increases in incumbent utility rate escalation, and decreases in staffing costs were examined individually at various levels to determine at what point could the CCA be feasible. In order for the CCA to be feasible, power procurement costs would have to decrease 40% over the Study forecast or PG&E and SCE rates would have to escalate at an additional 4.0% per year above the Study forecast. A staffing cost reduction of 70% over the Study assumption still would not enable a feasible outcome, as staffing costs contribute a relatively small percentage of total operating costs. A brief discussion of each sensitivity analysis is described in the following sections.

E.2.a Power Procurement Cost Sensitivity

Table 71 depict the difference in average power procurement costs between the AWG Jurisdictions scenarios and the 30% decrease in power procurement costs and 40% decrease in power procurement costs sensitivity cases.

Table 71 Average Power Procurement Costs, AWG Jurisdictions Scenarios and with 30% Decrease in Power Procurement Costs, and with 40% Decrease in Power Procurement Costs

	AWG Jurisdictions RPS Equivalent Scenario			AWG Jurisdictions Middle of the Road Scenario			AWG Jurisdictions Aggressive Scenario		
Year	Original Power Procurement Cost ($ per MWh)	With Power Procurement Cost 30% Lower ($ per MWh)	With Power Procurement Cost 40% Lower ($ per MWh)	Original Power Procurement Cost ($ per MWh)	With Power Procurement Cost 30% Lower ($ per MWh)	With Power Procurement Cost 40% Lower ($ per MWh)	Original Power Procurement Cost ($ per MWh)	With Power Procurement Cost 30% Lower ($ per MWh)	With Power Procurement Cost 40% Lower ($ per MWh)
2020	66.81	46.76	40.08	74.54	52.18	44.72	85.91	60.14	51.55
2021	67.73	47.41	40.64	74.81	52.37	44.89	86.40	60.48	51.84
2022	67.32	47.13	40.39	73.55	51.48	44.13	84.98	59.49	50.99
2023	68.38	47.87	41.03	74.33	52.03	44.60	86.82	60.78	52.09
2024	67.98	47.59	40.79	72.80	50.96	43.68	84.62	59.23	50.77
2025	67.68	47.37	40.61	71.73	50.21	43.04	83.64	58.55	50.19
2026	68.31	47.82	40.98	71.69	50.18	43.01	84.11	58.88	50.47
2027	68.36	47.85	41.01	70.93	49.65	42.56	83.53	58.47	50.12
2028	68.83	48.18	41.30	70.56	49.39	42.34	83.29	58.30	49.97
2029	68.31	47.82	40.99	69.18	48.43	41.51	82.03	57.42	49.22
2030	68.64	48.05	41.18	68.64	48.05	41.18	81.38	56.97	48.83

Tables 72 through 77 present the average generation rate comparisons between the CCA and PG&E and SCE for the 30% decrease in power procurement cost and 40% decrease in power procurement cost cases for the AWG Jurisdictions renewable energy content scenarios.

As shown in Tables 72, 73, and 74, the 30% decrease in power procurement costs results in CCA generation rate proxies that are still not below both PG&E and SCE. While competitive against PG&E for the RPS Equivalent scenario (as shown in Table 72), CCA rates remain higher than PG&E for all years for the Middle of the Road and Aggressive scenarios (as shown in Tables 73 and 74, respectively). CCA rates also remain higher than SCE for all years for all scenarios.

Table 72 Generation Rate Comparisons, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario with Power Procurement Costs Decreased 30%

	2022		2023		2024		2025		2026	
Rate Class	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**
Agriculture	0.0941	0.0742	0.0941	0.0753	0.0941	0.0749	0.0941	0.0747	0.0941	0.0754
Commercial/Industrial Small <200kW	0.0949	0.1049	0.0949	0.1065	0.0949	0.1059	0.0949	0.1055	0.0949	0.1065
Commercial/Industrial Medium 200<500 kW	0.0956	0.1097	0.0956	0.1113	0.0956	0.1107	0.0956	0.1103	0.0956	0.1114
Commercial/Industrial Large 500<1000 kW	0.0911	0.1107	0.0911	0.1124	0.0911	0.1118	0.0911	0.1114	0.0911	0.1124
Residential	0.0986	0.1003	0.0986	0.1018	0.0986	0.1013	0.0986	0.1009	0.0986	0.1018
Residential CARE	0.0919	0.0936	0.0919	0.0950	0.0919	0.0945	0.0919	0.0941	0.0919	0.0950
Residential Solar Choice	0.1486	0.1265	0.1486	0.1284	0.1486	0.1277	0.1486	0.1272	0.1486	0.1284
Weighted Average	**0.0957**	**0.0961**	**0.0957**	**0.0975**	**0.0957**	**0.0970**	**0.0957**	**0.0967**	**0.0957**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**-0.37%**		**-1.84%**		**-1.31%**		**-0.96%**		**-1.88%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.0815	0.0543	0.0815	0.0551	0.0815	0.0548	0.0815	0.0547	0.0815	0.0552
Commercial/Industrial Small <200kW	0.0837	0.0922	0.0837	0.0936	0.0837	0.0931	0.0837	0.0927	0.0837	0.0936
Commercial/Industrial Medium 200<500 kW	0.0829	0.0837	0.0829	0.0850	0.0829	0.0845	0.0829	0.0842	0.0829	0.0850
Commercial/Industrial Large 500<1000 kW	0.0821	0.0777	0.0821	0.0789	0.0821	0.0785	0.0821	0.0782	0.0821	0.0789
Residential	0.0764	0.0712	0.0764	0.0723	0.0764	0.0719	0.0764	0.0716	0.0764	0.0723
Residential CARE	0.0688	0.0635	0.0688	0.0645	0.0688	0.0641	0.0688	0.0639	0.0688	0.0645
Residential Green Tariff	0.0964	0.1127	0.0964	0.1144	0.0964	0.1138	0.0964	0.1134	0.0964	0.1144
Weighted Average	**0.0799**	**0.0776**	**0.0799**	**0.0788**	**0.0799**	**0.0784**	**0.0799**	**0.0781**	**0.0799**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**2.91%**		**1.40%**		**1.94%**		**2.31%**		**1.36%**

Table 73 Generation Rate Comparisons, AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario with Power Procurement Costs Decreased 30%

	2022		2023		2024		2025		2026	
Rate Class	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**
Agriculture	0.0988	0.0742	0.0988	0.0753	0.0988	0.0749	0.0988	0.0747	0.0988	0.0754
Commercial/Industrial Small <200kW	0.0996	0.1049	0.0996	0.1065	0.0996	0.1059	0.0996	0.1055	0.0996	0.1065
Commercial/Industrial Medium 200<500 kW	0.1003	0.1097	0.1003	0.1113	0.1003	0.1107	0.1003	0.1103	0.1003	0.1114
Commercial/Industrial Large 500<1000 kW	0.0958	0.1107	0.0958	0.1124	0.0958	0.1118	0.0958	0.1114	0.0958	0.1124
Residential	0.1033	0.1003	0.1033	0.1018	0.1033	0.1013	0.1033	0.1009	0.1033	0.1018
Residential CARE	0.0966	0.0936	0.0966	0.0950	0.0966	0.0945	0.0966	0.0941	0.0966	0.0950
Residential Solar Choice	0.1533	0.1265	0.1533	0.1284	0.1533	0.1277	0.1533	0.1272	0.1533	0.1284
Weighted Average	**0.1004**	**0.0961**	**0.1004**	**0.0975**	**0.1004**	**0.0970**	**0.1004**	**0.0967**	**0.1004**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**4.51%**		**2.97%**		**3.52%**		**3.89%**		**2.93%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.0862	0.0543	0.0862	0.0551	0.0862	0.0548	0.0862	0.0547	0.0862	0.0552
Commercial/Industrial Small <200kW	0.0883	0.0922	0.0883	0.0936	0.0883	0.0931	0.0883	0.0927	0.0883	0.0936
Commercial/Industrial Medium 200<500 kW	0.0876	0.0837	0.0876	0.0850	0.0876	0.0845	0.0876	0.0842	0.0876	0.0850
Commercial/Industrial Large 500<1000 kW	0.0868	0.0777	0.0868	0.0789	0.0868	0.0785	0.0868	0.0782	0.0868	0.0789
Residential	0.0812	0.0712	0.0812	0.0723	0.0812	0.0719	0.0812	0.0716	0.0812	0.0723
Residential CARE	0.0736	0.0635	0.0736	0.0645	0.0736	0.0641	0.0736	0.0639	0.0736	0.0645
Residential Green Tariff	0.0912	0.1127	0.0912	0.1144	0.0912	0.1138	0.0912	0.1134	0.0912	0.1144
Weighted Average	**0.0846**	**0.0776**	**0.0846**	**0.0788**	**0.0846**	**0.0784**	**0.0846**	**0.0781**	**0.0846**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**8.91%**		**7.31%**		**7.88%**		**8.27%**		**7.26%**

Table 74 Generation Rate Comparisons, AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario with Power Procurement Costs Decreased 30%

	2022		2023		2024		2025		2026	
Rate Class	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**
Agriculture	0.1087	0.0742	0.1087	0.0753	0.1087	0.0749	0.1087	0.0747	0.1087	0.0754
Commercial/Industrial Small <200kW	0.1095	0.1049	0.1095	0.1065	0.1095	0.1059	0.1095	0.1055	0.1095	0.1065
Commercial/Industrial Medium 200<500 kW	0.1101	0.1097	0.1101	0.1113	0.1101	0.1107	0.1101	0.1103	0.1101	0.1114
Commercial/Industrial Large 500<1000 kW	0.1057	0.1107	0.1057	0.1124	0.1057	0.1118	0.1057	0.1114	0.1057	0.1124
Residential	0.1131	0.1003	0.1131	0.1018	0.1131	0.1013	0.1131	0.1009	0.1131	0.1018
Residential CARE	0.1064	0.0936	0.1064	0.0950	0.1064	0.0945	0.1064	0.0941	0.1064	0.0950
Residential Solar Choice	0.1531	0.1265	0.1531	0.1284	0.1531	0.1277	0.1531	0.1272	0.1531	0.1284
Weighted Average	**0.1102**	**0.0961**	**0.1102**	**0.0975**	**0.1102**	**0.0970**	**0.1102**	**0.0967**	**0.1102**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**14.67%**		**12.98%**		**13.59%**		**14.00%**		**12.94%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.0961	0.0543	0.0961	0.0551	0.0961	0.0548	0.0961	0.0547	0.0961	0.0552
Commercial/Industrial Small <200kW	0.0982	0.0922	0.0982	0.0936	0.0982	0.0931	0.0982	0.0927	0.0982	0.0936
Commercial/Industrial Medium 200<500 kW	0.0975	0.0837	0.0975	0.0850	0.0975	0.0845	0.0975	0.0842	0.0975	0.0850
Commercial/Industrial Large 500<1000 kW	0.0967	0.0777	0.0967	0.0789	0.0967	0.0785	0.0967	0.0782	0.0967	0.0789
Residential	0.0910	0.0712	0.0910	0.0723	0.0910	0.0719	0.0910	0.0716	0.0910	0.0723
Residential CARE	0.0835	0.0635	0.0835	0.0645	0.0835	0.0641	0.0835	0.0639	0.0835	0.0645
Residential Green Tariff	0.0910	0.1127	0.0910	0.1144	0.0910	0.1138	0.0910	0.1134	0.0910	0.1144
Weighted Average	**0.0943**	**0.0776**	**0.0943**	**0.0788**	**0.0943**	**0.0784**	**0.0943**	**0.0781**	**0.0943**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**21.52%**		**19.73%**		**20.37%**		**20.80%**		**19.68%**

Tables 75 and 76 show that CCA generation rate proxies become competitive against both PG&E and SCE once power procurement costs are decreased for the CCA by 40% for the RPS Equivalent and Middle of the Road scenarios. Table 77 shows that CCA rate proxies are still higher than PG&E and SCE under the Aggressive scenario, even with a 40% reduction in power procurement costs.

Table 75 Generation Rate Comparisons, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario with Power Procurement Costs Decreased 40%

Rate Class	2022		2023		2024		2025		2026	
	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates
Agriculture	0.0864	0.0742	0.0864	0.0753	0.0864	0.0749	0.0864	0.0747	0.0864	0.0754
Commercial/Industrial Small <200kW	0.0872	0.1049	0.0872	0.1065	0.0872	0.1059	0.0872	0.1055	0.0872	0.1065
Commercial/Industrial Medium 200<500 kW	0.0878	0.1097	0.0878	0.1113	0.0878	0.1107	0.0878	0.1103	0.0878	0.1114
Commercial/Industrial Large 500<1000 kW	0.0833	0.1107	0.0833	0.1124	0.0833	0.1118	0.0833	0.1114	0.0833	0.1124
Residential	0.0908	0.1003	0.0908	0.1018	0.0908	0.1013	0.0908	0.1009	0.0908	0.1018
Residential CARE	0.0841	0.0936	0.0841	0.0950	0.0841	0.0945	0.0841	0.0941	0.0841	0.0950
Residential Solar Choice	0.1408	0.1265	0.1408	0.1284	0.1408	0.1277	0.1408	0.1272	0.1408	0.1284
Weighted Average	**0.0880**	**0.0961**	**0.0880**	**0.0975**	**0.0880**	**0.0970**	**0.0880**	**0.0967**	**0.0880**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**-8.46%**		**-9.81%**		**-9.33%**		**-9.00%**		**-9.85%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.0736	0.0543	0.0736	0.0551	0.0736	0.0548	0.0736	0.0547	0.0736	0.0552
Commercial/Industrial Small <200kW	0.0758	0.0922	0.0758	0.0936	0.0758	0.0931	0.0758	0.0927	0.0758	0.0936
Commercial/Industrial Medium 200<500 kW	0.0750	0.0837	0.0750	0.0850	0.0750	0.0845	0.0750	0.0842	0.0750	0.0850
Commercial/Industrial Large 500<1000 kW	0.0743	0.0777	0.0743	0.0789	0.0743	0.0785	0.0743	0.0782	0.0743	0.0789
Residential	0.0686	0.0712	0.0686	0.0723	0.0686	0.0719	0.0686	0.0716	0.0686	0.0723
Residential CARE	0.0610	0.0635	0.0610	0.0645	0.0610	0.0641	0.0610	0.0639	0.0610	0.0645
Residential Green Tariff	0.0786	0.1127	0.0786	0.1144	0.0786	0.1138	0.0786	0.1134	0.0786	0.1144
Weighted Average	**0.0720**	**0.0776**	**0.0720**	**0.0788**	**0.0720**	**0.0784**	**0.0720**	**0.0781**	**0.0720**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**-7.30%**		**-8.66%**		**-8.17%**		**-7.84%**		**-8.70%**

Table 76 Generation Rate Comparisons, AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario with Power Procurement Costs Decreased 40%

Rate Class	2022		2023		2024		2025		2026	
	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates
Agriculture	0.0904	0.0742	0.0904	0.0753	0.0904	0.0749	0.0904	0.0747	0.0904	0.0754
Commercial/Industrial Small <200kW	0.0912	0.1049	0.0912	0.1065	0.0912	0.1059	0.0912	0.1055	0.0912	0.1065
Commercial/Industrial Medium 200<500 kW	0.0918	0.1097	0.0918	0.1113	0.0918	0.1107	0.0918	0.1103	0.0918	0.1114
Commercial/Industrial Large 500<1000 kW	0.0874	0.1107	0.0874	0.1124	0.0874	0.1118	0.0874	0.1114	0.0874	0.1124
Residential	0.0948	0.1003	0.0948	0.1018	0.0948	0.1013	0.0948	0.1009	0.0948	0.1018
Residential CARE	0.0881	0.0936	0.0881	0.0950	0.0881	0.0945	0.0881	0.0941	0.0881	0.0950
Residential Solar Choice	0.1348	0.1265	0.1348	0.1284	0.1348	0.1277	0.1348	0.1272	0.1348	0.1284
Weighted Average	**0.0919**	**0.0961**	**0.0919**	**0.0975**	**0.0919**	**0.0970**	**0.0919**	**0.0967**	**0.0919**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**-4.34%**		**-5.75%**		**-5.24%**		**-4.90%**		**-5.79%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.0777	0.0543	0.0777	0.0551	0.0777	0.0548	0.0777	0.0547	0.0777	0.0552
Commercial/Industrial Small <200kW	0.0799	0.0922	0.0799	0.0936	0.0799	0.0931	0.0799	0.0927	0.0799	0.0936
Commercial/Industrial Medium 200<500 kW	0.0791	0.0837	0.0791	0.0850	0.0791	0.0845	0.0791	0.0842	0.0791	0.0850
Commercial/Industrial Large 500<1000 kW	0.0783	0.0777	0.0783	0.0789	0.0783	0.0785	0.0783	0.0782	0.0783	0.0789
Residential	0.0727	0.0712	0.0727	0.0723	0.0727	0.0719	0.0727	0.0716	0.0727	0.0723
Residential CARE	0.0650	0.0635	0.0650	0.0645	0.0650	0.0641	0.0650	0.0639	0.0650	0.0645
Residential Green Tariff	0.0827	0.1127	0.0827	0.1144	0.0827	0.1138	0.0827	0.1134	0.0827	0.1144
Weighted Average	**0.0761**	**0.0776**	**0.0761**	**0.0788**	**0.0761**	**0.0784**	**0.0761**	**0.0781**	**0.0761**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**-2.01%**		**-3.46%**		**-2.94%**		**-2.59%**		**-3.50%**

