CITY OF **SAN DIEGO**

FEASIBILITY STUDY FOR A COMMUNITY CHOICE AGGREGATE

JULY 2017 | FINAL DRAFT

APPENDICES

WILLDAN FINANCIAL SERVICES | EnerNex

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GLOSSARY & LIST OF ACRONYMS

This section has been reproduced from the main report for the assistance of the reader. However, terms and acronyms used only in the Appendices may not appear in this list. Not all terms appearing in this list are used in the Appendices.

A

AB	Assembly Bill

B

Baseline	Load allowance used in rate tariffs for San Diego Gas and Electric; refer to Special Condition 3, Sheet 5: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DR.pdf
Baseload	The portion of CCA program customers receiving the basic power supply portfolio based on the specific renewable content scenario: 50% for the Base Case Scenario and Scenario 2, 80% for Scenarios 3 and 5, and 100% for Scenario 4.
Bundled Customers	Customers receiving generation, transmission, and distribution services from the incumbent utility.

C

CA	California
CAISO	California Independent System Operator
CalCCA	California Community Choice Association
CAP	City of San Diego Climate Action Plan, Adopted by the City Council on December 15, 2015 by Resolution Number: R-2016-309, Amended by the City Council on July 12, 2016 by Resolution Number R-2016-762 https://www.sandiego.gov/sustainability/climate-action-plan
CARE	California Alternative Rates for Energy
CCA	Community Choice Aggregation
CEC	California Energy Commission
CI	Confidence Interval
City	City of San Diego
COS	Cost of Service
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CRS	Cost Responsibility Surcharge
CTC	Competitive Transition Charge

D

DA	Direct Access—customers receiving energy from an alternative non-Investor Owned Utility supplier.
DAM	Day Ahead Market
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
DWR-BC	Department of Water Resources Bond Charge

E

EDI	Electronic Data Interchange
EE	Energy Efficiency
EIA	Energy Information Administration
EnerNex	EnerNex LLC, consultant retained by the City for purposes of this Study
EPRI	Electric Power Research Institute
ESP	Electric Service Provider excluding Investor Owned Utilities

F

FTE	Full Time Equivalent

G

GHG	Greenhouse Gas
GWh	Gigawatt Hour

I

IMPLAN I/O	IMPLAN Group LLC's Input-Output Multiplier Model
IOU	Investor Owned Utility

J

JEDI	National Renewable Energy Laboratory Jobs and Economic Development Impact Model
JPA	Joint Powers Authority

K

kW	Kilowatts
kWh	Kilowatt Hours

L

LCE	Lancaster Choice Energy
LMP	Locational Marginal Prices
LSE	Load Serving Entity, including Investor Owned Utilities, Electric Service Providers, and CCA programs.
LTPP	Long Term Procurement Plan

M

MMBTU	Million British Thermal Units
MCE	MCE Clean Energy formerly Marin Clean Energy
MCSM	Monte Carlo Simulation Model
MEA	Marin Energy Authority, formed through a Joint Powers Agreement among municipalities which later established MCE Clean Energy
MMT	Millions of Metric Tons
MW	Megawatts, represents power or capacity or demand
MWh	Megawatt Hours, represents electric energy

N

NPV	Net Present Value
NREL	National Renewable Energy Laboratory

O

OASIS	Open Access Same-time Information System
Opt Out	The portion of customers declining to join the Community Choice Aggregation program. Also referred to as opt-out.
Opt Up	The portion of CCA customers selecting 100% renewable portfolio content energy.

P

PCIA	Power Charge Indifference Adjustment
Period	CCA fifteen-year timeline evaluated in the study from 2020 through 2035.
PEV	Plug-in Electric Vehicle
PG&E	Pacific Gas & Electric
POC Report	*Community Choice Energy in the City of San Diego: An Initial Assessment of Program Prospects*, prepared by Protect Our Communities Foundation, September 25, 2015.
PPA	Purchase Power Agreement
PV	Photovoltaic

R

RA	Resource Adequacy
REC	Renewable Energy Certificate or Credit
RPC	Renewable Portfolio Content
RPS	Renewable Portfolio Standard
RTM	Real Time Market

S

SCE	Southern California Edison
Scenarios	Analyses defined for the feasibility study based on levels of renewable energy content in the CCA portfolio: Base Case - 50% renewables for base load customers and 2% opting up to 100% renewable content; Scenario 2 – 50% renewable content for all customers; Scenario 3 – 80% renewable content for all customers; Scenario 4 – 100% renewable content for all customers; and Scenario 5 - 80% renewables for base load customers and 2% opting up to 100% renewable content.
SDG&E	San Diego Gas & Electric, made up of bundled service customers
SEAB	City of San Diego Sustainable Energy Advisory Board
Sensitivity Analyses	What-if evaluation of the impact on study results based on changes in the base assumptions: Sensitivity 1 – 6% increase in SDG&E rates; Sensitivity 2 – 2% decrease in SDG&E rates; Sensitivity 3 – 10% increase in Power Charge Indifference Adjustment; Sensitivity 4 – 2.5 % decrease in Power Charge Indifference Adjustment; Sensitivity 5 – 25% Opt Out Rate, Sensitivity 6 – 15% Opt Out Rate.
State	The State of California
Study	This City of San Diego Community Choice Aggregate Feasibility Study, Final Draft, July 2017.
Study Team	Collectively Willdan Financial Services and EnerNex LLC, consultants retained by the City for purposes of this Study

T

TOU	Time-of-Use

U

UDC	Utility Distribution Company

W

Willdan	Willdan Financial Services, consultant retained by the City for purposes of this Study

APPENDIX A

COMMUNITY CHOICE ENERGY IN THE
CITY OF SAN DIEGO: AN INITIAL ASSESSMENT
OF PROGRAM PROSPECTS

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Protect Our Communities Foundation

City of San Diego

Community Choice Assessment

September 2015

Community Choice Energy In the City of San Diego: An Initial Assessment of Program Prospects

Prepared for the City of San Diego
by Protect Our Communities Foundation

September 25, 2015

Background and Scope of Report

The Protect Our Communities Foundation (POC) submits this report to the City of San Diego with technical appendices provided by Community Choice Partners, Inc. (CCPartners). The report provides a summary of initial economic modeling and analysis for feasibility of a Community Choice Aggregation (CCA) program in San Diego along with relevant background information regarding CCA programs in California.

POC is a 501(c)(3) nonprofit organization incorporated in the State of California with a mission to defend communities and the natural environment in San Diego County, Imperial County, and northern Baja California and advance energy and environmental solutions through advocacy and law.

POC initiated a study of a CCA program for San Diego in early 2014 to assess the prospects for CCA development in the region. POC engaged CCPartners to draft a feasibility study. To facilitate the study, the Mayor of San Diego requested and received relevant customer usage data from San Diego Gas and Electric Company (SDG&E). Pursuant to a contract between CCPartners and the City, the data was provided to CCPartners for its analysis of customer load patterns and the development of an analysis to determine whether consumer energy rates through CCA could be competitive.

CCPartners did not submit a full feasibility study to POC. However, in June 2015, CCPartners presented POC and the City with a “pro forma” analytical model that may be used to evaluate financial viability and consumer rates at various program sizes, utilizing multiple cost and load assumptions. CCPartners also provided two model results with different assumptions about program design.

As an advocacy organization, POC has supported CCA development in the San Diego region and believes that successful experiences of CCAs in California to date support an optimistic view of CCA implementation in other California communities. The intent of this report, however, is to provide a preliminary feasibility assessment for a potential CCA program in the City of San Diego, with the recommendation that the City conduct additional and more in-depth analysis as a practical next step.

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Appendices

1.0 Executive Summary

This report provides a summary of initial economic modeling and analysis of the feasibility of a Community Choice Aggregation (CCA) program in the City of San Diego, also known as "Community Choice Energy." CCA programs permit local governments to purchase and develop energy resources on behalf of local residents and businesses as an alternative to service from the incumbent investor-owned utility. Three CCAs are currently operational in California.Dozens of other local governments throughout the state are exploring CCA as a strategy to achieve multiple goals, including to provide broader consumer choice and achieve renewable energy targets set forth in local Climate Action Plans.

The prospects for CCA programs in California have improved significantly in recent years as a result of a number of factors:

- The success of Marin Clean Energy and Sonoma Clean Power in terms of financial viability and meeting or exceeding public policy objectives;
- Favorable wholesale energy market conditions and relatively low-cost power;
- Recognition that a CCA program can be a self-supporting option for meeting Climate Action Plan objectives and other public policy goals;
- Reduced cost of renewable power and improvements in renewable technologies;
- The development of expertise, best practices, and an expanded vendor base to serve CCA programs.

Existing CCA programs in California – Marin Clean Energy (MCE), Sonoma Clean Power (SCP) and Lancaster Choice Energy (LCE) – have been successful in procuring cleaner power at lower electricity rates, providing innovative services, and supporting local economies with new energy programs and projects. With somewhat different business strategies, California's operational CCAs have so far demonstrated the viability of CCA programs and motivated dozens of California jurisdictions to investigate the prospects for CCA programs. That said, CCA programs are not without risks. The success of a CCA depends on strong management, appropriately hedged supply portfolios and community support.

The initial analysis summarized in this report was performed by Community Choice Partners Inc. (CCPartners). The analysis indicates favorable financial performance for a City of San Diego CCA given reasonable assumptions about program design, utility rates, market prices and other factors. It also identifies a challenge that would need special consideration, namely, the impact on customer rates resulting from the "stranded costs" that SDG&E might experience if a large portion of customers within the City of San Diego were to take service from a CCA.

The CCPartners analysis provides some insights about the prospects for CCA in San Diego, but is neither comprehensive nor validated. Although general information about CCA program development, program design, risks, and opportunities is now publicly available, the City will need more analysis that is relevant to its circumstances before making any final decisions.

POC recommends the following if the City of San Diego moves forward with a more in-depth investigation of CCA:

- Engage consultants to:
    - Conduct a validation study of CCPartners's pro forma model by testing its specifications and assumptions
    - Perform a more comprehensive analysis of program design, scenario development and process
    - Analyze ways to mitigate SDG&E stranded costs and associated increases to the Power Charge Indifference Adjustment (PCIA);
- Allocate staff to develop and manage the planning process;
- Allocate funding for program planning and development costs;
- Meet with key stakeholder groups to provide information and solicit initial feedback.

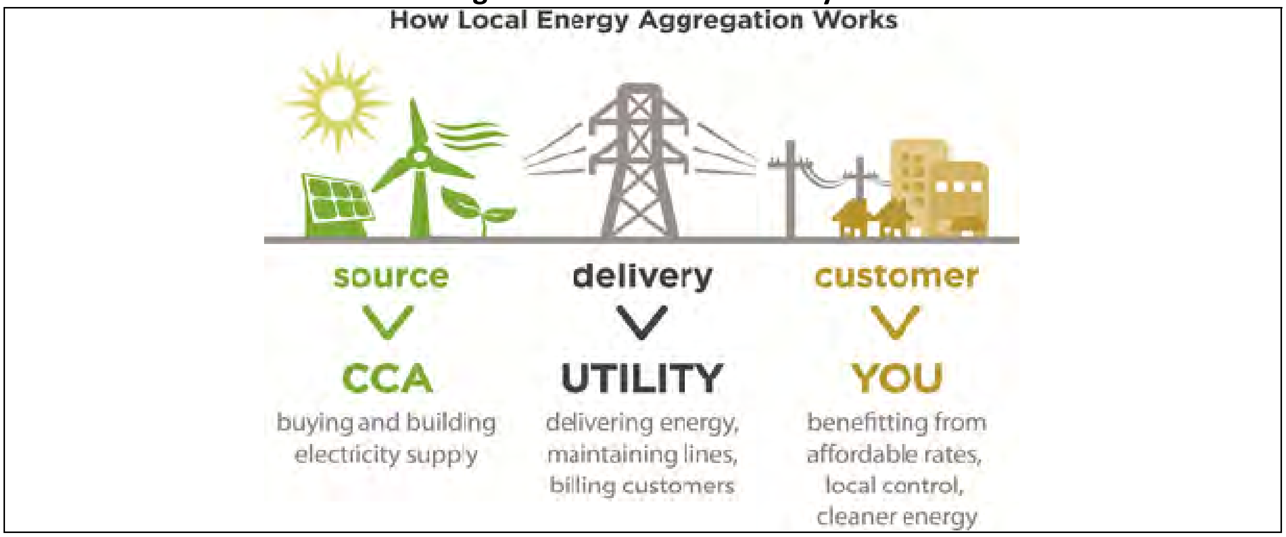
If, on the basis of additional analysis, the City believes it can design a program that will serve community goals and be fiscally sustainable, the City should:

- Engage consultants to support program staff with developing documents, planning processes, analyzing program design options and developing a communications plan;
- Articulate broad program goals and policy objectives as part of formal deliberations on the adoption of a CCA ordinance;
- Develop and implement a plan for community engagement, outreach and dissemination of information;
- Consider whether to appoint an advisory committee that would report to the City Council and Mayor;
- Consider whether to engage other local jurisdictions as part of an analysis regarding whether the City should manage a CCA program within existing city government or as part of a Joint Powers Authority (JPA) that would be able to permit participation by other local communities.

2.0 Introduction to CCA

The California Legislature passed AB 117 in 2002 authorizing local jurisdictions to develop CCA programs that would provide electricity services to local residents and businesses.[1] CCA programs enable local governments to determine the mix of generation resources and related energy services on behalf of the community. They are distinct from municipal utilities, which typically own and manage distribution facilities. CCA customers remain customers of the incumbent utility for distribution and transmission services, as shown in Figure 1. Customers experience no difference in their energy delivery or billing process.

Figure 1: CCA Power Delivery



(Graphic courtesy of LEAN Energy US)

State law also provides that:

- Local governments may create CCA programs with the adoption of an ordinance by the governing body;
- CCA is an "opt-out" program – customers are automatically enrolled in CCA services but may choose to remain with the incumbent utility or return to utility service at any time and they may choose to opt-out for some accounts and not others;
- CCAs must ultimately offer service to all residential customers;
- CCAs are subject to the same energy resource policies that apply to the state's "load serving entities," including requirements for renewable portfolio content, resource adequacy, energy storage and reporting;

[1] **Appendix A** is a Glossary of Terms for terminology used throughout this report. **Appendix B** is a basic fact sheet about CCA and how it works.

- CCA customers must pay a monthly fee called the Power Charge Indifference Adjustment (PCIA) to assure that customers who remain with the utility are cost-indifferent to the CCA serving former utility customers. The CCA must account for this "exit fee"(also known as a non-bypassable charge) when designing its own rates. Although they are not considered regulated public utilities, CCAs are subject to certain rules and oversight by the California Public Utilities Commission (CPUC);
- CCAs are entitled access to utility data regarding customer load by customer class.

3.0 CCA Program Opportunities and Challenges

CCA programs offer a number of potential benefits for local communities:

- **Consumer Choice**. CCA programs give consumers an opportunity to choose from among energy providers. The competition may also spur innovation and a greater variety of consumer oriented services.
- **Revenues for Local Economic Development**. Revenues from CCA programs remain in the community, supporting the local economy and jobs. CCA agencies can finance local energy projects with tax-exempt bonds and do not have to pay shareholder dividends or large management salaries, resulting in lower costs and rates.
- **Environmental Benefits**. Local governments can use CCA programs to increase community reliance on energy supplies with lower greenhouse gas (GHG) emissions. Many local climate action plans have stressed that a major source of GHG is from power plants that serve the area's population, and suggest CCA programs can support progress toward climate action goals.
- **New Local Energy Programs**. CCA programs can implement energy initiatives, such as energy efficiency and demand response programs that serve specific community goals. CCAs may also qualify for substantial funding for such programs from the CPUC.
- **Rate Stability and Lower Prices**. Because CCAs are not profit-driven, they can promote strategies, such as demand reduction, that lead to lower and more stable rates over the long term.
- **Local Control of Energy Planning and Pricing.** CCAs are either public agencies or programs of public agencies with authority to set rates and make decisions about energy services to their customers. As local agencies of government, they are closer to the local public and subject to state laws regarding open processes and transparency. Accordingly, they are more likely to be responsive to local needs and community objectives.