Table 77 Generation Rate Comparisons, AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario with Power Procurement Costs Decreased 40%

Rate Class	2022		2023		2024		2025		2026	
	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates
Agriculture	0.0988	0.0742	0.0988	0.0753	0.0988	0.0749	0.0988	0.0747	0.0988	0.0754
Commercial/Industrial Small <200kW	0.0996	0.1049	0.0996	0.1065	0.0996	0.1059	0.0996	0.1055	0.0996	0.1065
Commercial/Industrial Medium 200<500 kW	0.1002	0.1097	0.1002	0.1113	0.1002	0.1107	0.1002	0.1103	0.1002	0.1114
Commercial/Industrial Large 500<1000 kW	0.0958	0.1107	0.0958	0.1124	0.0958	0.1118	0.0958	0.1114	0.0958	0.1124
Residential	0.1032	0.1003	0.1032	0.1018	0.1032	0.1013	0.1032	0.1009	0.1032	0.1018
Residential CARE	0.0965	0.0936	0.0965	0.0950	0.0965	0.0945	0.0965	0.0941	0.0965	0.0950
Residential Solar Choice	0.1432	0.1265	0.1432	0.1284	0.1432	0.1277	0.1432	0.1272	0.1432	0.1284
Weighted Average	**0.1003**	**0.0961**	**0.1003**	**0.0975**	**0.1003**	**0.0970**	**0.1003**	**0.0967**	**0.1003**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**4.40%**		**2.86%**		**3.41%**		**3.78%**		**2.82%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.0861	0.0543	0.0861	0.0551	0.0861	0.0548	0.0861	0.0547	0.0861	0.0552
Commercial/Industrial Small <200kW	0.0883	0.0922	0.0883	0.0936	0.0883	0.0931	0.0883	0.0927	0.0883	0.0936
Commercial/Industrial Medium 200<500 kW	0.0875	0.0837	0.0875	0.0850	0.0875	0.0845	0.0875	0.0842	0.0875	0.0850
Commercial/Industrial Large 500<1000 kW	0.0868	0.0777	0.0868	0.0789	0.0868	0.0785	0.0868	0.0782	0.0868	0.0789
Residential	0.0811	0.0712	0.0811	0.0723	0.0811	0.0719	0.0811	0.0716	0.0811	0.0723
Residential CARE	0.0735	0.0635	0.0735	0.0645	0.0735	0.0641	0.0735	0.0639	0.0735	0.0645
Residential Green Tariff	0.0811	0.1127	0.0811	0.1144	0.0811	0.1138	0.0811	0.1134	0.0811	0.1144
Weighted Average	**0.0844**	**0.0776**	**0.0844**	**0.0788**	**0.0844**	**0.0784**	**0.0844**	**0.0781**	**0.0844**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**8.73%**		**7.13%**		**7.70%**		**8.09%**		**7.08%**

E.2.b Staffing Cost Sensitivity

Table 78 shows the total staffing costs between the AWG Jurisdictions participation scenarios and the 70% decrease in staffing costs sensitivity case.

Table 78 Test Year Staffing Costs, AWG Jurisdictions, All Renewable Energy Content Scenarios with Staffing Costs Decreased 70%

Line	Description	Number of Positions	Annual Salary and Benefits Costs, AWG Jurisdictions Scenarios ($)	Annual Salary and Benefits Costs with 70% Decrease ($)
	Executive Management Positions:			
1	General Manager	1	350,868	105,260
2	Assistant General Manager	1	241,563	72,469
3	Chief Financial Officer	1	301,680	90,504
4	Customer Service Manager	1	241,563	72,469
5	Human Resources Manager	1	241,563	72,469
6	Attorney	1	334,472	100,342
7	Total Executive Management Positions:	6	1,711,709	513,513
	Other/Departmental Management Positions			
8	Accounting and Budget Manager	1	163,957	49,187
9	Rates and Regulatory Affairs Manager	1	226,260	67,878
10	Customer Information and Billing Manager	1	226,260	67,878
11	Key Accounts Manager	1	226,260	67,878
12	DSM Program Manager	1	174,887	52,466
13	Communications and Public Relations Manager	1	174,887	52,466
14	Power Supply and Planning Manager	1	213,144	63,943
15	Information Technology Manager	1	226,260	67,878
16	Procurement and Contracts Manager	1	163,957	49,187
17	Total Other/Departmental Management Positions	9	1,795,873	538,762
	Analyst, Technical, Engineering Positions			
18	Contracts Analyst	1	128,979	38,694
19	Accounting and Budget Analyst	2	257,959	77,388
20	Rates and Regulatory Affairs Analyst	1	128,979	38,694
21	Power Supply Analyst	2	277,633	83,290
22	DSM Analyst	2	277,633	83,290
23	Total Analyst, Technical, Engineering Positions	8	1,071,184	321,355
	Administrative, Customer Service, and Other Positions			
24	Executive Administrative Assistant	3	341,030	102,309
25	Administrative Assistant	4	314,797	94,439
26	Customer Service Representative	4	314,797	94,439
27	Key Account Representative	7	994,671	298,401
28	Communications Specialist	1	122,421	36,726
29	IT Specialist	2	244,842	73,453
30	Human Resources Specialist	1	142,096	42,629
31	Total Administrative, Customer Service, and Other Positions	22	2,474,654	742,396
32	**Total, All Positions**	**45**	**7,053,421**	**2,116,026**

Tables 79 through 81 depict the rate comparisons under the 70% decrease in staffing costs case for the AWG Jurisdictions RPS Equivalent, Middle of the Road, and Aggressive scenarios, respectively. Even with this large reduction in staffing costs, the CCA generation rate proxies under the AWG Jurisdictions scenarios are not competitive with PG&E and SCE. CCA customers are forecast to pay a premium for all rate classes for all years.

Table 79 Generation Rate Comparisons AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario with Staffing Costs Decreased 70%

Rate Class	2022		2023		2024		2025		2026	
	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates
Agriculture	0.1164	0.0742	0.1164	0.0753	0.1164	0.0749	0.1164	0.0747	0.1164	0.0754
Commercial/Industrial Small <200kW	0.1172	0.1049	0.1172	0.1065	0.1172	0.1059	0.1172	0.1055	0.1172	0.1065
Commercial/Industrial Medium 200<500 kW	0.1178	0.1097	0.1178	0.1113	0.1178	0.1107	0.1178	0.1103	0.1178	0.1114
Commercial/Industrial Large 500<1000 kW	0.1133	0.1107	0.1133	0.1124	0.1133	0.1118	0.1133	0.1114	0.1133	0.1124
Residential	0.1208	0.1003	0.1208	0.1018	0.1208	0.1013	0.1208	0.1009	0.1208	0.1018
Residential CARE	0.1141	0.0936	0.1141	0.0950	0.1141	0.0945	0.1141	0.0941	0.1141	0.0950
Residential Solar Choice	0.1908	0.1265	0.1908	0.1284	0.1908	0.1277	0.1908	0.1272	0.1908	0.1284
Weighted Average	**0.1181**	**0.0961**	**0.1181**	**0.0975**	**0.1181**	**0.0970**	**0.1181**	**0.0967**	**0.1181**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**22.88%**		**21.07%**		**21.72%**		**22.16%**		**21.02%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1038	0.0543	0.1038	0.0551	0.1038	0.0548	0.1038	0.0547	0.1038	0.0552
Commercial/Industrial Small <200kW	0.1060	0.0922	0.1060	0.0936	0.1060	0.0931	0.1060	0.0927	0.1060	0.0936
Commercial/Industrial Medium 200<500 kW	0.1052	0.0837	0.1052	0.0850	0.1052	0.0845	0.1052	0.0842	0.1052	0.0850
Commercial/Industrial Large 500<1000 kW	0.1045	0.0777	0.1045	0.0789	0.1045	0.0785	0.1045	0.0782	0.1045	0.0789
Residential	0.0988	0.0712	0.0988	0.0723	0.0988	0.0719	0.0988	0.0716	0.0988	0.0723
Residential CARE	0.0912	0.0635	0.0912	0.0645	0.0912	0.0641	0.0912	0.0639	0.0912	0.0645
Residential Green Tariff	0.1188	0.1127	0.1188	0.1144	0.1188	0.1138	0.1188	0.1134	0.1188	0.1144
Weighted Average	**0.1023**	**0.0776**	**0.1023**	**0.0788**	**0.1023**	**0.0784**	**0.1023**	**0.0781**	**0.1023**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**31.70%**		**29.76%**		**30.45%**		**30.93%**		**29.71%**

Table 80 Generation Rate Comparisons AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario with Staffing Costs Decreased 70%

Rate Class	2022		2023		2024		2025		2026	
	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates	CCA Rates	PG&E Rates
Agriculture	0.1230	0.0742	0.1230	0.0753	0.1230	0.0749	0.1230	0.0747	0.1230	0.0754
Commercial/Industrial Small <200kW	0.1238	0.1049	0.1238	0.1065	0.1238	0.1059	0.1238	0.1055	0.1238	0.1065
Commercial/Industrial Medium 200<500 kW	0.1245	0.1097	0.1245	0.1113	0.1245	0.1107	0.1245	0.1103	0.1245	0.1114
Commercial/Industrial Large 500<1000 kW	0.1200	0.1107	0.1200	0.1124	0.1200	0.1118	0.1200	0.1114	0.1200	0.1124
Residential	0.1275	0.1003	0.1275	0.1018	0.1275	0.1013	0.1275	0.1009	0.1275	0.1018
Residential CARE	0.1208	0.0936	0.1208	0.0950	0.1208	0.0945	0.1208	0.0941	0.1208	0.0950
Residential Solar Choice	0.1975	0.1265	0.1975	0.1284	0.1975	0.1277	0.1975	0.1272	0.1975	0.1284
Weighted Average	**0.1248**	**0.0961**	**0.1248**	**0.0975**	**0.1248**	**0.0970**	**0.1248**	**0.0967**	**0.1248**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**29.84%**		**27.93%**		**28.62%**		**29.08%**		**27.88%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1106	0.0543	0.1106	0.0551	0.1106	0.0548	0.1106	0.0547	0.1106	0.0552
Commercial/Industrial Small <200kW	0.1127	0.0922	0.1127	0.0936	0.1127	0.0931	0.1127	0.0927	0.1127	0.0936
Commercial/Industrial Medium 200<500 kW	0.1120	0.0837	0.1120	0.0850	0.1120	0.0845	0.1120	0.0842	0.1120	0.0850
Commercial/Industrial Large 500<1000 kW	0.1112	0.0777	0.1112	0.0789	0.1112	0.0785	0.1112	0.0782	0.1112	0.0789
Residential	0.1056	0.0712	0.1056	0.0723	0.1056	0.0719	0.1056	0.0716	0.1056	0.0723
Residential CARE	0.0979	0.0635	0.0979	0.0645	0.0979	0.0641	0.0979	0.0639	0.0979	0.0645
Residential Green Tariff	0.1256	0.1127	0.1256	0.1144	0.1256	0.1138	0.1256	0.1134	0.1256	0.1144
Weighted Average	**0.1091**	**0.0776**	**0.1091**	**0.0788**	**0.1091**	**0.0784**	**0.1091**	**0.0781**	**0.1091**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**40.46%**		**38.39%**		**39.13%**		**39.63%**		**38.33%**

Table 81 Generation Rate Comparisons AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario with Staffing Costs Decreased 70%

Rate Class	2022 CCA Rates	2022 PG&E Rates	2023 CCA Rates	2023 PG&E Rates	2024 CCA Rates	2024 PG&E Rates	2025 CCA Rates	2025 PG&E Rates	2026 CCA Rates	2026 PG&E Rates
Agriculture	0.1370	0.0742	0.1370	0.0753	0.1370	0.0749	0.1370	0.0747	0.1370	0.0754
Commercial/Industrial Small <200kW	0.1378	0.1049	0.1378	0.1065	0.1378	0.1059	0.1378	0.1055	0.1378	0.1065
Commercial/Industrial Medium 200<500 kW	0.1385	0.1097	0.1385	0.1113	0.1385	0.1107	0.1385	0.1103	0.1385	0.1114
Commercial/Industrial Large 500<1000 kW	0.1340	0.1107	0.1340	0.1124	0.1340	0.1118	0.1340	0.1114	0.1340	0.1124
Residential	0.1415	0.1003	0.1415	0.1018	0.1415	0.1013	0.1415	0.1009	0.1415	0.1018
Residential CARE	0.1348	0.0936	0.1348	0.0950	0.1348	0.0945	0.1348	0.0941	0.1348	0.0950
Residential Solar Choice	0.2015	0.1265	0.2015	0.1284	0.2015	0.1277	0.2015	0.1272	0.2015	0.1284
Weighted Average	**0.1387**	**0.0961**	**0.1387**	**0.0975**	**0.1387**	**0.0970**	**0.1387**	**0.0967**	**0.1387**	**0.0976**
CCA Rate Premium/ (CCA Savings)		**44.33%**		**42.21%**		**42.97%**		**43.48%**		**42.15%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1246	0.0543	0.1246	0.0551	0.1246	0.0548	0.1246	0.0547	0.1246	0.0552
Commercial/Industrial Small <200kW	0.1268	0.0922	0.1268	0.0936	0.1268	0.0931	0.1268	0.0927	0.1268	0.0936
Commercial/Industrial Medium 200<500 kW	0.1261	0.0837	0.1261	0.0850	0.1261	0.0845	0.1261	0.0842	0.1261	0.0850
Commercial/Industrial Large 500<1000 kW	0.1253	0.0777	0.1253	0.0789	0.1253	0.0785	0.1253	0.0782	0.1253	0.0789
Residential	0.1196	0.0712	0.1196	0.0723	0.1196	0.0719	0.1196	0.0716	0.1196	0.0723
Residential CARE	0.1120	0.0635	0.1120	0.0645	0.1120	0.0641	0.1120	0.0639	0.1120	0.0645
Residential Green Tariff	0.1296	0.1127	0.1296	0.1144	0.1296	0.1138	0.1296	0.1134	0.1296	0.1144
Weighted Average	**0.1230**	**0.0776**	**0.1230**	**0.0788**	**0.1230**	**0.0784**	**0.1230**	**0.0781**	**0.1230**	**0.0788**
CCA Rate Premium/ (CCA Savings)		**58.43%**		**56.10%**		**56.93%**		**57.50%**		**56.03%**

E.2.c PG&E and SCE Rate Escalation Sensitivity

Table 82 depicts the PG&E and SCE annual generation rate escalation assumed within the Study and with a 4.0% increase. The Study's escalation rates were applied to all classes for both IOUs and were used within all participation and renewable energy content scenarios. As with the power procurement cost and staffing cost sensitivities, the rate escalation sensitivity was evaluated against the AWG Jurisdictions scenarios.

Table 82 Study's Assumed PG&E and SCE Generation Rate Escalation and with a 4.0% Increase

Year	Study's Assumed Rate Escalation	With IOU Rates Escalated at Additional 4.0%
2020	0.00%	4.00%
2021	0.85%	4.85%
2022	-0.49%	3.51%
2023	1.50%	5.50%
2024	-0.53%	3.47%
2025	-0.36%	3.64%
2026	0.94%	4.94%

Tables 83 through 85 depict the generation rate comparison results of the 4.0% increase in annual escalation of PG&E and SCE rates for each renewable energy content scenario. This increased rates escalation results in CCA rate proxies being more competitive compared to the original escalation used.

For the RPS Equivalent scenario, compared to PG&E, CCA average generation rate proxies are less than PG&E beginning in year 2023; savings continue to increase through 2026. CCA average generation rate proxies are still higher than SCE through 2024, and then become lower in 2026. For the Middle of the Road scenario, compared to PG&E, CCA average generation rate proxies are less than PG&E beginning in year 2024; savings continue to increase in years 2025 and 2026. CCA average generation rate proxies still are higher than SCE rates through year 2025, and then become lower than SCE in 2026. Under the Aggressive scenario, CCA average generation rate proxies remain higher than PG&E and SCE through 2026.