CCA programs also face risks. California law is unclear with regard to the extent to which local governments may be responsible for CCA liabilities. The main risks associated with CCA include:

- **Market Price Fluctuations**. California's energy markets have been stable for several years, and prices are low. The current buyer's market is expected to continue for the coming several years because California has excess energy supplies. However, energy markets could change. California law now requires CCAs to hedge their risks by purchasing long term supplies for 65 percent of their supply portfolios by 2021, which could result in higher prices for renewable energy.

- **Regulatory Risk**. In recent years, the CPUC has adopted some proposals for rates and services that have not been favorable to CCAs. Subsequently, regulatory participation by CCAs is essential and must be accounted for as a necessary cost.

- **Operational and Management Risk.** CCA programs operate in complex energy markets and are subject to complicated regulatory requirements. CCA success depends on realistic business strategies and sound management.

- **Community Outreach and Communication Challenges**. Experience in other jurisdictions suggests CCA development and implementation will require communications strategies to assure the program is accepted by local communities and that program design aligns with community goals and expectations. Even with a solid communications strategy, CCA development may meet with opposition. Since passage of SB 790 in 2011, anti-CCA marketing has subsided to some extent as California statute prohibits utilities from marketing against CCA development.

4.0 CCA Programs in California

Currently, California has three operating CCAs, two of which have demonstrated financial viability, achieved environmental objectives, and provided new services to customers (the third began operation in May 2015).

The State's first CCA, Marin Clean Energy, launched in 2010 by serving a portion of Marin County residents and businesses. Today, it serves all of Marin County and unincorporated Napa County, as well as the cities of El Cerrito, Richmond, Benicia, and San Pablo. MCE has purchased electricity from the state's wholesale market and from local renewable projects.

Sonoma's CCA, Sonoma Clean Power, launched in May 2014 and currently serves all of Sonoma County. It has plans for developing about 90 MW of new renewable power supplies in its service area in partnership with private developers.

The City of Lancaster launched Lancaster Choice Energy (LCE) in May 2015 and plans to purchase power from local solar projects, including a 20-year power-purchase agreement with sPower recently approved by the Lancaster City Council from the Western Antelope Dry Ranch project priced at about $55/MWh. Additionally, LCE has announced plans for a large-scale energy storage project to support greater utilization of locally-supplied solar energy.

Both MCE and SCP are providing energy-related services such as energy efficiency retrofits, on-line energy usage monitoring, community electric vehicle charging stations, on-bill financing, and energy storage. MCE and SCP offer customers a 100 percent clean power option sourced from local renewable resources. SCP and MCE have so far been successful financially, with solid reserves after making substantial investments in the local community and offering services not provided by the incumbent utility.

MCE and SCP were established at the county level and are each governed by a Joint Powers Authority (JPA), which gives them flexibility to add new communities and protects their local jurisdictions from operational and market risk. LCE is a program of city government. Table 1 summarizes the program elements in California's three operational CCAs. More information about these CCAs' rates, services, financials and greenhouse gas impacts are included in **Appendices C and D**.

Table 1. Summary of Program Elements - Operational California CCAs

	Marin Clean Energy (2010)	Sonoma Clean Power (2014)	Lancaster Choice Energy (2015)
Customers	165,000 by end of 12/15	~200,000	56,000 by 10/15
Opt-Out Rate	22 percent	11 percent	TBD
FY 2015-16 Budgets	$145,933,097	$165,495,000	$25,000,000
Service Area	All Marin County; cities of Richmond, San Pablo, El Cerrito, Benicia, and unincorporated Napa Co.	All Sonoma County and Sonoma County cities	City of Lancaster
Percentage RPS Qualified	50 percent minimum with opt-up to 100 percent	33 percent minimum with opt-up to 100 percent	35 percent minimum with opt-up to 100 percent
2015 Generation Rates	On average, 3-7 percent lower than PG&E	On average, 6-9 percent lower than PG&E; 10-14 percent less for low income customers	On average, 3 percent lower than Southern California Edison (SCE)

The success of MCE and SCP has motivated many other California communities to investigate CCA programs, as shown in Figure 2. Currently, more than 20 counties representing hundreds of cites are investigating or actively pursuing CCA formation. The County of San Mateo and the City of San Francisco are among the jurisdictions that are currently planning to launch services in 2016.

Figure 2. California Political Jurisdictions with Operational CCAs or that Are Evaluating CCA

(Chart courtesy of LEAN Energy US, dated May 2015)

5.0 The Results of the CCPartners Pro Forma

The CCPartners pro forma provides a snapshot of the financial viability of a City of San Diego CCA program based on certain strategies and using specific assumptions. The modeling conducted by CCPartners for POC analyzes a City of San Diego CCA program in its first three years of operation with the following program strategies:

- Initial program launch in April 2016;
- Initial service offered to 45 percent of residential and medium commercial customers, and 100 percent of all other commercial customers;
- A supply portfolio comprised of 33 percent renewable energy resources with no unbundled "RECs";
- A net energy metering program that pays $.01 more than retail for local renewable energy supplies;
- $3 million allocated to CCA programs such as energy efficiency, demand response or feed in tariffs;
- Customer generation rates that are 5 percent lower than SDG&E's, net of the PCIA exit fee.

According to CCPartners, the model includes the following assumptions:

- First year program costs of $9 million for management costs, consulting fees, regulatory compliance and customer outreach, a cost higher than reported results for MCE and SCP;
- A PCIA “exit fee” (non-bypassable charge) of $.01/kWh, based on SDG&E’s methodology for calculating the PCIA (and higher than the current tariffed rate of $.008/kWh);
- Wholesale energy prices that are consistent with the 2015 market forecasts of the California Energy Commission;
- Customer demand of approximately 2,600 gigawatt-hours (GWh) in the first year, growing to about 3,400 GWh in the second and third years;
- Customer load profiles that are derived from and consistent with 2013 SDG&E-supplied customer data for 2013;
- SDG&E generation rate increases according to an escalator from E3’s GHG calculator;
- A 20 percent “opt-out” rate, higher than either of the actual opt-out rates in MCE or SCP;
- First year financing for energy purchases and other costs of approximately $50 million with full repayment within 12 months.

Using these assumptions, the CCPartners pro forma suggests the City’s CCA could offer generation rates at a 5 percent discount with a product offering that is comparable to SDG&E’s existing renewable energy portfolio, with the modeled portfolio achieving the state’s Renewable Portfolio Standard (RPS) 2020 requirements in the CCA’s second year of operation.

The pro forma results suggest the City would have substantial funds for local energy programs and an adequate reserve at the end of the first year after paying off first year debt. Specifically, the pro forma shows a fund balance of about $60 million on gross revenues of approximately $222 million. The fund balance would increase to about $176 million by the third year, assuming no additional investment in local energy projects or programs. The CCPartners spreadsheet analysis is provided in **Appendix E**.

CCPartners also analyzed the financials assuming service to all commercial customers but no residential customers in the first three years. The results are slightly more advantageous, with a 10 percent rate discount and a fund balance of $206 million by the third year. This program design would need to be short-term because of California’s statutory requirement that the CCA offer service to all residential customers. Although the law does not provide a timeline for the service, the City would likely consider including some residential customers in the first three years of the program to maintain broad public support.

While a comprehensive review of CCPartners modeling results has not been conducted by POC, the CCPartners financial projections appear to rely on reasonable assumptions. For example, the opt-out rate is conservative as it is higher than actual opt-out rates in operational CCA jurisdictions. The SDG&E rate assumptions and market prices appear to be based on accepted forecasts.

The first year margin of about 27 percent is higher than actual margins of existing CCAs, which have so far been less than 15 percent. However, the lower MCE and SCP results might be expected since: (1) both CCAs have a higher proportion of more expensive renewable content in their portfolios than assumed in the CCPartners analysis for San Diego's program, (2) both CCAs have made proportionately larger investments in local energy programs and projects that would have the effect of reducing their respective fund balances, and (3) SDG&E has the highest generation rates of any IOU in California, while wholesale market and forward prices for the region are significantly lower than these rates.

The model assumes a launch date of April 2016. This is not realistic and was not realistic at the time of the model run in June 2015. However, the April 2016 launch date was chosen so that the model would provide an "apples to apples" generation rate comparison with SDG&E under current market conditions. A model run with updated information would undoubtedly change the outcomes, although it is not obvious in which direction.

6.0 Additional Analysis Needed

The results from the CCPartners model are preliminary and are not comprehensive. Although a high level review of the model suggests both its assumptions and results are reasonable in light of experiences in other jurisdictions, POC has not tested the way the pro forma model calculates outcomes or verified every assumption. As noted, the model would have to be updated closer to when the City plans to launch a CCA.

Additionally the energy landscape is evolving in various ways, such as the RPS target moving above 33 percent, that are not incorporated into the existing model runs.

The pro forma model can estimate rates and financials for different sets of assumptions about program design, market conditions, and other metrics, but POC has not performed model runs with different sets of assumptions. Before making any decisions about whether to proceed with a CCA program, POC advises the City to consider:

- ***Validation of the CCPartners model assumptions*** – The CCPartners pro forma model should be reviewed for the accuracy of every model input and assumption regarding, for example, SDG&E rates, the PCIA, customer load, commodity cost forecasts, congestion and resource adequacy prices, and program costs. All of the models inputs will affect its results;

- ***Validation of the CCPartners model's functionality*** – POC has not tested the way the CCPartners model is specified or its analytical rigor, for example, whether the forecast of the PCIA changes with differing forecasts of load, and whether changed assumptions regarding supply costs will be accurately reflected in net margin;
- ***Scenario Development on program design***: – More analysis is needed regarding program design options and customer phase-in strategies, for example: how a "commercial customer first" program in the first several years might affect financials; the schedule for phase-in of various customer classes and regions, portfolio content, customer services and build-out strategies; and how partnerships with other regional communities might affect program viability;
- ***Sensitivity analysis*** – The CCPartners model should be run for changes in assumptions regarding, for example, SDG&E rates, program design, opt-out rates, market prices, portfolio composition and load by customer class;
- ***Higher renewable energy levels*** – The CCPartners model assumed a 33 percent renewable energy supply portfolio, with no unbundled "RECs," by 2017; based on comparable rates of renewable energy in the region, the City may wish to analyze higher levels of renewable energy supply and various strategies for achieving its targets;
- ***Relevance of 2013 load and customer class data*** – The CCPartners model relies on data from 2013, with average customer usage escalated according to CEC load growth forecasts. Because the City could not expect to launch a program before 2017, the City may wish to update load data for incorporation in any additional analysis.

7.0 Special Considerations in San Diego

The City of San Diego's customers' energy demand represents almost half of SDG&E's total load. This circumstance, which is so far unique for California CCA programs, has implications for the CCA's competitiveness, at least in the near-term. If the City's CCA were to serve all San Diego residents and businesses, SDG&E would have substantial "stranded investments" related to long-term energy supply commitments. Related costs are allocated to the CCA's customers according to state law in the form of an exit fee (non-bypassable charge) to the CCA's customers. The CPUC regulates this exit fee, which the CPUC and utilities refer to as the PCIA. Even though customers pay the utility the PCIA, the impact of the PCIA on CCA customers must be considered in any CCA rate analysis to assure CCA customers do not pay more for CCA service than they would pay for SD&GE service.

CCPartners preliminary analysis suggests that, because of potential increases to the PCIA as it is currently structured, CCA rates may not be competitive with SDG&E's if initial customer enrollment in the CCA is too large without additional regulatory reform related to how the PCIA is calculated.

This threshold may occur when SDG&E loses more than about 3,500 GWh of load to the CCA. This is roughly equal to the amount of energy forecasted to be used in 2016 by 80 percent of all City of San Diego commercial customers. It is also the amount expected to be used in 2016 by 45 percent of the City's residential and medium commercial load, plus 80 percent of the small and large commercial load. This represents a substantial CCA customer base in the first three years of operation.

Not coincidentally, CCPartners modeled initial CCA programs with these characteristics because the associated customer class demand forecasts came in just under the 3,500 GWh threshold.

Because of the potential cost impact of substantial increases to the PCIA if there is a large customer shift in the initial phase, a San Diego CCA could not offer full enrollment at competitive rates to all San Diego customers during the first three years of the program unless the CCA is able to negotiate some cost mitigations or develop PCIA mitigating program design strategies.

This circumstance is a challenge that will require additional analysis and some creative thinking about how to balance SDG&E's obligation to provide reliable electric services and the CCA's need to offer competitive rates. However, it is important to note that the two established CCAs in California, MCE and SCP, have incrementally added customers over time. This same approach would occur with a City of San Diego CCA as the PCIA issue is resolved.

If the City decides to move forward, it should engage both SDG&E and the CPUC in early discussions about how to plan for a transition to full CCA service to all customer categories. For example, the CCA may be able to purchase excess power supplies from SDG&E at cost rather than going out into the wholesale market, which would reduce SDG&E's liability and mitigate increases to the PCIA. In both modeled scenarios, the fund balance by the second year is substantial, which could be used to mitigate PCIA impacts. SDG&E may be able to renegotiate some of its contracts or sell power in wholesale markets to mitigate losses.

CPUC policy already requires that SDG&E develop realistic assumptions about "departing load" in developing its long and medium term power supply strategies. SDG&E and the City may be able to agree on procedures to facilitate good planning, such as a notification process or schedule that provides some assurance to SDG&E regarding its future service obligations.

The City can accommodate this period of transition and mitigate cost impacts by phasing-in customer participation. California law does not specify a timeline for offering service to all residential customers. Any reasonable timeframe may be acceptable, especially if the reason for postponing expansion of the CCA customer base is to protect customers from higher rates in a program that requires customers to affirmatively opt-out.

8.0 Next Steps

If the City of San Diego decides to move ahead with the next stage of CCA investigation, it should:

- Engage consultants to conduct a validation study of CCPartners pro forma model results by testing its specifications and assumptions; perform more comprehensive analysis of program design, scenario development and process; and analyze ways to mitigate SDG&E stranded costs and associated increases to the PCIA;
- Allocate staff to develop and manage the planning process;
- Allocate funding for program planning and development costs;
- Meet with key stakeholder groups to provide information and solicit initial feedback.

If, on the basis of additional analysis, the City believes it can design a CCA program that will serve community goals and be sustainable, the City should:

- Engage consultants to support program staff with developing planning documents, analyzing program design options and developing a communications plan;
- Articulate broad program goals and policy objectives as part of formal deliberations on the adoption of a CCA ordinance;
- Develop and implement a plan for community engagement, outreach and dissemination of information;
- Consider whether to appoint an advisory committee that would report to the City Council and Mayor;
- Consider whether to engage other local jurisdictions as part of an analysis regarding whether the City should manage a CCA program within existing city government or as part of a JPA that would be able to permit participation by other local communities.