Table 83 Generation Rate Comparisons, AWG Jurisdictions RPS Equivalent Renewable Energy Content Scenario with IOU Annual Rates Escalation Increased 4.0%

	2022		2023		2024		2025		2026	
Rate Class	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**
Agriculture	0.1175	0.0903	0.1175	0.0952	0.1175	0.0985	0.1175	0.1021	0.1175	0.1072
Commercial/Industrial Small <200kW	0.1183	0.1276	0.1183	0.1346	0.1183	0.1393	0.1183	0.1443	0.1183	0.1515
Commercial/Industrial Medium 200<500 kW	0.1190	0.1334	0.1190	0.1408	0.1190	0.1456	0.1190	0.1509	0.1190	0.1584
Commercial/Industrial Large 500<1000 kW	0.1145	0.1347	0.1145	0.1421	0.1145	0.1470	0.1145	0.1524	0.1145	0.1599
Residential	0.1220	0.1220	0.1220	0.1287	0.1220	0.1332	0.1220	0.1380	0.1220	0.1448
Residential CARE	0.1152	0.1138	0.1152	0.1201	0.1152	0.1243	0.1152	0.1288	0.1152	0.1351
Residential Solar Choice	0.1920	0.1539	0.1920	0.1623	0.1920	0.1680	0.1920	0.1741	0.1920	0.1827
Weighted Average	**0.1193**	**0.1169**	**0.1193**	**0.1233**	**0.1193**	**0.1276**	**0.1193**	**0.1323**	**0.1193**	**0.1388**
CCA Rate Premium/ (CCA Savings)		**2.01%**		**-3.30%**		**-6.54%**		**-9.82%**		**-14.07%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1050	0.0661	0.1050	0.0697	0.1050	0.0721	0.1050	0.0748	0.1050	0.0785
Commercial/Industrial Small <200kW	0.1072	0.1122	0.1072	0.1183	0.1072	0.1224	0.1072	0.1269	0.1072	0.1331
Commercial/Industrial Medium 200<500 kW	0.1064	0.1018	0.1064	0.1074	0.1064	0.1112	0.1064	0.1152	0.1064	0.1209
Commercial/Industrial Large 500<1000 kW	0.1057	0.0946	0.1057	0.0998	0.1057	0.1032	0.1057	0.1070	0.1057	0.1123
Residential	0.0999	0.0866	0.0999	0.0914	0.0999	0.0945	0.0999	0.0980	0.0999	0.1028
Residential CARE	0.0924	0.0773	0.0924	0.0815	0.0924	0.0844	0.0924	0.0874	0.0924	0.0918
Residential Green Tariff	0.1199	0.1371	0.1199	0.1446	0.1199	0.1496	0.1199	0.1551	0.1199	0.1627
Weighted Average	**0.1034**	**0.0944**	**0.1034**	**0.0996**	**0.1034**	**0.1031**	**0.1034**	**0.1068**	**0.1034**	**0.1121**
CCA Rate Premium/ (CCA Savings)		**9.52%**		**3.81%**		**0.33%**		**-3.19%**		**-7.75%**

Table 84 Generation Rate Comparisons, AWG Jurisdictions Middle of the Road (50%) Renewable Energy Content Scenario with IOU Annual Rates Escalation Increased 4.0%

	2022		2023		2024		2025		2026	
Rate Class	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**
Agriculture	0.1242	0.0903	0.1242	0.0952	0.1242	0.0985	0.1242	0.1021	0.1242	0.1072
Commercial/Industrial Small <200kW	0.1250	0.1276	0.1250	0.1346	0.1250	0.1393	0.1250	0.1443	0.1250	0.1515
Commercial/Industrial Medium 200<500 kW	0.1257	0.1334	0.1257	0.1408	0.1257	0.1456	0.1257	0.1509	0.1257	0.1584
Commercial/Industrial Large 500<1000 kW	0.1212	0.1347	0.1212	0.1421	0.1212	0.1470	0.1212	0.1524	0.1212	0.1599
Residential	0.1287	0.1220	0.1287	0.1287	0.1287	0.1332	0.1287	0.1380	0.1287	0.1448
Residential CARE	0.1219	0.1138	0.1219	0.1201	0.1219	0.1243	0.1219	0.1288	0.1219	0.1351
Residential Solar Choice	0.1987	0.1539	0.1987	0.1623	0.1987	0.1680	0.1987	0.1741	0.1987	0.1827
Weighted Average	**0.1260**	**0.1169**	**0.1260**	**0.1233**	**0.1260**	**0.1276**	**0.1260**	**0.1323**	**0.1260**	**0.1388**
CCA Rate Premium/ (CCA Savings)		**7.74%**		**2.13%**		**-1.30%**		**-4.76%**		**-9.25%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1117	0.0661	0.1117	0.0697	0.1117	0.0721	0.1117	0.0748	0.1117	0.0785
Commercial/Industrial Small <200kW	0.1139	0.1122	0.1139	0.1183	0.1139	0.1224	0.1139	0.1269	0.1139	0.1331
Commercial/Industrial Medium 200<500 kW	0.1132	0.1018	0.1132	0.1074	0.1132	0.1112	0.1132	0.1152	0.1132	0.1209
Commercial/Industrial Large 500<1000 kW	0.1124	0.0946	0.1124	0.0998	0.1124	0.1032	0.1124	0.1070	0.1124	0.1123
Residential	0.1066	0.0866	0.1066	0.0914	0.1066	0.0945	0.1066	0.0980	0.1066	0.1028
Residential CARE	0.0991	0.0773	0.0991	0.0815	0.0991	0.0844	0.0991	0.0874	0.0991	0.0918
Residential Green Tariff	0.1266	0.1371	0.1266	0.1446	0.1266	0.1496	0.1266	0.1551	0.1266	0.1627
Weighted Average	**0.1102**	**0.0944**	**0.1102**	**0.0996**	**0.1102**	**0.1031**	**0.1102**	**0.1068**	**0.1102**	**0.1121**
CCA Rate Premium/ (CCA Savings)		**16.63%**		**10.55%**		**6.84%**		**3.09%**		**-1.76%**

Table 85 Generation Rate Comparisons, AWG Jurisdictions Aggressive (75%) Renewable Energy Content Scenario with IOU Annual Rates Escalation Increased 4.0%

	2022		2023		2024		2025		2026	
Rate Class	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**	**CCA Rates**	**PG&E Rates**
Agriculture	0.1382	0.0903	0.1382	0.0952	0.1382	0.0985	0.1382	0.1021	0.1382	0.1072
Commercial/Industrial Small <200kW	0.1390	0.1276	0.1390	0.1346	0.1390	0.1393	0.1390	0.1443	0.1390	0.1515
Commercial/Industrial Medium 200<500 kW	0.1397	0.1334	0.1397	0.1408	0.1397	0.1456	0.1397	0.1509	0.1397	0.1584
Commercial/Industrial Large 500<1000 kW	0.1352	0.1347	0.1352	0.1421	0.1352	0.1470	0.1352	0.1524	0.1352	0.1599
Residential	0.1426	0.1220	0.1426	0.1287	0.1426	0.1332	0.1426	0.1380	0.1426	0.1448
Residential CARE	0.1359	0.1138	0.1359	0.1201	0.1359	0.1243	0.1359	0.1288	0.1359	0.1351
Residential Solar Choice	0.2026	0.1539	0.2026	0.1623	0.2026	0.1680	0.2026	0.1741	0.2026	0.1827
Weighted Average	**0.1399**	**0.1169**	**0.1399**	**0.1233**	**0.1399**	**0.1276**	**0.1399**	**0.1323**	**0.1399**	**0.1388**
CCA Rate Premium/ (CCA Savings)		**19.65%**		**13.42%**		**9.62%**		**5.77%**		**0.79%**
Rate Class	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**	**CCA Rates**	**SCE Rates**
Agriculture	0.1258	0.0661	0.1258	0.0697	0.1258	0.0721	0.1258	0.0748	0.1258	0.0785
Commercial/Industrial Small <200kW	0.1280	0.1122	0.1280	0.1183	0.1280	0.1224	0.1280	0.1269	0.1280	0.1331
Commercial/Industrial Medium 200<500 kW	0.1272	0.1018	0.1272	0.1074	0.1272	0.1112	0.1272	0.1152	0.1272	0.1209
Commercial/Industrial Large 500<1000 kW	0.1265	0.0946	0.1265	0.0998	0.1265	0.1032	0.1265	0.1070	0.1265	0.1123
Residential	0.1208	0.0866	0.1208	0.0914	0.1208	0.0945	0.1208	0.0980	0.1208	0.1028
Residential CARE	0.1132	0.0773	0.1132	0.0815	0.1132	0.0844	0.1132	0.0874	0.1132	0.0918
Residential Green Tariff	0.1308	0.1371	0.1308	0.1446	0.1308	0.1496	0.1308	0.1551	0.1308	0.1627
Weighted Average	**0.1242**	**0.0944**	**0.1242**	**0.0996**	**0.1242**	**0.1031**	**0.1242**	**0.1068**	**0.1242**	**0.1121**
CCA Rate Premium/ (CCA Savings)		**31.48%**		**24.63%**		**20.45%**		**16.22%**		**10.75%**

F. Economic Impact Analysis

The preliminary results of the financial feasibility analysis indicate that the Central Coast Power CCA does not meet feasibility criteria and is not expected to generate revenues in excess of operating costs. This infeasible result suggests that a Central Coast Power CCA would not provide economic benefits to the region. However, if conditions change making a CCA viable, and the CCA is able to generate revenues in excess of its expenses, the CCA could reinvest these revenues in three ways that benefit the local economy:

- Lower customer rates,
- Build local generation or storage projects, and
- Expand or create customer DER programs.

The results in this Section II.F. Economic Impact Analysis are presented for illustrative purposes.

Had the Central Coast Power CCA met feasibility thresholds—which it did not—this section explores the economic development potential of the CCA. Establishing a CCA could hypothetically result in four levels of economic impact:

- **Customer bill savings.** If customers pay lower electricity bills due to lower CCA rates relative to the incumbent IOUs, these customers would have increased disposable income that could be used for local purchases that may support local businesses and stimulate increased sales tax revenues.
- **Local generation or storage projects.** If the CCA receives revenues in excess of its expenses, the CCA could reinvest those earnings to build out new local generation and storage projects, which would create temporary construction jobs and ongoing operations and maintenance (O&M) jobs. The salaries earned and purchases made locally could stimulate the local economy. .
- **CCA customer programs**. If the CCA receives revenues in excess of its expenses, the CCA could reinvest those earnings in the development or expansion of customer programs that increase financial incentives for customers who, for example, install DG PV, implement storage projects, purchase electric vehicles, or make energy efficiency upgrades.
- **Public health improvements.** If the CCA stimulates demand for new renewable energy generation projects that displace existing fossil fuel generating units, the resulting improvement in air quality could reduce the harmful health impacts of fossil fuel generation. This improved human health could lead to reduced healthcare expenditures and prolonged lifespans. However, the economic benefit of these health improvements will only accrue to the Tri-County Region if the air quality is improved locally through the decreased use of or retirement of fossil fuel power plants that are located in or contribute to air quality problems in the region.

This section focuses on the first two economic drivers: bill savings and local renewable energy projects. The remainder of this section provides: the rationale for quantifying these economic impacts; a description of the key assumptions and underlying methodology; and a summary of the results in terms of retail and construction spending, jobs, labor income, output and total value-added activity within the Tri-County Region in the Year 2026 (assumed for illustrative purposes).

F.1. Approach to Economic Impact Analysis

The two typical primary economic impacts of CCA implementation can be summarized as follows:

- Increased Disposable Income – Establishing a CCA could result in lower customer electric bills resulting in more disposable income. This money could be spent locally, leading to greater revenues for local businesses. These cost savings would subsequently lead to additional investment by individuals and businesses for personal or business purposes, resulting in increased employment for multiple sectors such as retail, construction, and manufacturing. IMPLAN Group LLC's (IMPLAN's) Input-Output Multiplier Model (I/O Model)[139] is typically used to quantify the expected economic impacts arising from lower energy bills for CCA customers. For the purpose of this economic impact analysis, potential economic benefits from disposable income are excluded due to estimated increase utility bill rates, indicating the CCA does not meeting feasibility thresholds.
- Local Investment in Renewable Energy Generation – CCAs typically obtain a higher percentage of their electricity portfolio from renewable resources, which typically leads to increased demand for renewable energy. Additionally, some CCAs desire to support local renewable energy generation. This demand for local renewable energy could lead to an increase in the manufacturing and installation of local DER and employment in the related manufacturing and construction sectors. For illustrative purposes, the NREL's Jobs and Economic Development Impact (JEDI)[140] model was used to quantify the economic impacts of such investment.

The potential for hypothetical future local investment in renewable energy generation in the Tri-County region is based on the following assumptions:

- None of the disposable income analyses for 24 scenarios (8 participation scenarios with 3 renewable content scenarios each) indicate that the CCA's operations could be expected to fund additional future renewables. However, hypothetical renewable energy project installations are evaluated for discussion purposes.
- The Tri-County Region could support up to a 10 MW solar project estimated to require between 60 to 70 acres of horizontal space (ground level or rooftop).
- Although a utility-scale solar opportunity would be feasible within the Tri-County Region, it has not been included in this evaluation due to current projects already underway in the region and the lack of robust financial performance forecasted for the CCA enterprise.
- The Tri-County Region's offshore and onshore site conditions could potentially be supportive of wind farm development (depending upon weather patterns, topography, etc.). Because wind generation projects tend to be larger undertakings to capture economies of scale, this analysis assumes that a hypothetical wind project would require a joint venture funding source (either a larger geographic area or public-private funding) and/or multiple partners/offtakers.
- The Tri-County Region has targeted solar technology manufacturing as a target industry cluster (CleanTech) and is therefore the most viable local source of new renewable energy development (according to the University of Santa Barbara Institute for Energy Efficiency).
- Comparatively, the cost of geothermal resources[141] is prohibitively expensive and biofuel resources are not a priority given emissions considerations.

Based on these parameters, CCA implementation of renewable energy generation assumes the hypothetical installation of one each of the following types of renewable energy projects:

- 1 MW Solar PV (using crystalline silicon, fixed mount system)
- 5 MW Solar PV (using crystalline silicon, fixed mount system)
- 10 MW Solar PV (using crystalline silicon, fixed mount system)
- 100 MW Wind Farm (with shared ownership)

Given the preliminary nature of this Study, it is assumed that these hypothetical solar and wind energy installations could occur anywhere in the Tri-County Region. A more detailed site assessment would need to be conducted to identify specific project locations, and the Central Coast Power CCA would need to coordinate with the applicable IOU to interconnect to the IOU distribution or, in some instances, transmission systems. Prior to establishing this interconnection, the IOU will perform a study to determine whether the electric grid can accommodate the proposed resources. If infrastructure investment will be required to accommodate the renewable generation project, the IOU and CCA must coordinate the resource, system, and interconnection planning necessary to ensure electric grid reliability and resiliency.

IMPLAN is an industry-standard economic modeling software quantifying relationships (dependence) between industries in an economy. I/O 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. I/O modeling estimates the inter-industry transactions and uses those transactions to estimate the economic impacts of any change to the economy.

IMPLAN's I/O model calculates four categories of impacts: employment, labor income, value added, and output. Employment is the number of jobs gained or lost. Labor income is 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. Total output is the total value of the revenues, sales or value of output.

I/O models are made up of matrices of multipliers between each industry present in an economy. These matrices, or tables, show 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. I/O modeling produces results in the following categories:

- Direct Effects – Increased purchases of inputs used to produce final goods and services purchased by residents. Direct effects, or first round effects, are the input values in an I/O model.
- 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.

Table 86 summarizes the Jobs and Economic Development Impact (JEDI) model inputs used for this analysis.