APPENDIX A

GLOSSARY OF TERMS

Term	**Meaning**
Behind-the-meter	Refers to energy efficiency or electricity generation that takes place on the customer side of the electricity meter rather than on the utility/grid side.
California Public Utilities Commission (CPUC)	California's State agency in charge of regulating investor-owned utilities.
Community Choice Aggregation (CCA)	The legal term used in AB 117 and by the CPUC for programs herein referred to as Community Choice Energy. As authorized by statute, CCA allows local governments to pool the municipal, residential and commercial electrical load within their municipalit(ies) for the purpose of procuring and developing power on their behalf.
Demand response	Technology that lowers electricity demand (or consumption) in response to shortages in the available supply of electricity.
Direct Access	A program that permits utility customers to purchase power supplies from a provider other than the incumbent utility; CCA programs are not considered direct access
Feed-in tariff	A standard power contract, usually for small projects 1MW or less, that requires the utility to pay a set amount for generated renewable electricity for a set number of years, depending on technology.
Greenhouse gas (GHG)	A gas that causes the atmosphere to trap heat radiating from the earth. The most common GHG is Carbon Dioxide, though Methane and others have this effect.
MWh (megawatt-hour)	A unit of electrical energy that is produced or consumed= to 1,000 kilowatt hours. Thus, 8,000 kwh = 8 MWh.
Implementation Plan	A plan CCAs must present to the CPUC for its certification and review for consistency with state law and CPUC rules
Investor-owned utility	A privately-owned power distribution company, such as Pacific Gas and Electric (PG&E), that in California is regulated by the CPUC.
Joint powers authority (JPA)	An entity permitted under the laws of some states, whereby two or more public authorities (for example, local governments, or special districts) can operate collectively.
Electric Load	The amount of electricity a customer or group of customers uses; also referred to as "demand."
Load-serving entity	A firm or organization that purchases electricity on behalf of any customer or group of customers. Once formed, a CCA is considered a load serving entity.
MW (megawatt)	A unit of electrical power equal to 1 million watts that expresses the capacity (or power rating) of power plants or consuming devices. As a unit of capacity, a MW is distinct from a MWH, which is a unit of electricity. For example, a solar plant with a *capacity* of 1 *MW* will – running at fully capacity – produce a *MWH* of *electricity* in one hour.
Microgrid	A local, small scale power grid that can operate independently of or in conjunction with the central utility system.

Net metering	A state-mandated program through which utility customers with behind-the-meter renewable generating facilities smaller than 1 MW can receive bill credit for power not used on-site and delivered to the grid (causing the meter to run backwards).
PCIA or “exit fee” (nonbypassable charge)	Power Charge Indifference Adjustment (PCIA) is a nonbypassable charge based on stranded costs of utility generation set by the California Public Utilities Commission. It is calculated annually and assessed to customers who take service from an electric generation provider (e.g. CCA) other than the incumbent utility.
Peak load	The electrical power demand at that time, over the course of a year and during the day, when electricity consumption is greatest.
Power Purchase Agreement (PPA)	Term for energy supply contract
Renewable energy certificate (REC)	A certificate of proof that one MWh of electricity was generated and delivered to the grid by an eligible renewable energy resource. A REC can be sold together with the underlying energy or “unbundled,” and sold separately.
Renewable portfolio standard (RPS)	Law that requires CA utilities and other load serving entities (including CCAs) to provide an escalating percentage of CA qualified renewable power (culminating at 33 percent by 2020) in their annual energy portfolio.
Community shared solar	An arrangement by which many electricity customers in a community may each own a portion of a solar PV generating facility, and therefore receive a share of the electricity and/or revenue it generates.
Smart grid	An electricity supply network that uses electronic communications and management systems to respond to changes in system requirements.
Solar PV	A solar electricity generating technology in which solar energy is transformed into electricity through a photovoltaic (PV) effect.
Unbundled RECs	Renewable energy certificates that verify a purchase of a MWH unit of renewable power where the actual power and the certificate are “unbundled” and sold to different buyers.

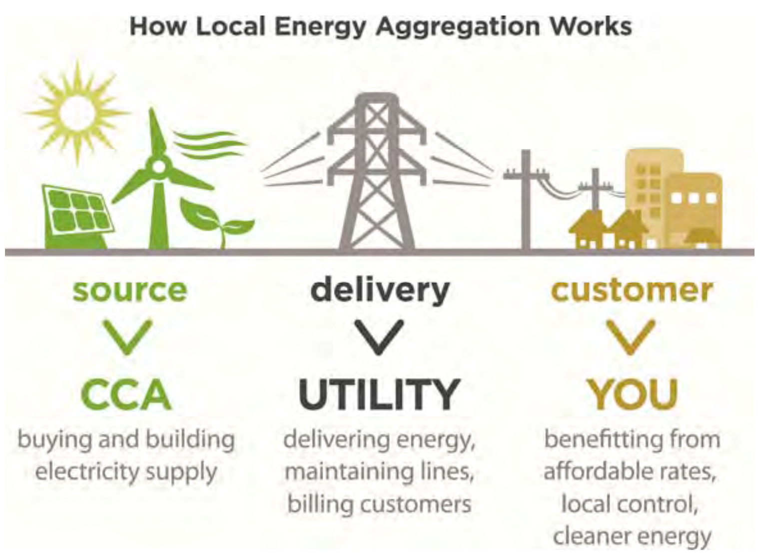
(Courtesy of LEAN Energy US)

APPENDIX B

SAMPLE CCA FAQ SHEET: PREPARED FOR SILICON VALLEY/SANTA CLARA
(*courtesy of LEAN ENERGY US*)

Community Choice Energy (CCA)
Frequently Asked Questions

- **What is Community Choice Energy?** Community Choice Energy (CCA) is a program that enables city and county governments to pool (or aggregate) the electricity demand of their communities for the purpose of supplying electricity. A CCA buys and/or develops power on behalf of the residents, business, and government electricity users in its jurisdiction. The electricity continues to be distributed and delivered over the existing electricity lines by the incumbent utility-which is Pacific Gas and Electric (PG&E) in Northern California.



- **How will CCA be administered in Silicon Valley/Santa Clara County?** The CCA program will be administered by a joint powers agency that serves as a public, non-profit agency on behalf of municipalities that choose to participate in the CCA. It is important to note that through the JPA structure, the assets and liabilities of the JPA remain separate from those of the County or City general funds. Thus, any surplus funds generated by the CCA will be reinvested back into the community in the form of new energy projects and programs and will not flow back into the general funds of the JPA's member jurisdictions.

- **How are CCA's funded?** All CCAs, once they are operational, are completely ratepayer funded and are not subsidized by taxpayer dollars. Ratepayer revenues for electrical generation services currently go to the incumbent utility (PG&E), but would be re-directed to the CCA program which would become the County's default provider of electrical generation services.

- **Why are so many local governments considering CCA?** CCAs provide consumer choice where none currently exists and have also resulted in lower electrical generation rates.[2] In addition,

[2] http://www.mcecleanenergy.org/residential-rates/

CCAs provide communities with local control over their energy supply, allowing them to increase the amount of electricity procured from renewable sources, such as solar, wind, and geothermal. CCAs can also develop innovative energy programs tailored specifically to their communities and support the development of local renewable energy projects. Finally, CCAs introduce competition into the energy market, which helps drive costs down, stimulate new energy investments, and diversify power choices. Customers in a CCA jurisdiction can choose to stay with the CCA program or return to PG&E's generation service; customers always have the power to choose.

- **What are the economic advantages of CCA?** In addition to the potential for customer rate savings and the economic value of ratepayer revenues serving our community rather than a utility territory ten times our size, CCAs can aCCAlerate the development of local renewable energy projects and facilitate other energy innovations such as energy efficiency retrofits, home area networks, battery storage and EV charging stations to name a few. This translates into the potential for new local services and consumer benefits as well as significant regional and local job creation. It should be noted that renewable energy facilities provide many more jobs per unit of investment than traditional natural gas and coal plants.[3]

- **What are the environmental advantages of CCA?** CCAs can choose to purchase from and develop electricity sources that are more heavily weighted towards renewable energy and carbon free power resources. The production and burning of traditional energy sources, such as coal and natural gas, generates large amounts of GHG emissions into the atmosphere. These GHG emissions are a leading cause of pollution and climate change.

- **How does this relate to my city's Climate Action Plan?** Many cities and counties now have "Climate Action Plans" that outline various measures that the city or county can take to reduce its GHG emissions and conserve natural resources. In Santa Clara County, electricity consumption is a main source of GHG emissions. Joining a CCA is one way jurisdictions in the county can reduce their GHG emissions from electricity and meet their local climate goals.