Table 86 Local Investment in Local Energy Efficiency and Renewable Energy Resources

JEDI Inputs	Change in Local Economic Activity ($ Millions)			
Investment of surplus funds to develop local renewable energy resources	1 MW Solar	5 MW Solar	10 MW Solar	100 MW Wind
Solar/Wind Project Construction Costs	$1.56	$7.79	$15.59	$465.55
Solar/Wind Project Annual Operating Costs	$0.18	$0.92	$1.84	$8.55
Source: National Renewable Energy Laboratory Jobs and Economic Development Impact Model; IMPLAN Group LLC Multipliers; EnerNex; Willdan, 2017				

The JEDI model classifies results in three categories:

- On-site labor and professional services results—dollars spent on labor from companies engaged in development and on-site construction and operation of power generation resources. These results include labor only, no materials. Companies or businesses that fall into this category of results include project developers, environmental and permitting consultants, road builders, concrete-pouring companies, construction companies, tower erection crews, crane operators, and O&M personnel.
- Local revenues and supply chain results—the increase in demand for goods and services in supporting industries from direct on-site project spending. Businesses and companies included in this category include construction material and component suppliers, analysts and attorneys who assess project feasibility and negotiate contract agreements, banks financing the projects, all equipment manufacturers (e.g., blade manufacturers), and manufacturers of replacement and repair parts.
- Induced results—reinvestment and spending of earnings by direct and indirect beneficiaries. Induced results are often associated with increased business at local restaurants, hotels, and retail establishments, but also include child care providers and any other entity affected by increased economic activity and spending occurring at the first two categories.

Note that most other I/O models (such as IMPLAN) and methodologies calculate the first category of economic activity as "direct impacts" and the second category as "indirect" impacts. Direct impacts refer to changes in jobs, economic activity, and earnings associated with the on-site or immediate impacts created by the investment, and would include the equipment installed onsite, the concrete used onsite, etc.

Indirect impacts refer to economic impacts associated with linked sectors in the economy that are upstream of the direct impacts, such as suppliers of hardware used to make the equipment installed onsite or the concrete used onsite. However, the economic impacts of the physical items used onsite, normally included in direct impacts, typically occur at some geographic distance from the project itself.

Because of JEDI's focus on the local impacts of a project, only the labor associated with the on-site location is counted in the first category. All equipment and supply chain effects are included in the second category.

Typically, the sum of the direct plus indirect impacts from other I/O models can be reasonably compared to the sum of on-site plus supply chain impacts as calculated by JEDI models. Induced impacts in JEDI are calculated similarly to induced impacts in other I/O models.

JEDI model results are displayed in two different time periods: construction and operations. Construction-period results are inherently short term. Construction jobs are defined as FTE, or 2,080-hour units of labor (one construction period job equates to one full-time job for one year). Although the JEDI models are based on IMPLAN methodology, which does not explicitly distinguish full- and part-time jobs, JEDI results are converted to FTE using supplementary conversion data provided by IMPLAN.

A part-time or temporary job may be considered one job by other models, but would constitute only a fraction of one job according to the JEDI models. For example, if an engineer worked only 3 months on a wind farm project (assuming no overtime), that would be considered one-quarter of one job by the JEDI model. Equipment manufacturing jobs, such as tower manufacturing, are included in construction-period jobs, as new construction drives equipment manufacturing. Operations-period results are long term, for the life of the project, and are reported as annual FTE jobs and annual economic activity, which continue to occur throughout the operating life of the facility.

JEDI results are not intended to be a precise forecast; they are an estimate of potential activity resulting from a specific set of projects and scenarios. In addition, JEDI results presuppose that projects are financially viable and can be justified independent of their economic development value.

F.2. Economic Impact Results

The following narrative provides a summary of the direct, indirect, and induced employment, labor income, output, and value added economic activity resulting from the conversion of utility bill rate savings into disposable income and local renewable energy project investment in the Tri-County Region.

F.2.a Utility Bill Savings Results

The preliminary results of the financial feasibility analysis indicate that the Central Coast Power CCA does not meet feasibility criteria, is not expected to generate revenues in excess of operating costs, and is not expected to results in utility bill rate savings. The Central Coast Power's rate savings analysis for 24 scenarios (8 participation scenarios times 3 renewable content scenarios) indicate an increase to rates and associated decreases to disposable income under the CCA. ***The hypothetical results in this section are presented solely for illustrative purposes.***

F.2.b Renewable Energy Project Investment Results

Solely for illustrative purposes, the one-time economic benefits resulting from hypothetical renewable energy project installation are estimated for three solar projects (one 1 MW project, one 5 MW project, and one 10 MW project) and one 100 MW wind farm development. Table 87 illustrates the construction and installation effects of building each of the solar power systems. For example, referring to this table, a 1 MW solar system would create roughly 2.8 jobs during construction and installation. Of this total, about 0.9 jobs would be directly involved in construction and installation while roughly 1.9 jobs would be indirectly involved with the building of the project. Module and supply chain activity would generate 2.5 jobs. Induced impacts of the construction and installation will create approximately 0.6 jobs. These induced effects would include anything from increased employment in restaurants, retail, education, and others.

Overall, the building of this solar project would generate a total of 5.9 one-time jobs, $329,000 in earnings, and $284,000 in output (GDP) in the local economy during construction.

Table 87 Economic Benefits of Construction & Installation for Reference Solar Projects

Benefit	Annual Jobs			Annual Earnings[i] ($000 2026)			Annual Output[i] ($000 2026)		
Size (MW)	**1**	**5**	**10**	**1**	**5**	**10**	**1**	**5**	**10**
Project Development and Onsite Labor Impacts									
Construction and Installation Labor	0.9	4.4	8.8	$68	$342	$683	$-	$-	$-
Construction and Installation Related Services	1.9	9.7	19.4	$85	$426	$852	$-	$-	$-
Subtotal	**2.8**	**14.1**	**28.2**	**$154**	**$768**	**$1,535**	**$-**	**$-**	**$-**
Module and Supply Chain Impacts									
Manufacturing	-	-	-	$-	$-	$-	$-	$-	$-
Trade (Wholesale and Retail)	0.2	1.2	2.5	$16	$78	$156	$11	$54	$107
Finance, Insurance and Real Estate	-	-	-	$-	$-	$-	$-	$-	$-
Professional Services	0.3	1.5	3.0	$15	$73	$147	$41	$204	$407
Other Services	0.5	2.3	4.7	$58	$289	$578	$37	$185	$370
Other Sectors	1.5	7.3	14.5	$52	$260	$521	$21	$104	$208
Subtotal	**2.5**	**12.3**	**24.7**	**$140**	**$701**	**$1,401**	**$109**	**$546**	**$1,093**
Induced Impacts									
Induced	0.6	3.2	6.4	$35	$176	$351	$175	$875	$1,750
Total Impacts	**5.9**	**29.6**	**59.3**	**$329**	**$1,644**	**$3,288**	**$284**	**$1,421**	**$2,842**

[i] Earnings and Output values are thousands of dollars in year 2026 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.

Source: National Renewable Energy Laboratory Jobs and Economic Development Impact Model; IMPLAN Group LLC Multipliers; EnerNex; Willdan, 2017.

Table 88 illustrates the construction and installation effects of building a 100 MW offshore wind farm. It is projected that roughly 148.4 jobs will be created during construction and installation. Of this total, about 80.9 jobs will be directly involved in construction and installation, while roughly 67.4 jobs will be indirectly involved with the building of the project.

Turbine and supply chain activity is expected to generate 188.8 jobs. Induced impacts of the construction and installation will create approximately 184.9 jobs. These induced effects may include anything from increased employment in restaurants, retail, education, and others. Overall, the building of this solar project is projected to generate a total of 522.0 one-time jobs, $26.21 million in earnings and $70.31 million in output (GDP) in the local economy during construction.

Table 88 Economic Benefits of Construction & Installation for Reference 100 MW Wind Project

Benefit	Annual Jobs	Annual Earnings[i] ($000 2026)	Annual Output[i] ($000 2026)
Project Development and Onsite Labor			
Construction and Interconnection Labor	80.9	$1.83	$-
Construction Related Services	67.4	$9.17	$-
Subtotal	**148.4**	**$11.00**	**$20.81**
Turbine and Supply Chain Impacts	**188.8**	**$7.27**	**$25.56**
Induced Impacts	**184.9**	**$7.95**	**$23.94**
Total Impacts	**522.0**	**$26.21**	**$70.31**

[i] Earnings and Output values are millions of dollars in year 2026 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.

Source: National Renewable Energy Laboratory Jobs and Economic Development Impact Model; IMPLAN Group LLC Multipliers; EnerNex; Willdan, 2017.

Table 89 demonstrates the O&M impacts of the reference solar installations. Combined these projects would generate the following employment, labor income, and output: approximately 18 annual FTE jobs, $4.5 M in annual labor income, and $2.5 M in annual output. Given the job and labor market in the Tri-County Region, these impacts are not material, representing approximately 0.003% of the regional job pool.[142]

Table 89 Economic Impacts of Renewable Energy Project O&M for Reference Solar Projects

During Operating Years	Annual Jobs			Annual Earnings[i] ($000 2026)			Annual Output[i] ($000 2026)		
Size (MW)	**1**	**5**	**10**	**1**	**5**	**10**	**1**	**5**	**10**
Onsite Labor Impacts, PV Project Labor Only	0.05	0.25	0.49	$230	**$1,151**	$2,303	$-	$-	$-
Local Revenue and Supply Chain Impacts	0.54	2.69	5.37	$27	**$136**	$271	$82	$410	$820
Induced Impacts	0.54	2.71	5.42	$28	**$136**	$273	$76	$380	$760
Total Impacts	**1.13**	**5.64**	**11.29**	**$285**	**$1,423**	**$2,846**	**$158**	**$790**	**$1,580**

[i] Earnings and Output values are thousands of dollars in year 2026 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.

Source: National Renewable Energy Laboratory Jobs and Economic Development Impact Model; IMPLAN Group LLC Multipliers; EnerNex; Willdan, 2017.

Table 90 demonstrates that the O&M of the reference 100 MW wind farm installation is expected to generate substantial employment, labor income, and output: approximately 118.6 annual FTE jobs, $51.78 M in annual labor income, and $39.56 M in annual output.

Table 90 Economic Impacts of Renewable Energy Project O&M for a 100 MW Wind Project

During Operating Years	Annual Jobs	Annual Earnings [i] ($M 2026)	Annual Output[i] ($M 2026)
Onsite Labor Impacts	**5.8**	**$46.65**	**$23.17**
Local Revenue and Supply Chain Impacts	**63.5**	**$3.01**	**$10.02**
Induced Impacts	**49.3**	**$2.12**	**$6.38**
Total Impacts	**118.6**	**$51.78**	**$39.56**

[i] Earnings and Output values are millions of dollars in year 2026 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.

Source: National Renewable Energy Laboratory Jobs and Economic Development Impact Model; IMPLAN Group LLC Multipliers; EnerNex; Willdan, 2017.

F.3. Strategic Economic Development Recommendations

The preliminary results of the financial feasibility analysis indicate that the Central Coast Power CCA does not meet feasibility criteria, is not expected to generate revenues in excess of operating costs, and is not expected to results in utility bill rate savings. Therefore, no recommendations are included.

G. Greenhouse Gas Emissions Impact Analysis

One goal for the CCA program is to achieve "an electric supply portfolio with lower GHG emissions than produced by the IOUs and that supports the achievement of local Climate Action Plan emission reduction goals." To determine the extent to which a CCA would achieve GHG emissions reductions through the use of renewable electricity generation, the status of the incumbent utility's renewable energy implementation must be compared to Central Coast Power renewable content scenarios.

This Study assesses GHG impact for each of the eight geographic participation and three renewable content scenarios, and two IOU supply portfolios. The bottoms-up analysis starts by determining the emissions impact of natural gas generation—the most likely displaced resource—and then adjusting the proportion of load served by natural gas resources to estimate changes in GHG emissions from various levels of renewable generation. Finally, the CCA emissions for each scenario are compared to the emissions for PG&E's and SCE's RPS portfolios to determine the incremental change in GHG emissions from the CCA power portfolio. This analysis is intended to provide a high-level, order of magnitude approximation of GHG impact for use by decision makers.

G.1. Approach to Greenhouse Gas Impact Analysis

This section discusses the modeling approach for the Study's GHG analysis. For purposes of this analysis, each MWh not served by renewable generation is assumed to be served by natural gas generation. Other GHG-free sources of electrical generation such as hydroelectric or nuclear production and the impacts of different operating conditions (e.g., always-on vs peaker) on natural gas generation emissions have not been considered.[143] Finally, accurately calculating the emissions associated with CAISO supply is not possible and therefore not part of this analysis.

The Study uses natural gas generation emission factors to provide an apples-to-apples comparison between the different CCA renewable energy content scenarios and IOU RPS scenarios. State or multiple-state level emissions data, such as the U.S. Environmental Protection Agency's eGRID data, combine a variety of resource types (renewable, natural gas, hydro, coal, etc.) along with line losses to provide a single static statewide average GHG emissions factor and are, therefore, not optimal for this purpose. Average emissions factors may not align with utility-specific supply portfolios given the performance of various plants in operating the grid. Furthermore, these figures lend little insight into the effects of increasing renewable generation content.

G.2. Emissions from Natural Gas Generation

A fossil fuel generator's efficiency in converting fuel into electricity is known as the heat rate. The EIA,[144] using a heat rate of 10,408 BTU per kWh, estimated natural gas generation emissions at 1.22 pounds of carbon dioxide (CO_2) per kWh. However, as the domestic supply of natural gas has been increasing and associated cost decreasing, the heat rate (or efficiency) of producing electricity from natural gas has also been improving. According to the California Energy Commission Quarterly Fuels and Energy Report,[145] the California heat rate for natural gas emissions in 2014 was 7,760, or 25% better than the EIA cited heat rate, translating to a lower emissions rate of 0.91 pounds of CO_2 per kWh. The Study uses a simple conversion of 2,204.62 pounds per metric ton to obtain the industry standard GHG reporting unit of metric tons CO_2 ($MTCO_2$). [146]

The heat rate (efficiency) for natural gas generation is improving over time, as illustrated in Figure 62. These improvements in natural gas generation efficiency and associated reduction in CO_2 emissions are independent of CCA implementation. This improving heat rate (efficiency) is projected to decrease GHG emissions from natural gas production across the Study period as shown in Table 91.

Figure 62 Natural Gas Generation Heat Rate (Efficiency)

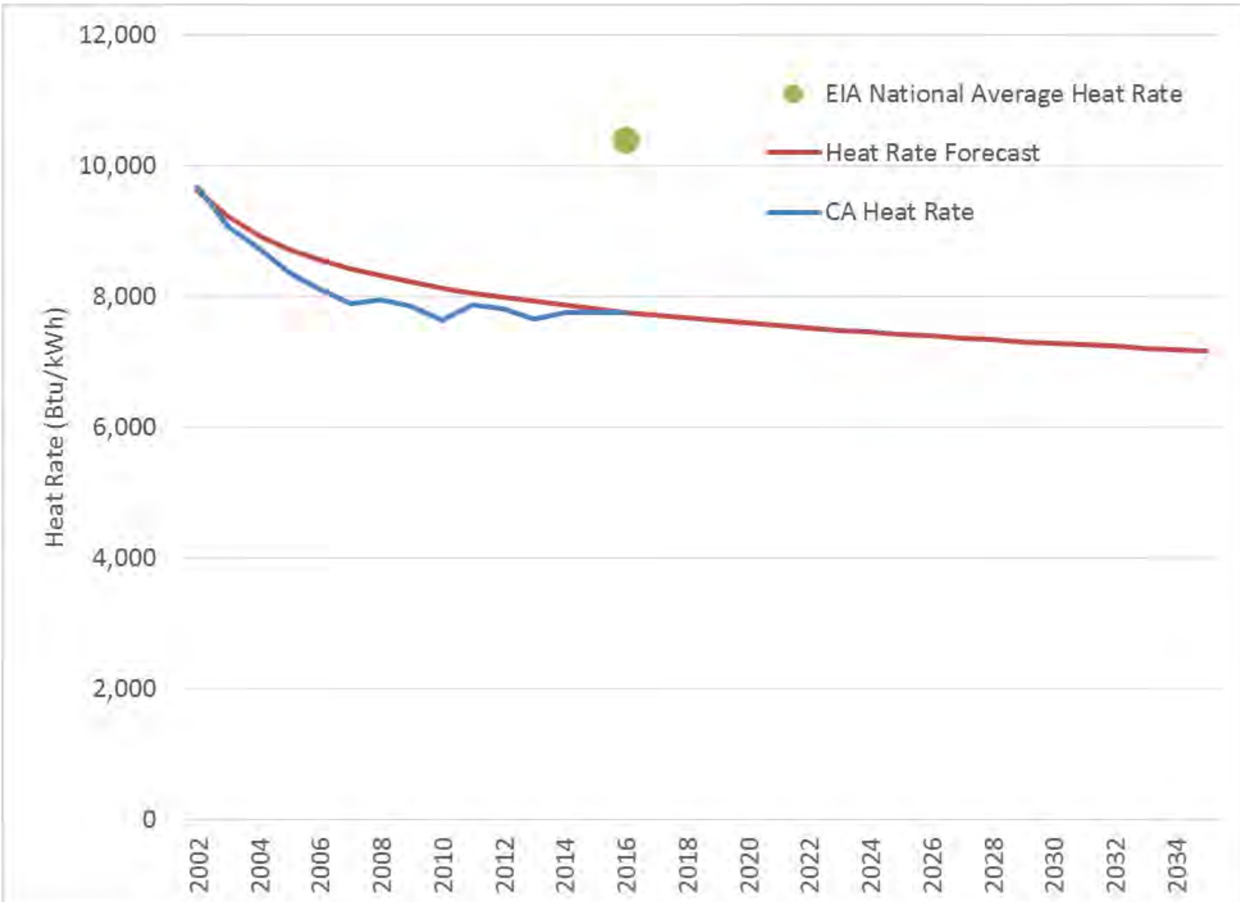


Table 91 Emissions Factor Table for Natural Gas Generation

Year	$MTCO_2$ per MWh of Natural Gas Generation
2015	0.41
2020	0.39
2025	0.38
2030	0.37