- **Has this been done in other areas and what are the results?** There are two CCA programs up and running in California: Marin Clean Energy (MCE) in Marin County and Sonoma Clean Power (SCP) in Sonoma County. Both MCE and SCP offer their customers 10-30 percent more renewable energy than PG&E at prices that are competitive and currently lower than PG&E's rates. MCE and SCP are now actively procuring and co-developing in-State and local renewable resources and offering specialized energy programs designed for their local service areas. A third CCA in the City of Lancaster will begin serving customers in May, 2015 and there are many local governments in California currently investigating CCA's potential for their communities.

- **If a CCA is formed in Silicon Valley/Santa Clara County, what is PG&E's role?** If a CCA forms in Santa Clara County, the CCA would be responsible for buying and/or developing all the electricity required to meet the demands of its customers. Customers who choose to opt-out of the CCA would continue to have PG&E buy their electricity. All customers, whether they are a part of the CCA not, continue to pay PG&E for transmission and distribution services and receive

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http://sonomacleanpower.org/for-my-home/rates/

[3] Pollin, Robert.2012, *Economic prospects-getting real on jobs and the environment: pipelines, fracking or clean energy?*, New Labor Forum 21(3):84-87.

a single, consolidated bill from PG&E. The only difference between a CCA and PG&E customer's bill is the source of electricity and line-item charge for energy generation.

- **If the power goes out, will PG&E still fix a CCA customer's outage problem?** Yes, PG&E continues to provide the same delivery, line maintenance, and customer services regardless of whether that home or business is part of the CCA program.

- **If I join a CCA, will my electricity rates go up?** A technical study will examine the impacts of a CCA on rates, but so far, CCA electrical rates have generally been 5 - 8 percent lower than PG&E's rates. This is dependent on the customer class and the particular CCA option each customer chooses. Current CCAs offer a "default" option that is both cleaner and cheaper than PG&E, as well as a 100% renewable energy option that is slightly more expensive than PG&E's default product. In addition, CCAs have the added advantage of price stability. While PG&E rates change several times a year, CCA rates generally adjust once per year, offering a measure of rate stability for CCA customers. While there is no guarantee that CCA generation rates will always be lower than PG&E's generation rates, CCAs do have the advantage of being small, non-profit agencies that pay no shareholder dividends, high corporate salaries, or income taxes like investor-owned utilities do.

- **How does a CCA procure electricity?** A CCA must submit a plan to the California Public Utilities Commission (CPUC) that specifies how it will purchase 115 percent of the estimated electricity demand for its area for a period of one year. Once the plan is approved, CCAs negotiate the purchase of electricity for its service area on the open energy market by entering in power purchase agreements (PPAs) with energy providers. These PPAs can be long or short term, depending on the needs of the CCA and type of energy being provided. A CCA can also sponsor a bidding process whereby project developers can bid to build new electricity sources solely for CCA customers. Through a utility service agreement, the power a CCA procures is transmitted over PG&E's power lines.

- **Do the electrons purchased or generated by the CCA actually go to my house?** No, when we say that the CCA supplies power to customers, we mean that the CCA puts the same amount of electricity onto the grid that its customers use. When the individual electrons from all power resources go onto the grid no one can determine which electrons go where. Think of it as depositing $100 in one ATM and taking out $100 in another. It's not the same $100 bill, but it's still your money. One can think of electricity in the same way. If you consume 500 kilowatt-hours in a month, the CCA must supply 500 kWH to the grid on your behalf. The advantage of a CCA is that what's supplied to the grid on your behalf can be both cleaner and less expensive than what PG&E is putting on the grid.

- **How is a CCA program set up?** Local governments must pass an ordinance to join a CCA program, and the CCA agency must draft an Implementation Plan that is approved by the CPUC. This is typically done after an initial technical study to determine the amount of electricity that will be required and to examine a CCA's ability to be cost competitive with PG&E. The Implementation Plan outlines how the CCA will function, how it will set rates, how it will procure electricity, and how it will carry out all other functions required under CPUC regulations.

- **I have heard that CCAs are "opt-out" programs. What does that mean?** When a county or city decides to create or join a CCA, all customers within that jurisdiction are automatically enrolled in the CCA; the CCA becomes the default provider of electrical supply. However, any customer can choose to opt-out and return to the incumbent utility (PG&E) for *generation* service at any time (remember: gas service, electric power delivery and customer billing is always provided by PG&E). State law requires that customers receive several notifications to opt-out just before and just after a CCA program launches. At any time after that initial launch period, a CCA customer can return to the incumbent utility's service for a small administration fee.

- **What is the governance structure of a CCA?** There is no law regulating how the how the governing body a CCA should be structured, so each CCA is a little different. Most CCAs are governed under a Joint Powers Agreement by a Board of Directors. The Board of Directors is usually comprised of a representative from each member city (and the county) within the CCA jurisdiction. The Board sets the CCA's policies and electricity rates. A CCA may also have an advisory committee made up of representatives from other stakeholder groups, such as local businesses and community organizations. CCAs also employ a small staff to run the day-to-day operations of the program and interface with CCA customers. As a public agency, the CCA process is designed to be very transparent with all meetings and information open to the public.

- **If I installed solar panels on my home or business, would I need a Power Purchase Agreement to sell our excess energy to a CCA?** No. This is called net metering, and the CCA would be able to offer property owners fair market rates for their excess energy production without a Purchase Power Agreement, even if that solar installation took place before the CCA launched. CCAs have been able to offer better net metering rates for customers who generate surplus electricity, and those customers would automatically be enrolled into a CCA's net metering program, unless they choose to opt-out and remain with PG&E. Larger solar projects that are "in front of the meter" can also be facilitated under a CCA's feed-in-tariff program which uses a standard power contract with set prices to buy all the power generated from that facility on behalf of CCA customers.

- **Are there other websites/resources I can check out?** Yes.

  For information about Marin's CCA program, go to www.mcecleanenergy.com

  For information Sonoma's CCA program, go to www.sonomacleanpower.org.

  For general information about CCA, go to www.leanenergyus.org.

- **I want to learn more about the Silicon Valley Community Choice Energy Partnership. Who can I contact?** For more information and contact information, please visit…..

APPENDIX C

MCE/SCP RATE COMPARISONS AND POWER CONTENT LABELS

2015 Residential Cost Comparison

Sonoma Clean Power

Example Residential Electric Charges Based on a home using 500 kWh per month on the RES-1 (E-1) rate	PG&E* 28%[1] Renewable Energy	CleanStart 33% Renewable Energy	EverGreen 100% Renewable Energy
Electric Generation (all customers)	$48.73	$35.50	$53.00
PG&E Electric Delivery* (all customers)	$58.85	$58.85	$58.85
Additional PG&E Fees (SCP customers only)	$0.00	$6.17	$6.17
	Average Total Cost $107.57	Average Total Cost $100.52	Average Total Cost $118.02

*PG&E fees are calculated by Sonoma Clean Power using rate data provided by PG&E effective on January 1, 2015.

2015 MCE Residential Cost Comparison

MCE Clean Energy

508 kWh E-1/Res-1	PG&E 22%	MCE Light Green 50%	MCE Deep Green 100%	MCE Local Solar 100%
Delivery	$44.37	$44.37	$44.37	$44.37
Generation	$49.50	$40.13	$45.21	$72.14
PG&E Fees	-	$6.27	$6.27	$6.27
Total Cost	**$93.87**	**$90.77**	**$95.85**	**$122.78**

- Delivery rates stay the same
- Generation rates vary by service option
- PG&E adds exit fees on CCA customer bills
- Even with exit fees, total cost for Light Green is less than PG&E

20

Electric Power Generation Mix*

Specific Purchases	PG&E	Sonoma Clean Power CleanStart	Sonoma Clean Power EverGreen
	Percent of Total Retail Sales (kWh)		
Renewable	27%	36%	100%
• Biomass & Biowaste	5%	3%	0%
• Geothermal	5%	12%	100%
• Eligible hydroelectric	1%	0%	0%
• Solar electric	9%	0%	0%
• Wind	7%	21%	0%
Coal	0%	0%	0%
Large hydroelectric	8%	44%	0%
Natural Gas	24%	0%	0%
Nuclear	21%	0%	0%
Other	0%	0%	0%
Unspecified Sources of Power	21%	20%	0%
TOTAL	**100%**	**100%**	**100%**

*The generation data represents 2014 and is provided in the "Annual Report to the California Energy Commission: Power Source Disclosure Program," excluding voluntary unbundled renewable energy credits. PG&E data is subject to an independent audit and verification that will not be completed until October 1, 2015.

APPENDIX D

MCE 2015/2016 OPERATING BUDGET

MARIN CLEAN ENERGY

OPERATING FUND
Proposed Budget
Fiscal Year 2015/16

	2014/15 Proposed Amended Budget	2015/16 Proposed Budget	Increase (Decrease)
REVENUE AND OTHER SOURCES:			
Revenue - Electricity (net of allowance)	$ 99,126,394	$ 145,933,097	$ 46,806,703
Revenue - Consideration from lease termination	400,000	-	(400,000)
Total sources	99,526,394	145,933,097	46,406,703
EXPENDITURES AND OTHER USES:			
CURRENT EXPENDITURES			
Cost of energy	87,900,551	129,522,715	41,622,164
Personnel	2,140,000	2,964,000	824,000
Technical consultants	545,000	629,000	84,000
Legal counsel	405,000	360,000	(45,000)
Communications consultants and related expenses	750,000	751,000	1,000
Data manager	2,550,000	2,862,000	312,000
Service fees - PG&E	705,000	921,000	216,000
Other services	354,000	418,000	64,000
General and administration	370,000	329,000	(41,000)
Occupancy	-	260,000	260,000
Integrated demand side pilot programs	-	50,000	50,000
Marin County green business program	15,000	10,000	(5,000)
Low income solar programs	25,000	35,000	10,000
Total current expenditures	95,759,551	139,111,715	43,352,164
CAPITAL OUTLAY	420,000	150,000	(270,000)
DEBT SERVICE	1,195,000	1,020,000	(175,000)
INTERFUND TRANSFER TO:			
Renewable Energy Reserve Fund	-	1,000,000	1,000,000
Local Renewable Energy Development Fund	109,994	151,383	41,389
Total interfund transfers	109,994	1,151,383	1,041,389
Total expenditures	97,484,545	141,433,098	43,948,553
Net increase (decrease) in available fund balance	$ 2,041,849	$ 4,500,000	$ 2,458,151

NOTES/COMMENTS

Electricity Revenue - projected revenue includes expanded territories and rate increases.
Cost of energy - projected cost of energy includes expanded territories.
Personnel - increase due to planned staff hires for new territories, transitioning work performed by external communications consultants to staff, and cost of living adjustments and raises.
Technical consultants - costs increase with expanded territory.
Legal - drop from prior year, when unexpected costs related to AB 2145 occurred.
Communications - essentially holding flat, with transition to replace external consultants with staff.
Data Manager - Noble Solutions charges per meter, which increased with territory expansion.
Service Fees PG&E - charged by the account which increased with territory expansion.
Other Services - planned increase for inflation, costs related to setting up thenew building.
G&A - this category no longer includes office lease, so the budget is reduced from last year. Costs associated with the new building and additional staff will offset some of this savings.
Occupancy - this new catefory includes office lease, utilities and maintenance in the new office building.
Capital Outlay - capital required for tenant improvements, employee workstations in new building.

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2016	2017	2018	2016 JAN	2016 FEB	2016 MAR	*Program Launch* 2016 APR	2016 MAY	2016 JUN
Energy Requirements (MWH)									
LOAD AT METER	2,643,746	3,394,705	3,409,143	-	-	-	296,190	285,213	284,494
LOSS ADJUSTED LOAD (LAL)	2,744,078	3,523,601	3,538,588	-	-	-	307,223	295,877	295,204
On Peak	1,732,169	2,219,956	2,229,398	-	-	-	198,334	187,465	184,448
Off Peak	1,011,909	1,303,645	1,309,190	-	-	-	108,890	108,413	110,755
BILATERAL CONTRACTS & MARKET PURCHASES									
On Peak - SP15 (EZGen)	1,795,835	2,282,573	2,292,282	-	-	-	198,238	187,567	184,455
Off Peak - SP15 (EZGen)	1,011,718	1,303,404	1,308,948	-	-	-	108,854	108,321	110,805
Market Purchases	108,739	136,355	136,935	-	-	-	12,132	15,445	12,003
Market Sales	172,215	198,731	199,576	-	-	-	12,002	15,456	12,061
RPS Category 1	567,084	840,189	843,763				63,009	63,009	63,009
RPS Category 2	305,353	280,063	281,254				33,928	33,928	33,928
RPS Category 3	-	-	-				-	-	-
GHG Free	-	-	-				-	-	-
Energy Prices ($/MWH)									
BASE POWER PRICE									
On Peak - SP15 (EZGen)	$40.52	$42.94	$45.42	$39.80	$40.14	$38.96	$37.38	$36.91	$36.88
Off Peak - SP15 (EZGen)	$32.52	$34.43	$36.35	$33.06	$33.16	$32.00	$30.53	$28.84	$26.49
RPS CATEGORY 1 ADDER	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00
RPS CATEGORY 2 ADDER	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00
RPS CATEGORY 3 ADDER									
CARBON FREE ADDER	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50
Energy Costs									
ENERGY	$118,130,103	$158,373,736	$168,235,993	$0	$0	$0	$11,660,087	$11,202,360	$10,611,049
RPS & GHG FREE ADDERS	$16,009,204	$22,685,116	$22,781,601	$0	$0	$0	$1,778,800	$1,778,800	$1,778,800
CAISO CHARGES & CONGESTION COSTS	$14,735,253	$19,755,143	$20,985,336	$0	$0	$0	$1,454,450	$1,397,354	$1,323,596
NET ENERGY METERING PROGRAM	$679,034	$767,503	$794,943	$0	$0	$0	$45,060	$114,761	$151,190
TOTAL	$149,553,593	$201,581,499	$212,797,874	$0	$0	$0	$14,938,398	$14,493,276	$13,864,634
RA Obligations & Allocations (MW-Mo)									
PEAK MW (LAL)	5,583	6,949	6,977	-	-	-	655	665	547
PEAK MW (CEC ADJ. FOR COINCIDENCE & DER)	4,937	6,010	6,034	-	-	-	622	640	488
ZONAL TOTAL (CEC ADJ. PEAK X 115%)	**5,677**	**6,912**	**6,939**	-	-	-	**715**	**735**	**562**
DR Allocation - System	-	-	-	-	-	-	-	-	-
DR Allocation - San Diego IV	97	105	105	-	-	-	6	11	12
RMR Allocation	-	-	-	-	-	-	-	-	-
CAM Allocation	75	269	1,100	-	-	-	10	8	9
San Diego IV	75	269	1,100	-	-	-	10	8	9
Flex Cap Category 1	-	171	1,002	-	-	-	-	-	-
Flex Cap Category 2	75	98	98	-	-	-	10	8	9
Flex Cap Category 3	-	-	-	-	-	-	-	-	-
ZONAL OBLIGATION (TOTAL-RMR-CAM-DR)	**5,505**	**6,538**	**5,734**	-	-	-	**699**	**716**	**541**
System	2,256	2,869	3,003	-	-	-	284	292	223
LCR - San Diego IV	3,249	3,670	2,731	-	-	-	415	424	318
Flexible	1,268	1,559	735	-	-	-	196	147	92
Category 1	1,008	1,145	319	-	-	-	131	135	87
Category 2	193	323	324	-	-	-	55	4	(1)
Category 3	67	91	92	-	-	-	10	8	5
Generic	4,237	4,979	4,999	-	-	-	503	570	450