G.3. Comparison of CCA Greenhouse Gas Emissions with IOU Emissions

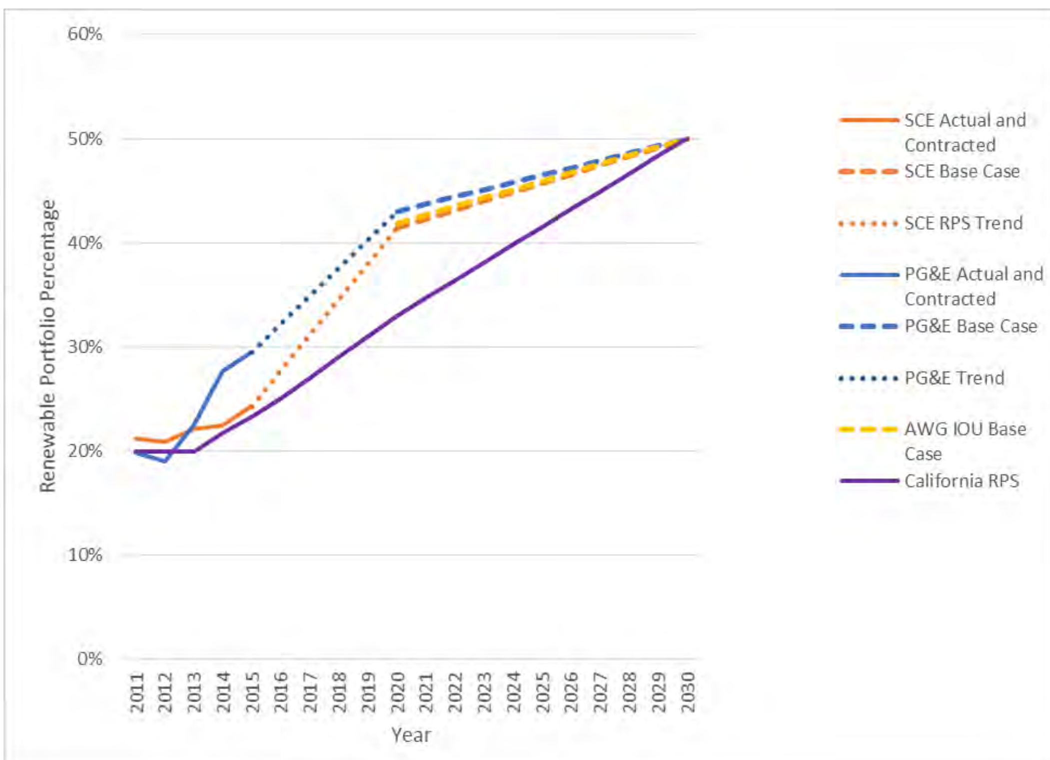
SCE and PG&E use two primary sources of electricity: RPS eligible renewable resources and natural gas resources. Unspecified sources of power, 40% for SCE and 17% for PG&E, in the 2015 power mixes shown in Table 3 are likely comprised of CAISO supplied power. According to the CPUC RPS homepage,[147] the two utilities have RPS eligible contracts and resources already in place for 2020 that exceed the 2020 RPS requirement (see Table 92).

Table 92 California Renewable Portfolio Standard

California RPS Compliance Period	Procurement Quantity Requirement	SCE	PG&E
2020	33%	41.4%	43%
2020–2029	Annual retail sales x 33%	Varies	Varies
2030	Annual retail sales x 50%	50%	50%

Figure 63 depicts the three Central Coast Power renewable energy content scenarios as well as the forecasts for each IOU's RPS eligible renewable energy content. For purposes of this Study, the IOU Base Case assumes the IOUs will progress linearly from 2020 contracted levels of renewable generation to the 50% RPS goal in 2030. Each IOU could elect to exceed RPS requirements, as they have for the 2020 time period, or follow RPS requirements. For example, PG&E has proposed, as part of the joint proposal for retirement of its Diablo Canyon Nuclear Power Plant, to include a voluntary increase in the utility's target for RPS-eligible resources to 55%, effective in 2031 through 2045.**Error! Bookmark not defined.** Senate Bill 100 w ould increase the RPS mandate to 50% by December 31, 2026, 60% by December 31, 2030, and 100% by December 31, 2045 (refer to endnote 5). Both IOU RPS scenarios assume that no additional RPS resources are procured beyond what is already contracted for 2020, although the 2020 RPS compliant resources could potentially increase by then.

Figure 63 IOU Estimated RPS Generation 2020 –2030 Based on Power Procurement Contracts Already in Place with AWG IOU Base Case

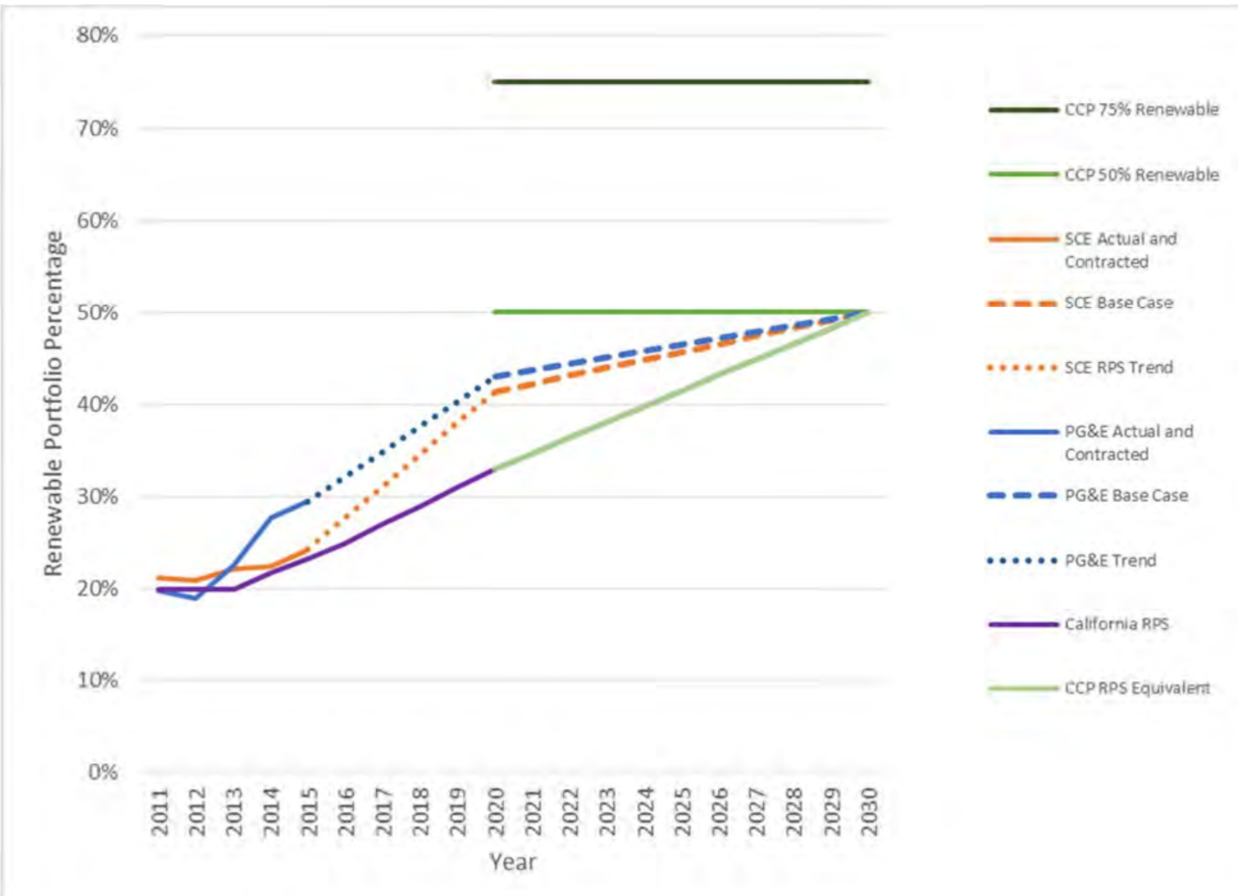


G.4. Results of GHG Impact Analysis

The Central Coast Power emissions results by participation and renewable content scenario are then compared to the IOU Base Case scenarios. IOU emissions levels are determined based on weighted customer load.[148] For example, in the AWG Jurisdictions participation scenario, 71% of the energy usage is in SCE territory, so total IOU emissions are based on 71% SCE portfolio emissions and 29% PG&E portfolio emissions.

Figure 64 illustrates the various renewable content levels and Figure 65 shows the associated emissions for the AWG Jurisdictions scenarios. As shown in these figures, the IOU Base Case is projected to outpace the RPS standard and therefore the CCA RPS Equivalent scenario would have higher emissions. CO_2 emissions for the CCA RPS Equivalent scenario converge with the IOU Base Case in year 2030 at the 50% RPS requirement.

Figure 64 IOU Renewable Content Scenarios for AWG Jurisdictions Participation Scenario



In Figure 65 the improved efficiency (heat rate) of natural gas generation can be seen in the general downward slope across the Study period, even as the renewable energy content remains constant. The lines for both the Middle of the Road (50%) and Aggressive (75%) renewable energy content scenarios have slight downward slopes, representing fewer emissions as time goes on despite a constant renewable portfolio.

Figure 65 AWG Participation Scenarios GHG Impact Analysis

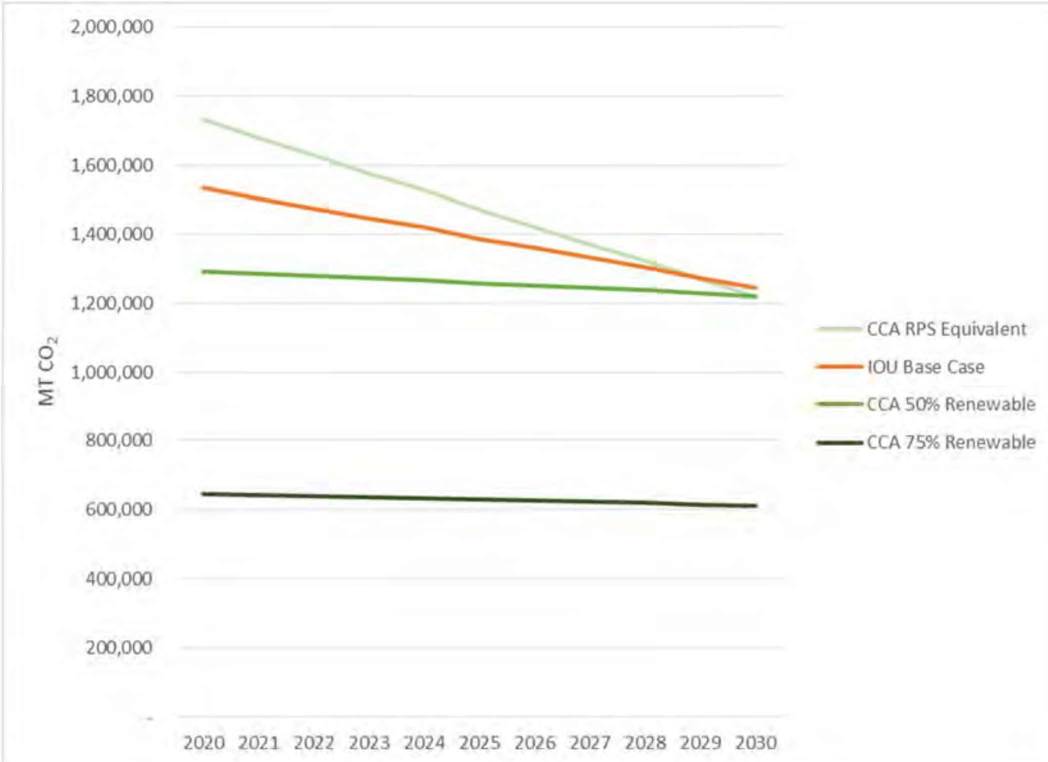


Table 93 provides the CO_2 emissions data for these scenarios. These figures are not intended to be absolute; the significant digits within the table likely overstate the level of precision in the projection. As can be seen in this table:

- The AWG Jurisdictions RPS Equivalent scenario would result in 6% higher emissions over the entire Study period compared to the IOU Base Case scenario. During the final two years of CCA operation (in 2029 and 2030), since both the IOU and CCA portfolios would have 50% renewable content, the 2% of CCA portfolio served with 100% renewable energy would result in lower emissions relative to the IOU Base Case scenario.
- The AWG Jurisdictions 50% renewable energy content scenario would reduce CO_2 emissions by 9% compared to the IOU Base Case scenario over the Study horizon.
- The AWG Jurisdictions 75% renewable energy content scenario would reduce CO_2 emissions by 55% compared to the IOU Base Case scenario over the Study horizon.

Table 93 AWG Jurisdictions Scenarios CO_2 Output Comparison with IOU Base Case

Year	IOU Base Case (MT CO_2)	CCA RPS Equivalent with 2% Opt-up (MT CO_2)	CCA 50% Renewable with 2% Opt-up (MT CO_2)	CCA 75% Renewable with 2% Opt-up (MT CO_2)
2020	1,533,129	1,731,548	1,292,200	646,100
2021	1,504,220	1,679,292	1,285,828	642,914
2022	1,475,894	1,627,880	1,279,780	639,890
2023	1,446,151	1,575,116	1,272,307	636,153
2024	1,420,994	1,527,524	1,268,707	634,354
2025	1,388,301	1,472,059	1,258,170	629,085
2026	1,360,352	1,421,904	1,251,676	625,838
2027	1,332,202	1,371,761	1,244,792	622,396
2028	1,306,669	1,324,507	1,240,175	620,088
2029	1,274,892	1,271,188	1,229,389	614,695
2030	1,246,257	1,221,332	1,221,332	610,666
TOTAL	**15,289,060**	**16,224,111**	**13,844,357**	**6,922,179**
CO_2 Reduction %		**-6% (increase)**	**9%**	**55%**
CO_2 Reduction (MT)		**(935,050) (increase)**	**1,444,703**	**8,366,882**

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III. Implementation Analysis

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III. Implementation Analysis

This section presents implementation-related information for starting up a new CCA. Given the lack of feasibility, this section is included primarily for illustrative purposes. Additional detail regarding CCA start up can be found in Appendix K.

A. Organizational Structures

Two structural considerations must be weighed as part of CCA formation:

- Organizational governance structure—determining levels of participation in and setting ground rules for: decision making, operational management and control, and policy development in areas such as supply portfolio content, local economic development priorities, and development of ancillary programs such as energy efficiency.
- Preferred operating model—which components of operations to retain in-house and to outsource.

Both decisions ultimately determine how control and decision making is distributed and managed and how much operational control remains directly under Central Coast Power.

Central Coast Power must decide between three primary options, or variants thereof, for governance and operation. The first option is to operate as an enterprise department of a single local government. The second is the formation of a Joint Powers Authority (JPA) with the jurisdictions participating in the CCA program being parties to the JPA and sharing the ongoing decision making, governing, managing, and operating responsibilities in compliance with a joint powers agreement. A third alternative is a hybrid structure where a JPA is formed to provide back-office functions (e.g., power procurement, legal/regulatory support) to member CCAs through service agreements. In this hybrid JPA model, each JPA member operates as its own CCA with individual responsibility for rate-setting, product development, marketing, etc. Each of the three organizational structures is discussed below.

A.1. Enterprise Department

As initially envisioned, Central Coast Power could be a multi-jurisdictional CCA program under five of the jurisdictional participation scenarios examined in this report. Examples of enterprise structures used by existing CCAs include: LCE at the time it launched in 2015, CleanPowerSF, and Apple Valley Choice Energy. Although the Study results do not point to a viable economic model for any of the 24 scenarios studied, it is possible that a single jurisdiction could form its own Enterprise Department CCA. Similarly, one of the Central Coast Power jurisdictions could launch first as an enterprise department with the possibility of later adding other jurisdictions to form a JPA or hybrid JPA if the economics later prove viable.

In a sole jurisdiction or Enterprise Department approach, the county or city has complete say in the development of policies and procedures for the CCA program, meaning these can be solely tailored for and responsive to the stakeholder and constituent objectives and preferences of that local agency.

The county or city would be responsible for, among other things:

- Setting policy priorities;
- Managing, operating, and staffing the CCA program;
- Developing customer rate categories, rate structures, and potentially, discounts;
- Decisions about renewable portfolio content or local power generation;
- Local economic development strategies related to energy;
- Formulating financial and debt policies and engaging in financing activities;
- Developing and operating energy efficiency, demand response, or other related programs; and
- Engaging in regulatory and legislative activities relative to energy.

Along with greater autonomy in the above matters, the county or city would assume the risks, liabilities, and costs associated with operating the CCA program, which is a disadvantage. In the sole jurisdiction model, a county or city would establish the CCA program as an enterprise fund. Enterprise funds are commonly used for public utilities such as electric, water and wastewater, or other county or city functions where a public service is operated and provided in a manner, similar to a business enterprise, where fees and charges are collected for services provided, and accounting and budgeting are separate from an agency's general fund. Setting up the CCA program as an enterprise fund provides a structure where the revenues and expenditures are separated into unique funds, budgeted for independently, and reported on separate financial statements. In an enterprise structure, financial transactions are reported like business activity accounting; revenues are recognized when earned and expenses are recognized when incurred. Establishing an enterprise fund provides management and CCA program customers with more visibility and accountability, and the ability to more easily separate and measure performance, analyze the impact of management decisions, determine the cost of providing electric service, and use this information to develop cost-of-service electric rates.

Enterprise accounting allows a public agency to demonstrate to customers, the public, and other stakeholders that the cost of power is being recovered through its rates, and not being subsidized or comingled with other government funds or functions. In this case, agency staff would work with appropriate legal counsel to explore options for controls and structural safeguards to insulate it and minimize risk to the local general fund. In the case of LCE, during their operation as a sole agency in an enterprise structure, they instituted a lockbox arrangement, governed by agreements between the City and its vendors, that provided separation between CCA program operations and the City's general fund, and limited liability to the City while providing required visibility for involved parties.

Benefits:

- Creating a sole jurisdiction enterprise is less time consuming than forming a JPA with fewer parties to agree on key decisions and policies
- Decision-making processes and management are simplified and streamlined
- More local control over programs, customer relations, rates, vendors, operating decisions, etc.

Risks:

- One local agency responsible for costs and risks, no pooling of risk with other agencies
- Less economy of scale, and thus less cost-effective than a JPA
- Fewer resources due to smaller size
- Less financial and credit stability than a larger, more diversified JPA, possibly resulting in reduced negotiating (buying) power and less advantageous credit terms when borrowing
- One agency responsible for development of staffing and structure, procurement, etc.

A.2. Joint Powers Authority

A traditional JPA is an independent agency that operates on behalf of the public agencies that are party to its creation. In this approach, the counties and cities participating in the JPA effectively share responsibility. Sections 6500 to 6536 of the California Government Code constitute the enabling legislation for JPAs, and the CPUC specifically allows a CCA program to be carried out under a joint powers agreement between entities that each have the capacity to implement a CCA program individually. Examples of CCA JPAs include: MCE Clean Energy (formerly Marin Clean Energy), Sonoma Clean Power, Peninsula Clean Energy, Silicon Valley clean Energy, and Redwood Coast Energy Authority.

A JPA may be formed when it is to the advantage of two or more public entities with common powers to combine resources, or when local public entities wish to pool with other public entities to save costs and/or gain economies. It can also be employed to provide the JPA with powers and authority that participating entities might not have on their own. A JPA is a legal and separate public entity with the ability to enter contracts, issue debt, and provide public services, among other things; and like its participants, it would have broad powers related to the operation and management of the CCA program and the study, promotion, development, and conduct of electricity-related projects and programs.

At the time the JPA is created, a governing board would be established, which would have primary responsibility for managing the governance and operation of the CCA program. The JPA would effectively be the CCA program, and member counties and cities would authorize their participation in the JPA by resolution or ordinance. Essential ground rules would be negotiated and memorialized at the time the CCA program and JPA are established, such as financial and staffing commitments of each participating agency, division of responsibilities among member agencies and the JPA, and probably most critically, the composition of the board along with voting and decision making policies and procedures. The participating JPA members would participate in decision making through their representation on the board, per the JPA agreement.

Once created, the JPA would be the face of the CCA program, and would have a direct relationship with CCA program customers for activities such as rate and tariff development, customer care and billing, and the development of local customer programs, such as energy efficiency incentives. On the operating side, the CCA program would be responsible for activities such as resource planning and power procurement, management of contracts with vendors and suppliers, financing activities, program marketing, regulatory and legislative activities, and interacting with the IOUs and CAISO.

The JPA structure may reduce the risks of implementing a CCA program to the participating counties and cities by limiting their liability and exposure of their financial assets, and distributing the risks and costs.

With the advantage of scale, a CCA program operated under a JPA could enjoy increased negotiating leverage for power purchases, access to better financing terms for borrowing, and operating efficiencies gained by combining back-office functions such as billing and accounting. These benefits could theoretically pass through to customers through more competitive electric rates, although customer rate setting considers an array of policy objectives and choices, beyond simply the cost of power. A larger JPA could also wield more political and legislative influence, which could be beneficial when participating in CPUC or other regional or state regulatory or legislative efforts.

A key tradeoff to the above listed benefits of a JPA is that decision making is divided and more complicated, and management independence is reduced. Objectives and goals of participating agencies will likely differ and it is likely that participating agencies will have to deprioritize some goals in the name of compromise. Reduced autonomy may manifest when setting priorities for development of local generation resources, supply portfolio content, economic development activities, and the importance of support programs.

As mentioned previously, when the JPA is formed, a board must be appointed to set policy and make decisions. The makeup of this board is subject to negotiation among the participating entities, but would likely be made up of elected officials from each. The process of determining the makeup of the board, and each respective member's voting weight can be based on several factors, such as the percentage of customers or load, or relative financial contribution. In any case, decision making is certainly more complicated. The number of stakeholder interests and priorities are multiplied, and in many cases, reaching consensus on key decisions is more complex and time-consuming than if only one agency were involved.

Benefits:

- The local agencies who are party to Central Coast Power will share the costs and risks of the CCA program, and have input and involvement with CCA program activities
- Financial resources and access to credit terms can be improved through greater scale
- Resources of participating agencies are pooled (financial, expertise, political influence)
- Staffing and support can be consolidated and centrally managed, promoting efficiency and reducing duplication of resources.

Risks:

- JPA formation is time consuming; approach and structure must be negotiated and agreed to
- Equitable representation for all members balanced against the need for effective and efficient management and decision making will be a challenge, given the diversity of the communities who will potentially participate
- Decision-making will likely be time-consuming and cumbersome, during formation and ongoing CCA program operation. Consensus based decisions will be more difficult to achieve given range of local interests and political realities
- Reduced local control over rate setting and customer support

A.3. Hybrid Joint Power Authority

A Hybrid JPA combines aspects of a single-entity enterprise and JPA, and addresses some of the shortcomings of each. The only known example of this model in operation so far is the California Choice Energy Authority (CCEA) that was formed by LCE and the Cities of Lancaster and San Jacinto. South Bay Clean Power—a coalition of CCA advocates in Los Angeles County's South Bay and Westside communities—also promotes a similar hybrid JPA model, though no CCA has yet been formed.

Under a hybrid option, each participating city or county would form its own CCA program, presumably utilizing a sole jurisdiction enterprise approach. A primary CCA program JPA would also be created with a lead agency, the role LCE has assumed in CCEA. This lead, or primary, JPA would assume responsibility for overall management and common functions such as resource management, power procurement, contract management, regulatory and legislative support, and billing and data management, among others. The individual CCA programs would assume local responsibility for rate setting, program marketing, and other program aspects where local control is preferred. The final division and sharing of responsibilities is flexible and can be negotiated and formalized at the time the CCA program is established.

Local governments would have greater autonomy and local control under the hybrid JPA model, but they would also bear some local responsibility and staffing requirements and assume risks independent of the lead JPA. Billing and some customer support activities may still be costlier overall, given the likelihood that each individual participating CCA program will have its own rates, and will need to be administered and billed separately. Under this option, each member would need to collect sufficient rate revenue to cover its individual costs, as well as its share of the overall program costs. This approach may realize many of the cost savings advantages of a typical single CCA JPA structure, while allowing individual members greater autonomy and control.

Initially, LCE was formed as a sole jurisdiction CCA program. However, in 2015 Lancaster was approached by another city for assistance in forming, implementing and operating a CCA program. During this time, Lancaster examined the structural alternatives (sole jurisdiction and traditional JPA) and determined that a one-size-fits-all structure wouldn't work. They combined elements of both approaches to gain the advantages of economy, efficiency, and risk mitigation inherent in a JPA approach, with the local control, revenue realization and decision making of a sole jurisdiction approach.

LCE and the Cities of Lancaster and San Jacinto formed CCEA, a JPA with the Lancaster City Council serving as its Board of Directors, and Lancaster city staff serving most management roles. The Board of Directors serves as the legislative and operational oversight of the corresponding contractual relationships with associate member agencies. San Jacinto entered into an associate contractual relationship with CCEA, with pooled functions carried out by CCEA as described above, and local functions retained by San Jacinto. CCEA contracts directly with several vendors for certain highly specialized aspects of CCA program operation such as power procurement and supply portfolio management, CAISO scheduling, and regulatory and legal support.

Following inception, the City of Pico Rivera also joined CCEA, and one other city is currently considering enrolling. Each associate member executes its own contract with the JPA, and the division of local/general responsibilities is specific to each. The fixed costs of overall program administration are shared among the associate members, while variable costs attributable to each member are borne by that member only. As additional members join, the distribution of fixed costs changes, and those fixed fee arrangements are periodically recalibrated for all the members. As more agencies join, the sharing of fixed costs over a broader base benefits all participating members. In addition to ongoing operation and management, CCEA can also assist in the feasibility and implementation process.

Benefits:

- Benefits of scale, especially reduced staffing requirements and access to greater financial resources, for pooled functions
- Joint exercise of selected powers
- Shared costs with other JPA members
- Benefits of knowledge with pooled expertise and experience
- Retention of local control of customer facing functions by each CCA program, subject to specific agreement parameters, which would be negotiated at implementation

Risks:

- Higher overall JPA administrative costs for billing, marketing and communications, etc., as these are not aggregated and assuming each local CCA program has its own rates
- More local responsibility for management, staffing and resources, depending upon negotiated JPA agreement
- Increased overall cost for support and coordination since there would be many CCA programs and each would be required to undertake certain coordinating activities with the IOUs, CAISO, and the CPUC
- Decision-making related to pooled activities ceded to JPA

B. Operational Models

Once feasibility is determined, and implementation begins, Central Coast Power must also decide which functions related to the startup and operation of the CCA program to retain in-house with direct staffing and which functions to outsource to third party vendors.

Two principal options, and scaled combinations between the two, exist for operation: full in-house operation with existing or added staff; and full outsourcing with the local government or JPA staff only involved to the extent necessary to let and administer contracts and manager vendors. The likely option for the CCA would be a combination of the two, with highly technical functions outsourced, and other public-facing functions like communication, customer service and billing, maintained in house. As noted in the feasibility reports for Inland Choice Power and San Jose Clean Energy, many existing and proposed CCA programs are selecting a high degree of internal staffing and control, with only certain highly specialized and non-public facing functions outsourced. As discussed in the preceding section, CCEA uses a hybrid model to outsource highly specialized and technical functions, while utilizing CCEA (LCE) staff to perform some of the overall management functions. The range of options depends upon the degree of operating control a CCA program wishes to maintain, the costs associated with maintaining those functions, and the degree of risk it is willing to accept on its own or delegate to (and pay) third party providers to assume.

Examples of some of the categories of operating activities:

- Power procurement and scheduling
- Finance, budgeting, and accounting
- Billing and customer service
- Communications, outreach, and public relations
- Specific programs such as demand response and energy efficiency
- Regulatory monitoring and compliance, CPUC filings, etc.

Central Coast Power will need to determine which aspects of the CCA program will be operated and managed by local staff and which aspects are candidates for outsourcing to other entities. The CCA program could break up the various services required to operate the CCA and select vendors for certain specialized functions where specific expertise or experience is necessary, for instance power procurement and/or CAISO scheduling. Or if a hybrid organization structure is implemented, like CCEA, certain functions could be provided by the JPA and others by the local participants.

Multiple third party ESPs could provide energy procurement services as well as the required Schedule Coordinator interface to the CAISO. In addition, SCE and PG&E provide services, including billing, for CCA programs within their service territories and offer additional support services that can be used by CCA programs for a fee.[149]

While outsourcing services to an ESP may reduce initial startup and operational costs, the cost over time will likely be greater. Additionally, outsourcing to an ESP will have less local economic benefit than having CCA program staff perform these functions. This option involves less direct control, where an ESP could provide most of the key functions of the program, including power procurement and rate development, and even scheduling, billing, and customer service. The CCA's role would be providing higher level administrative and management functions, and serving as the connection between the vendor(s) and the customers. This "turn-key" approach is what Redwood Coast Energy Authority has chosen with The Energy Authority as its primary program implementer for the specialized energy planning, procurement, scheduling, and risk management functions.

It may be possible under this model for the CCA program to negotiate terms with its vendor(s) to transfer much of the risk to them, subject to the vendor's willingness to accept them. There is a cost tradeoff for this transfer of risk. An ESP may be willing to guarantee certain service components, such as savings, rate certainty, renewable content, etc., but will likely require a greater premium for doing so. Another tradeoff for transferring this risk is transferring potential upside reward, such as financial savings or return, should the CCA program negotiate advantageous power purchase terms on its own. A thorough and detailed procurement and negotiating process can provide the CCA program with much more detail about which components of CCA program operation can be cost-effectively outsourced, provide an indication of the terms that vendors may be willing to provide or negotiate, and generally provide more specific information upon which to base this decision.

Other services such as billing, accounting, outreach, and customer service could be maintained in-house, either because the counties and cities already have similar experience or resources with the necessary skills, or the visibility of these critical functions requires greater local control and management. This type of structure requires more commitment of local resources, staffing, and management time than the strict outsourcing model, but allows more control. In the direct control model, the CCA would be responsible for hiring and monitoring vendors, and would develop its own program policies and specific customer rates, which could incorporate specific local policy objectives.

B.1. Energy Related Services

Central Coast Power can develop and manage a supply portfolio in numerous ways. It can take a proactive management role and develop all the electric operations functions internally (i.e., electric supply procurement, which includes capacity, RA requirements, ancillary services, risk management processes and programs required to manage the supply portfolio, long- and short-term load forecasting and schedule coordination), or these functions can be outsourced to a third party(s) to perform via a request for proposals (RFP) process. A "full requirements" contract structure could be created where a third party performs all the operations necessary to deliver the minute-to-minute shaped energy, including all required market components to Central Coast Power's delivery point at a fixed price. While convenient, these types of contracts will generally come with a premium price (particularly if fixed price/multiyear terms are requested) and may end up being more expensive than the utility generation costs as the supplier has to take on price and volumetric risk for all energy and market products and services.

A slightly different outsourcing structure could have a third party provide a shaped energy or volume product at a fixed price over one-, two-, or three-year terms. The shaped energy product would be delivered to the Central Coast Power delivery point, with monthly fixed volumes based on Central Coast Power's historical load profile at either 100% of historical volumes or some equally weighted percentage of the profile. Any actual use above or below the historical use levels would be purchased or sold into the CAISO day-ahead market and could be settled at actual price or another settlement formula (e.g., load-weighted average of the CAISO hourly day-ahead market prices at the SCE load aggregation point). Other supply-related products and their associated costs could be broken out as separate products (e.g., RA, ancillary services, schedule coordination services, etc.) to create price transparency for Central Coast Power. This approach will carry a premium to cover the supplier's risk exposure, but because volumes are fixed, the exposure is less (and thus the premium will be lower compared to the full requirements approach). This hybrid approach aligns with the assumed power procurement structure for the CCA where PPAs provide energy and resource adequacy for the lower bound 90% confidence level load forecast and the CCA bears the CAISO market exposure risk.

The power procurement structure that will work best for Central Coast Power is a function of its risk appetite and tolerance, resource availability, skill sets, and cost structure.

Other portfolio management structures are certainly possible. However, the structure that will work best for Central Coast Power is a function of its risk appetite and tolerance, resource availability, skill sets, and cost structure. A third party outsourcing approach may make sense in the early years of the program, which allows Central Coast Power to gain experience and confidence as customer groups are phased into the program. Assuming Central Coast Power follows the model from other CCA program implementations, a third party ESP could be hired to perform power procurement, CAISO schedule coordination, and customer service operational support. These services can be summarized as Energy Supply, Portfolio Management, Customer Care, Data Management and Billing, and Start-Up Support Services.

Energy Supply can include shaped energy where the supplier would be obligated to deliver electric energy requirements in quantities sufficient to meet all the needs of participating customer accounts. The supplier would be responsible for delivering the energy to the Central Coast Power delivery point as defined by the CAISO. Shaped energy would match the aggregate hourly load profile of the Central Coast Power and take distribution line losses into account.[150] Additionally, the supplier would be responsible for participating as needed in both CAISO day-ahead and real-time markets, as required to effectively and efficiently meet the CCA's load and demand. To participate in the CAISO markets, the supplier will need to have a CAISO certified Schedule Coordinator. Additionally, the supplier will be responsible for meeting the RA requirements described in Section II.B.2.b, and making the appropriate filings with the CPUC.

The CCA program will be responsible for energy resource planning to understand the customer load forecast and develop requirements for generation resources to meet customer electricity demand. The approach described in both Section II.A Load Study and Forecast and II.B Power Procurement Portfolio Scenario Analysis provide some insight into the process of analyzing electricity usage trends, estimating the resource needs to meet those trends, and developing a diverse energy supply portfolio to manage risk. Resource planning involves developing load forecasts for its subscribed customer base to support portfolio planning, power product acquisition, and RA requirements on the CAISO annual and monthly reporting schedules. In addition, the CCA will need longer-term strategic integrated resource planning that includes renewable energy generation under the CCA's control and future energy efficiency and demand management programs currently under consideration. Additional information on this topic can be found in Appendix K.

B.2. Customer Care

Customer Care support includes customer service, data management, and billing services to support the CCA program's customer enrollment, billing, and customer services activities. This includes the capability of managing interfaces with the CAISO, PG&E, and SCE to perform billing and settlement processes. Customer Care services are comprised of:

1. EDI to obtain customer usage data from the IOU Meter Data Management server and exchange CCA Service Requests from the IOUs to exchange customer account information updates and changes.
2. Maintaining a customer database of all Central Coast Power customers and identify each customer's enrollment status, payments, and collection status.
3. Staffing a call center to receive calls from customers and report on call center performance including inquiries received, the average time required to respond to the inquiry, and the percentage of issues resolved per inquiry.
4. Providing billing administration and support with rate schedules and associated bill calculation.
5. Provide status reporting such as billing information (usage, amount, customer information, etc.), payment transactions, delinquent accounts, exceptions (usage delayed, usage received but unbilled, usage gaps, etc.), new and departing accounts, billing error rate, and timeliness.
6. The Customer Care service provider would be responsible for providing the Central Coast Power with Settlement Quality Meter Data as required by the CAISO.

B.3. Recommendations for Operational Model

A proven approach for an initial CCA program operational model is for the CCA program to contract with an ESP for energy related services and another ESP for the non-energy related services (e.g., resource adequacy) that it does not wish to remain direct control over. Then as the CCA program moves forward with operations, some services may be taken back in house as appropriate, so that the ultimate structure is a hybrid of in-house and outsourced services.

The risk in this approach is that ESPs are for-profit entities that will be providing the core operational functions for a CCA program while competing with decoupled IOUs that do not earn profit on electricity sales.[151] Instead, IOUs earn a regulated rate of return on infrastructure capital investments and maintenance to maintain a reliable distribution grid. Therefore, a for-profit energy supplier to a CCA program introduces risk that the mark up in price to the CCA program could exceed the IOU cost of power – especially if the IOU large hydroelectric generators come back on line after the California drought. Further, as discussed in preceding sections, LCE and CCEA have found success contracting with vendors for areas of CCA program operations where specialized and/or technical experience is vital, then utilizing agency staff for some general back office functions.

C. Local Programs and Development

A primary potential benefit of a CCA is more localized control over the energy programs available to constituent customers. If the CCA were feasible, it would potentially have the ability to offer incentives to encourage behaviors that assist in attaining Climate Action Plan goals, or in supporting specific demographics. Such incentives could be used to expand Plug-in Electric Vehicles (PEV), deployment of solar DER, assist low income customers, or attract businesses as discussed below.

However, it is important to understand the relationship of a CCA developing programs that may overlap with programs that are already established by the IOUs. A CCA is not at liberty to act unilaterally in local interests, as it is still be subject to the market regulations established by the CPUC. CCA customers will continue to be eligible for the incumbent utility's energy efficiency and demand response programs after CCA enrollment. Additionally, CCAs can use energy efficiency funds collected from the IOU servicing their territory after applying to the CPUC to allocate a portion of the funding that the IOU collects for CCA energy efficiency programs. However, the CPUC requires that energy efficiency programs be cost-effective and lead to direct energy savings. In addition, the CPUC will provide funding for unique programs proposed by Central Coast Power CCA that do not duplicate programs currently offered by the incumbent utility. Currently, MCE is the only CCA that is a CPUC-approved energy efficiency program administrator other than the IOUs, though others (including LCE) are pursuing or plan to pursue this option.[152,153] More information on possible energy programs to be considered by the CCA can be found in Appendix K.

IV. Conclusions and Recommendations

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IV. Conclusions and Recommendations

This section presents the Study's conclusions and recommendations.

Feasible Geographic Scenarios: The results of the Study indicate that no geographic participation scenario meets feasibility criteria for a newly created CCA. It is not the size of the CCA that is the primary driver of results; but rather the competitiveness of the CCA's rates against the incumbent utilities, given the power procurement costs and IOU CRS charges assumed.

Recommended Renewable Energy Content: Given that the results of the Study indicate the CCA does not meet feasibility criteria under any renewable energy content scenario, no recommendations are made in terms of pursuing a particular renewable content strategy or phase-in plan.

Recommended Implementation Strategy: Given that the results of the Study indicate the CCA does not meet feasibility criteria, it is not recommended that Central Coast Power pursue a new CCA at this time. However, individual jurisdictions may wish to consider joining operational or in-development CCAs if the economics and policy objectives align.

Risk Management: Given that the results of the Study indicate the CCA does not meet feasibility criteria, no CCA-specific risk management strategy is recommended. However, an ongoing, proactive approach to understanding evolving CCA issues, engaging as a stakeholder in regional CCA discussions, and involvement with regulatory decision-making is recommended, as outlined in the following discussion of next steps.

Next Steps: Given the dynamic nature of power markets and the regulatory landscape concerning CCA in California, and in light of the results of this Study, the following next steps are recommended for Central Coast Power:

1. Continue to monitor market and regulatory conditions surrounding CCA in California.
2. Explore alternative avenues to achieve goals for local control, renewable power, and sustainability initiatives.
3. While waiting to determine if conditions for CCA feasibility improve, given the nature of the PCIA and PAM, and attendant risk to a CCA program, prioritize these issues and engage with the CPUC, IOUs, and other stakeholders.
4. Consider becoming a member of the statewide California CCA (CalCCA) lobbying association[154] to engage with other CCAs and learn from their experiences, understand the changing CCA landscape, and gain access to pooled advocacy resources and insight into what other CCAs are doing.
5. Engage with both IOUs to ensure that grid modernization efforts pursued by SCE and PG&E support the CCA local renewable generation goals.

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V. Notes

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V. Notes

[1] Community Choice Aggregation Fact Sheet, funded by California Energy Commission and Department of Energy prepared by the Local Government Commission - https://www.lgc.org/resources/community-design/lpu/may2015/

[2] CPUC RPS Overview - http://www.cpuc.ca.gov/RPS_Overview/

[3] U.S. Department of Energy, Energy Information Administration's Annual Energy Outlook 2017, Tables 6.7b, 8.2, 8.3, 14-1, and 15-1. https://www.eia.gov/outlooks/aeo/

[4] Joint Proposal of Pacific Gas and Electric Company, Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees and Alliance for Nuclear Responsibility to Retire Diablo Canyon Nuclear Power Plant at Expiration of the Current Operating Licenses and Replace it with a Portfolio of GHG Free Resources, June 21, 2016, page 1. https://www.pge.com/includes/docs/pdfs/safety/dcpp/JointProposal.pdf

[5] California Senate Bill No. 100, Introduced January 11, 2017, An act to amend Sections 399.11, 399.15, and 399.30 of, and to add Section 454.53 and 740.15 to, the Public Utilities Code, relating to energy. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[6] This 15% is in addition to direct access loads that have been excluded from potential CCA program load.

[7] For the rate comparisons, the Department of Water Resources Bond Charge and the Competitive Transition Charge have been included in the IOU generation rates for comparison purposes. These charges are embedded within the CCA proxy generation rate; and both IOU and CCA customers pay them.

[8] The Community Environmental Council also contributed towards the cost of this Study, but was not a member of the Advisory Working Group.

[9] Status and Trends in the U.S. Voluntary Green Power Market establishes that across the United States "customer participation in opt-in renewable products is generally below 2%." Because the Tri-County Region is generally considered to have a higher percentage of renewable energy advocates than the national average, 2% was considered for this Study. https://energy.gov/eere/analysis/downloads/status-and-trends-us-voluntary-green-power-market

Marin Clean Energy's 2017 Integrated Resource Plan stated that "[a]s a percentage of MCE's total annual electricity sales, Deep Green participation currently represents approximately 2.6% of MCE sales." https://www.mcecleanenergy.org/wp-content/uploads/2017/07/MCE-2017-Integrated-Resource-Plan-Rev2017.04.07.pdf

[10] Refer to Note 2.

[11] Electric Load-Serving Entities (LSEs) in California:
http://www.energy.ca.gov/almanac/electricity_data/utilities.html

[12] National Rural Electric Cooperative Association - https://www.electric.coop/

[13] CPUC Registered Electric Service Providers: https://apps.cpuc.ca.gov/apex/f?p=511:1:0::NO:::

[14] Energy Information Agency, California Assembly Bill 1890: http://www.leginfo.ca.gov/pub/95-96/bill/asm/ab_1851-1900/ab_1890_cfa_960408_172203_sen_comm.html

[15] AB 1X subsequently froze DA so that only customers already enrolled could receive electricity from ESPs. In 2013, DA was partially re-opened to enable the total electricity sold by ESPs to increase back to pre-AB 1X levels. CPUC - California Direct Access Program: http://www.cpuc.ca.gov/General.aspx?id=7881

[16] Utility Distribution Company -
https://www.caiso.com/participate/Pages/UtilityDistributionCompany/default.aspx

[17] http://www.energy.ca.gov/maps/serviceareas/CA_Electric_Investor_Owned_Utilities_IOUs.pdf

[18] San Joaquin Valley Power Authority (SJVPA) was one of the first jurisdictions to explore CCA in California and also spanned SCE and PG&E service territories but ultimately it did not progress to CCA implementation after filing their CCA Implementation Plan with the CPUC.
http://lgc.org/wordpress/docs/freepub/newsletter/jan_feb2007/page02.html
http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5882

[19] SCE Direct Access Rule: https://www.sce.com/NR/sc3/tm2/pdf/Rule22.pdf
PG&E Direct Access Rule: https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_22.pdf

[20] Community Choice Aggregation En Banc Background Paper:
http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452358

[21] Load serving entities in California include investor owned utilities (San Diego Gas & Electric, Southern California Edison and Pacific Gas & Electric) in addition to electricity service providers serving the electricity needs for direct access customers.

[22] Assembly Bill No. 117, CHAPTER 838 Electrical restructuring: aggregation. An act to amend Sections 218.3, 366, 394, and 394.25 of, and to add Sections 331.1, 366.2, and 381.1 to, the Public Utilities Code, relating to public utilities. http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_bill_20020924_chaptered.pdf

[23] https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=366.2&lawCode=PUC

[24] https://www.mcecleanenergy.org/

[25] http://sonomacleanpower.org/

[26] http://www.lancasterchoiceenergy.com/

[27] https://sfwater.org/index.aspx?page=748

[28] https://www.peninsulacleanenergy.com/

[29] Refer to Note 20.

[30] LA County CCA Business Plan: http://file.lacounty.gov/green/cms1_247381.pdf

[31] http://www.cvag.org/downloads/admin/tac/TAC_11_14_2016SR7B.pdf

[32] http://montereybaycca.org/

[33] County of Santa Barbara, Energy and Climate Action Plan, May 2015: http://longrange.sbcountyplanning.org/programs/climateactionstrategy/docs/BOS051915/Attachment%20B_ECAP.pdf

[34] County of Ventura Climate Protection Plan Annual Report: https://www.ventura.org/sustain/downloads/climate_protection_plan.pdf

[35] County of San Luis Obispo EnergyWise Plan: http://www.slocounty.ca.gov/getattachment/d8cf48aa-eeb4-403b-81cd-e5da063458dc/EnergyWise-Plan-Report_2016-Update.aspx

[36] CPUC 33% RPS Procurement Rules - http://www.cpuc.ca.gov/RPS_Procurement_Rules_33/

[37] Power Content Label required by AB 162 (Statute of 2009) and Senate Bill 1305 (Statutes of 1997): http://www.energy.ca.gov/pcl/labels/

[38] Analysis completed by EnerNex of CCA-INFO data provided by the IOUs. More information on this process is available in Section II.A.

[39] Refer to Note 2.

[40] Refer to Note 36.

[41] CPUC RPS home page accessed in mid-March, 2017: http://cpuc.ca.gov/RPS_homepage/

[42] Ibid
Existing CCAs in California have reported achieving high renewable mixes, including MCE Clean Energy's current base level of 50% renewable. However, CCA renewable supplies for Marin and Sonoma have historically relied on Category 2 and Category 3 Renewable Energy Credits which cannot be delivered to the California Balancing Authority (aka CAISO). Regulatory filings indicate that Marin had 31.8% RPS and Sonoma had 43.3% RPS in 2014.
http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5775
Marin Clean Energy Renewable Options: https://www.mcecleanenergy.org/your-energy-choices/

[43] Energy Information Administration's Frequently Asked Questions: https://www.eia.gov/tools/faqs/faq.php?id=427&t=3

[44] CPUC 33% RPS Compliance Filings: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5775

[45] SCE 2015 RPS Procurement Plan Volume 1: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/354EAA212193CD0B88257E97007A2798/$FILE/R.15-02-020_RPS_SCE%202015%20RPS%20Procurement%20Plan%20Volume%201_Public.pdf

[46] Refer to Note 5.

[47] Refer to Note 4.

[48] CPUC Net Energy Metering (NEM) and NEM Cap starting 2017 - http://www.cpuc.ca.gov/general.aspx?id=3800

[49] "How Fracking Affects Natural Gas Prices": http://www.investopedia.com/articles/markets/080814/how-fracking-affects-natural-gas-prices.asp

[50] Outcomes of other CCA feasibility studies support that opt-out rates are not drivers of feasibility results.

[51] CPUC Other Tariff Rates and Services: http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/52127.doc

[52] San Jose Clean Energy Feasibility Study: https://www.sanjoseca.gov/DocumentCenter/View/65896

[53] Ibid

[54] Cited in the San Jose Clean Energy Feasibility Study with no source provided. Refer to Note 52.

[55] Pre-Feasibility Study for CCA in Torrance, CA: http://file.lacounty.gov/SDSInter/green/242553_USCCommunityChoiceAggregationinTorrance,CA-02.2014.pdf

[56] Hart, A., *Sonoma Clean Power Becomes County's Dominant Energy Supplier*, The Press Democrat, May, 31, 2015. http://www.pressdemocrat.com/news/3983569-181/sonoma-clean-power-becomes-countys?artslide=0

[57] Inland Choice Power CCA Business Plan: https://www.cvag.org/library/pdf_files/enviro/CCA_CVAG_WRCOG_SBCOG_Final_Feasibility_Study%20_12_08_16.pdf

[58] Refer to Note 30.

[59] Ibid

[60] Cited in the San Jose Clean Energy Feasibility Study with no source provided. Refer to Note 52.

[61] Marin Clean Energy "Deep Green" program: https://www.mcecleanenergy.org/dg-enroll/
Sonoma Clean Power "Ever Green" program: https://sonomacleanpower.org/your-options/evergreen/

[62] The beta distribution used in this Study is similar to the normal bell curve distribution but shifts the outcomes to more accurately portray the CAISO prices observed. That is, the beta distribution accounts for the fact that CAISO price averages are not distributed in the middle of the max and min prices. More information on beta distributions can be found here: http://mathworld.wolfram.com/BetaDistribution.html

[63] CA AB 2514: http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=200920100AB2514

[64] SCE CCA-Info Schedule: https://www.sce.com/NR/sc3/tm2/pdf/CE274.pdf.
PG&E CCA-Info Schedule https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_SCHEDS_E-CCAINFO.pdf

[65] SCE Customer Load Profiles: https://www.sce.com/wps/portal/home/regulatory/load-profiles/!ut/p/b1/04_Sj9CPykssy0xPLMnMz0vMAfGjzOK9PF0cDd1NjDzdzb1cDBwDXMxdQoPMDE28DYEKIoEKDHAARwNC-r2IsMCoyNfZN10_qiCxJEM3My8tXz8iJz8xRbegKD8tMye1WD9cPwpsjkW7gauHl7-Bp3tIoLGBp3GggV-wo6OxgYEZVAEedxbkRlT5pAV7AgDTIhZr/dl4/d5/L2dBISEvZ0FBIS9nQSEh/ .

[66] Refer to Note 13.

[67] SVCE Implementation Plan:
https://www.svcleanenergy.org/files/managed/Document/376/SVCEA%20CCA%20Implementation%20Plan%20071416%20%20NO%20Appendices.pdf
Refer to Note 30.

[68] https://www.eia.gov/electricity/data/eia861m/index.html

[69] Southern California Edison, 2014 Corporate Responsibility Report, page 3: 88,986 Million Kilowatt-Hours Total Electricity Sales. SCE Source: https://www.sce.com/wps/wcm/connect/fb423d8a-82df-458f-80ad-916166da17d7/2014_Corporate_Responsibility_Report_WCAG.pdf?MOD=AJPERES

PG&E, 2014 Retail Electricity Sales 74,547 (GWH) - Excludes sales to DA and CCA customers and sales to railroads and railways. PG&E Source: http://www.pgecorp.com/corp_responsibility/reports/2015/bu01_pge_overview.jsp

[70] EIA Form 861: https://www.eia.gov/electricity/data/eia861/

[71] http://www.energy.ca.gov/2014publications/CEC-200-2014-009/CEC-200-2014-009-SD.pdf

[72] Distributed Energy Resources are also defined as generation or storage resources that may be interconnected with the IOU distribution network and may be under the direct operational control of the IOU or an ESP. For purposes of this Study, DER is referred to as “behind the meter” because its operation will impact the Central Coast Power retail sales and thus revenue forecasts.

[73] California Distributed Generation Statistics Currently Interconnected Data Set (3/10/2017):
http://www.californiadgstats.ca.gov/

[74] Though the rebates for the California Solar Initiative have been exhausted and the program is now closed, the California Distributed Generation Statistics website is the official public reporting site of the California Solar Initiative (CSI), is updated monthly, and is presented jointly by the CSI Program Administrators, GRID Alternatives, the California Investor Owned Utilities, and the California Public Utilities Commission.

[75] Refer to Note 48.

[76] Green Tech Media 2016 Solar Report: https://www.greentechmedia.com/articles/read/u.s.-solar-market-has-record-breaking-year-total-market-poised-to-triple-in

[77] National Renewable Energy Laboratory (NREL) PVWatts® Calculator http://pvwatts.nrel.gov/

[78] Note that the Average of Load Served by LSE line displays more load than in Figure 12 because this section is utilizing the Bundled+ Direct Access (DA) figures. The Monte Carlo simulation, into which the load and DER forecasts were built, utilized the Bundled+DA dataset, while DA customer load was backed out in the pro forma analysis.

[79] For purposes of this Study, utility scale renewable generation output is predictable within +/- 6%. North American Electric Reliability Corporation Variable Generation Power Forecasting for Operations: http://www.nerc.com/files/Varialbe%20Generationn%20Power%20Forecasting%20for%20Operations.pdf

[80] In California, capacity requirements are managed through resource adequacy requirements.

[81] Green Tech Media - Congress Passes Tax Credits for Solar and Wind: https://www.greentechmedia.com/articles/read/breaking-house-passes-1.1-trillion-spending-bill-with-renewable-energy-tax

[82] Refer to Note 41.

[83] Refer to Note 5.

[84] However, if the NEM customer exceeds their annual usage with DER output, that excess is eligible to provide Renewable Energy Credits (RECs) to the utility. Refer to Note 48.

[85] California Energy Commission: RPS Eligibility Guidebook, Ninth Edition Revised, January 2017 - http://docketpublic.energy.ca.gov/PublicDocuments/16-RPS-01/TN217317_20170427T142045_RPS_Eligibility_Guidebook_Ninth_Edition_Revised.pdf

[86] California ISO – The ISO Grid: https://www.caiso.com/about/Pages/OurBusiness/The-ISO-grid.aspx

[87] Refer to Note 36.

[88] Refer to Note 36.

[89] CPUC 33% RPS Compliance Filings: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5775

[90] Refer to Note 77.

[91] Power Purchase Agreement Checklist for State and Local Governments https://financere.nrel.gov/finance/content/power-purchase-agreement-checklist-state-and-local-governments

[92] The no/low up-front cost advantage assumes a solid credit capacity. Depending on how the CCA is formed, some credit capability may need to be extended to the CCA entity in order to actually participate in PPA as well as CAISO markets.

[93] Note that the CPUC has implemented a Demand Response Auction Mechanism procuring RA capacity from demand response resources after bifurcation of resources into “load modifying” and “supply side” demand response.

[94] CPUC *2013–2014 Resource Adequacy Report,* August 2015: www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6325. Subsequent to this Study analysis an updated *CPUC 2015 Resource Adequacy Report was released in* January 2017: https://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf

[95] Recent activity with respect to Diablo Canyon has made resource adequacy a major cost variable in the Region. In 2016, Southern California Edison tendered a request for offers for distributed energy resources as a way to strengthen the resilience of the electric grid in South Santa Barbara County. That RFO has since been rescinded. The uncertainty associated with the cost of resource adequacy in the Region must be considered in the holistic view of CCA risks.

[96] CPUC Order Instituting Rulemaking R.10-12-007 Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/128658.htm

[97]CPUC Energy Storage Overview: http://www.cpuc.ca.gov/General.aspx?id=3462

[98] How Cheap Can Energy Storage Get? October 14, 2015, by Ramez Naam: Reference Price of Battery Storage per kWh round-tripped with 15% Learning Rate for $0.18 per kWh starting in 2020. http://rameznaam.com/2015/10/14/how-cheap-can-energy-storage-get/

[99] MCE Deep Green Enrollment: https://www.mcecleanenergy.org/dg-enroll/

[100] EIA California Natural Gas Price Sold to Electric Power Customers: http://www.eia.gov/opendata/qb.php?sdid=NG.N3045CA3.M
How Natural Gas is Measured http://www.tulsagastech.com/measure.html

[101] CEC 2015 Update of the Thermal Efficiency of Gas-Fired Generation in California: http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf

[102] CAISO Market Performance Metric Catalog: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AF1E04BD-C7CE-4DCB-90D2-F2ED2EE8F6E9

[103] Market Performance Metric Catalog for September 2016: https://www.caiso.com/Documents/MarketPerformanceMetricCatalogforSep2016.pdf

[104] Price of Natural Gas Sold to California Electric Utilities: https://www.eia.gov/dnav/ng/hist/n3045ca3m.htm

[105] Time Magazine, Polar Vortex Sends Natural Gas Prices on Rollercoaster - But prices should stabilize in anticipation of warmer weather, Jan. 07, 2014: http://science.time.com/2014/01/07/polar-vortex-sends-natural-gas-prices-on-rollercoaster/

[106] NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016 https://www.nrel.gov/docs/fy16osti/66532.pdf

[107] Refer to Note 2.

[108] CEC Renewables Portfolio Standard Reports and Notices from Publicly Owned Utilities: http://www.energy.ca.gov/portfolio/rps_pou_reports.html;
Refer to Note 2.

[109] The basis of the renewable RPS cost analysis included data from the May 2016: Report on 2015 Renewable Procurement Costs in Compliance with Senate Bill 836 (Padilla, 2011) http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Padilla%20Report%202016%20-Final%20-%20Print.pdf; Subsequent to the analysis an updated report was produced and the data was consistent with the forecast analysis previously performed: May 2017: Report on 2016 Renewable Procurement Costs in Compliance with Senate Bill 836 (Padilla, 2011) http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/Final%20-%20Padilla%20Report%20-%20RPS%20Costs%202017.pdf

[110] When asked about the difference in prices, the CPUC staff replied "There is a very simple explanation for the difference between the prices on p. 8 and the language on p. 20. Specifically, RPS contracts typically don't come online for 3-10 years, so while the prices of contracts approved by the CPUC have declined between 2003 to 2014 (in terms of real dollars) the savings from these less expensive RPS contracts won't be realized until 2017-2020 when lower priced contracts from 2012-2015 come online. The table on p. 8 displays the actual procurement expenditures for 2011-2014, i.e., the payment made on RPS contracts that were executed between 2003-2010."

[111] CPUC Electric and Gas Utility Cost Report, April 2016: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/AB67_Leg_Report_3-28.pdf, pg. 23-24

[112] 2016 Padilla Report:
http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Padilla%20Report%202016%20-Final%20-%20Print.pdf

[113] L.A. Times "*California invested heavily in solar power. Now there's so much that other states are sometimes paid to take it*" by Ivan Penn, JUNE 22, 2017: http://www.latimes.com/projects/la-fi-electricity-solar/

[114] CPUC RPS Reports, Presentations and Charts http://www.cpuc.ca.gov/RPS_Reports_Docs/ ; Biennial RPS Program Update In Compliance with Public Utilities Code Section 913.6, January, 2016
http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=8323
Refer to Note 114.

[115] Refer to Note 3.

[116] Line losses occur as energy is transported across long distances, or as the electricity is stepped down from high voltage transmission lines to lower-voltages utilized in local distribution networks. Congestion in the transmission infrastructure can occur when lines are operating at or near their thermal limits, which can decrease their efficiency. For more information, see *Power Grid Congestion*: http://www.electricity-today.com/overhead-td/power-grid-congestion

[117] California ISO Market price maps: http://www.caiso.com/pages/pricemaps.aspx

[118] California ISO Open Access Same-time Information System (OASIS) http://oasis.caiso.com/mrioasis

[119] Ibid

[120] CAISO Flexible Ramping Product: https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

[121] Energy storage and distributed energy resources: https://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_AggregatedDistributedEnergyResources.aspx

[122] CAISO Demand Response initiative: https://www.caiso.com/1893/1893e350393b0.html

[123] CAISO Renewables Watch: http://www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx

[124] The minimum demand in any given month is considered the "base" for this depiction.

[125] National Renewable Energy Laboratory (NREL) Land-Use Requirements for Solar Power Plants in the United States: https://www.nrel.gov/docs/fy13osti/56290.pdf

[126] U.S. Department of Energy WindVision: A New Era for Wind Power in the United States - https://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf

[127] SCE Tehachapi Renewable Transmission Project - https://www.sce.com/trtp

[128] Transmission Hub, California regulators approve SCE cost recovery prior to Tehachapi undergrounding, 02/28/2013 - http://www.transmissionhub.com/articles/2013/02/california-regulators-approve-sce-cost-recovery-prior-to-tehachapi-undergrounding.html

[129] SDG&E Sunrise Powerlink: http://www.sdge.com/key-initiatives/sunrise-powerlink

[130] SDG&E Sunrise Powerlink Transmission Line Project Fact Sheet: http://regarchive.sdge.com/sunrisepowerlink/docs/srpl_whitepaper.pdf

[131] SDG&E Transmission System Overview Interconnection Information and Map: http://www.sdge.com/generation-interconnections/interconnection-information-and-map

[132] Utility Annual Power Content Labels 2011: http://www.energy.ca.gov/pcl/labels/2011_index.html

[133] Decommissioning San Onofre: http://www.songscommunity.com/
Refer to Note 4.

[134] Distributed Generation Interconnection Collaborative (DGIC), "Minimum Day Time Load Calculation and Screening," April 30, 2014: https://energy.gov/sites/prod/files/Hawaiian%20Electric%202014-04-30_minimum-day-time-load-calculation-and-screening.pdf

[135] Investor-Owned Utility Solar Photovoltaic (PV) Programs: http://cpuc.ca.gov/RPS_SPVP/

[136] CPUC Decision 16-06-044 Granting Petition for Modification and to Terminate the Solar Photovoltaic Program: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K022/164022163.PDF

[137] The term rate proxy is used to emphasize that the Study did not design CCA program rates. Rather, the Study identifies the unitized CCA program revenue requirement or cost to serve by customer class and uses this value as a rate proxy based on COS assumptions. Actual CCA program rates have not been designed as part of this Study.

[138] This 15% is in addition to DA loads that have been excluded from potential CCA load.

[139] IMPLAN Group LLC's Input-Output (I/O) model is the industry standard quantitative economic methodology for calculating interdependencies between industries in local and regional economies.

[140] The Jobs and Economic Development Impact (JEDI) models are industry standard modeling tools that estimate the economic impacts of constructing and operating power generation and biofuel plants at the local and state levels. JEDI analyzes biofuels, coal, concentrating solar power, geothermal, marine and hydrokinetic power, natural gas, and photovoltaic power plants. "Assessment of the Value, Impact, and Validity of the Jobs and Economic Development Impacts (JEDI) Suite of Models," https://www.nrel.gov/docs/fy13osti/56390.pdf

[141] Although the Levelized Cost of Energy for geothermal is comparable to offshore wind, it is 1.6 to 2.5 times greater than that for utility scale solar and wind. The capital costs of geothermal are from two to four times greater than utility scale solar and wind. See Lazard LCOE 10.0, 2016: https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf

[142] Based on 2016 labor data from:
https://slochamber.org/wp-content/uploads/2016/05/6-Uniquely-SLO-WDB.EVC-2016.2v1.pdf
http://www.labormarketinfo.edd.ca.gov/file/indproj/vent$_highlights.pdf
http://www.sbcag.org/uploads/2/4/5/4/24540302/santa_barbara_county_employment_characteristics_ppoint.pdf

[143] This Study was conducted by estimating the supply cost for RPS compliant renewable resources. Other utility scale generation resources are also zero emission resources, such as large hydroelectric and nuclear. However, a comparison of CO2 impact would also need to take into account the non-RPS zero emission resources in IOU portfolios (primarily large hydroelectric as SCE and PG&E nuclear generation stations are being decommissioned). Additionally, the recent rainfall in California has made the existing large hydroelectric generation facilities owned by the IOUs viable again (at least in the near term) and the effect would likely reduce the IOU CO2 emissions for 2017 and as long as non-drought conditions continue.

[144] EIA - Carbon dioxide is produced per kilowatthour when generating electricity: http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11

[145] CEC Quarterly Fuels and Energy Report (QFER) CEC-1304 Power Plant Data Reporting - Thermal Efficiency of Gas-Fired Generation in California: 2015 Update: http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf

[146] The emissions attributable to CO_2 in California (568.6 pounds per MWh) represent 99.68% of the total output emission rate (570.5 pounds per MWh). Therefore, CO_2 was considered instead of CO_2 equivalent. https://www.epa.gov/sites/production/files/2017-02/egrid2014_summarytables_v2.xlsx

[147] Refer to Note 41.

[148] It is assumed that DA-customer ESPs would also comply with RPS requirements. However, for the purposes of this Study, it is assumed that DA customers opt out of CCA service.

[149] Schedule CCA Transportation of Electric Power For Community Choice Aggregation Customers: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CCA.pdf

[150] SCE Direct Access & Community Choice Aggregation Operations information including Distribution Line Loss Factors: http://bit.ly/2DA-CCA-Ops

[151] CPUC Actions to Limit Utility Cost and Rate Increases, Public Utilities Code Section 913.1 Report: http://www.cpuc.ca.gov/uploadedfiles/cpuc_website/content/utilities_and_industries/energy/reports_and_white_papers/cpuc%202016%20section%20913-1%20and%20sb695%20leg%20report.pdf
ACEEE whitepaper: Decoupling Mechanisms: Energy Efficiency Policy Impacts and Regulatory Implementation: http://aceee.org/files/proceedings/2006/data/papers/SS06_Panel5_Paper29.pdf

[152] Marin Energy Authority (MEA aka MCE); refer to Note 24.

[153] CPUC Energy Efficiency Program Administrators: http://www.cpuc.ca.gov/General.aspx?id=4460

[154] California Community Choice Association: http://cal-cca.org/

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