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2016 JUL	2016 AUG	2016 SEP	2016 OCT	2016 NOV	2016 DEC	2017 JAN	2017 FEB	2017 MAR	2017 APR
Energy Requirements (MWH)										
LOAD AT METER	325,187	291,616	344,171	280,257	262,878	273,741	291,904	268,750	265,019	264,743
LOSS ADJUSTED LOAD (LAL)	337,671	302,906	357,673	290,822	272,579	284,123	303,159	278,951	274,940	274,604
On Peak	213,859	191,765	226,737	189,723	163,112	176,726	189,198	177,206	170,826	177,276
Off Peak	123,813	111,141	130,936	101,098	109,467	107,397	113,961	101,745	104,114	97,328
BILATERAL CONTRACTS & MARKET PURCHASES										
On Peak - SP15 (EZGen)	235,327	211,004	249,523	189,741	163,188	176,792	189,204	177,114	170,851	177,191
Off Peak - SP15 (EZGen)	123,823	111,162	130,846	101,013	109,526	107,367	113,924	101,648	104,189	97,297
Market Purchases	9,746	8,738	14,068	13,539	11,982	11,086	10,673	10,152	9,990	10,844
Market Sales	31,224	27,997	36,764	13,472	12,118	11,123	10,642	9,964	10,090	10,727
RPS Category 1	63,009	63,009	63,009	63,009	63,009	63,009	70,016	70,016	70,016	70,016
RPS Category 2	33,928	33,928	33,928	33,928	33,928	33,928	23,339	23,339	23,339	23,339
RPS Category 3	-	-	-	-	-	-	-	-	-	-
GHG Free	-	-	-	-	-	-	-	-	-	-
Energy Prices ($/MWH)										
BASE POWER PRICE										
On Peak - SP15 (EZGen)	$42.46	$43.58	$43.42	$43.08	$42.02	$41.61	$42.13	$42.35	$41.06	$39.42
Off Peak - SP15 (EZGen)	$31.80	$33.23	$33.73	$35.83	$35.45	$36.12	$35.86	$36.05	$35.37	$31.35
RPS CATEGORY 1 ADDER	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00
RPS CATEGORY 2 ADDER	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00
RPS CATEGORY 3 ADDER										
CARBON FREE ADDER	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50
Energy Costs										
ENERGY	$15,677,445	$14,506,594	$17,489,240	$12,998,158	$11,784,211	$12,200,959	$12,988,352	$12,052,291	$11,559,218	$10,903,213
RPS & GHG FREE ADDERS	$1,778,800	$1,778,800	$1,778,800	$1,778,800	$1,778,800	$1,778,800	$1,890,426	$1,890,426	$1,890,426	$1,890,426
CAISO CHARGES & CONGESTION COSTS	$1,955,565	$1,809,516	$2,181,564	$1,621,358	$1,469,933	$1,521,917	$1,620,135	$1,503,372	$1,441,868	$1,360,039
NET ENERGY METERING PROGRAM	$105,937	$124,702	$61,292	$57,531	$13,760	$4,800	$6,553	$9,008	$30,926	$48,326
TOTAL	$19,517,748	$18,219,612	$21,510,897	$16,455,847	$15,046,705	$15,506,477	$16,505,466	$15,455,097	$14,922,438	$14,202,005
RA Obligations & Allocations (MW-Mo)										
PEAK MW (LAL)	667	600	808	594	544	504	530	530	467	585
PEAK MW (CEC ADJ. FOR COINCIDENCE & DER)	624	557	719	530	421	336	409	418	399	556
ZONAL TOTAL (CEC ADJ. PEAK X 115%)	**718**	**640**	**826**	**610**	**484**	**386**	**470**	**480**	**459**	**639**
DR Allocation - System	-	-	-	-	-	-	-	-	-	-
DR Allocation - San Diego IV	16	14	19	12	5	3	4	3	3	5
RMR Allocation	-	-	-	-	-	-	-	-	-	-
CAM Allocation	8	8	8	7	9	8	8	9	8	9
San Diego IV	8	8	8	7	9	8	8	9	8	9
Flex Cap Category 1	-	-	-	-	-	-	-	-	-	-
Flex Cap Category 2	8	8	8	7	9	8	8	9	8	9
Flex Cap Category 3	-	-	-	-	-	-	-	-	-	-
ZONAL OBLIGATION (TOTAL-RMR-CAM-DR)	**693**	**618**	**800**	**591**	**471**	**375**	**458**	**468**	**448**	**625**
System	285	254	328	242	192	154	195	199	191	265
LCR - San Diego IV	408	364	471	348	278	222	263	269	257	360
Flexible	114	100	165	159	161	135	153	155	147	186
Category 1	107	94	151	106	108	91	103	104	98	123
Category 2	1	1	5	45	44	37	42	43	41	52
Category 3	6	5	9	8	8	7	8	8	8	10
Generic	579	519	635	431	310	240	305	313	301	439

COMMUNITY CHOICE PARTNERS
SECURING YOUR COMMUNITY'S ENERGY FUTURE

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2017 MAY	2017 JUN	2017 JUL	2017 AUG	2017 SEP	2017 OCT	2017 NOV	2017 DEC	2018 JAN	2018 FEB
Energy Requirements (MWH)										
LOAD AT METER	267,405	276,140	318,538	287,129	340,288	278,439	261,989	274,359	293,146	269,893
LOSS ADJUSTED LOAD (LAL)	277,404	286,535	330,767	298,245	353,638	288,936	271,658	284,764	304,448	280,137
On Peak	175,760	179,032	209,486	188,815	224,179	188,493	162,561	177,124	190,002	177,960
Off Peak	101,644	107,503	121,281	109,431	129,459	100,443	109,097	107,639	114,446	102,177
BILATERAL CONTRACTS & MARKET PURCHASES										
On Peak - SP15 (EZGen)	175,856	179,039	230,515	207,757	246,708	188,511	162,637	177,191	190,009	177,867
Off Peak - SP15 (EZGen)	101,558	107,552	121,291	109,451	129,370	100,358	109,156	107,610	114,409	102,080
Market Purchases	14,480	11,651	9,547	8,603	13,909	13,452	11,942	11,111	10,719	10,196
Market Sales	14,491	11,706	30,586	27,567	36,349	13,384	12,077	11,148	10,688	10,006
RPS Category 1	70,016	70,016	70,016	70,016	70,016	70,016	70,016	70,016	70,314	70,314
RPS Category 2	23,339	23,339	23,339	23,339	23,339	23,339	23,339	23,339	23,438	23,438
RPS Category 3	-	-	-	-	-	-	-	-	-	-
GHG Free	-	-	-	-	-	-	-	-	-	-
Energy Prices ($/MWH)										
BASE POWER PRICE										
On Peak - SP15 (EZGen)	$39.01	$39.03	$45.63	$46.88	$46.63	$44.33	$43.59	$45.20	$46.27	$45.98
Off Peak - SP15 (EZGen)	$29.64	$27.18	$34.62	$36.15	$36.73	$37.01	$36.47	$36.74	$38.44	$37.98
RPS CATEGORY 1 ADDER	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00
RPS CATEGORY 2 ADDER	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00
RPS CATEGORY 3 ADDER										
CARBON FREE ADDER	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50
Energy Costs										
ENERGY	$11,004,803	$10,799,767	$16,564,000	$15,413,516	$18,645,239	$13,304,665	$12,146,686	$12,991,986	$14,210,277	$13,011,633
RPS & GHG FREE ADDERS	$1,890,426	$1,890,426	$1,890,426	$1,890,426	$1,890,426	$1,890,426	$1,890,426	$1,890,426	$1,898,467	$1,898,467
CAISO CHARGES & CONGESTION COSTS	$1,372,711	$1,347,136	$2,066,152	$1,922,643	$2,325,760	$1,659,591	$1,515,147	$1,620,588	$1,772,554	$1,623,039
NET ENERGY METERING PROGRAM	$124,338	$160,574	$114,035	$131,603	$63,416	$59,523	$14,235	$4,966	$6,786	$9,329
TOTAL	$14,392,278	$14,197,904	$20,634,614	$19,358,188	$22,924,841	$16,914,205	$15,566,495	$16,507,966	$17,888,085	$16,542,468
RA Obligations & Allocations (MW-Mo)										
PEAK MW (LAL)	624	531	654	591	799	591	543	505	532	532
PEAK MW (CEC ADJ. FOR COINCIDENCE & DER)	600	474	612	548	711	527	420	337	410	419
ZONAL TOTAL (CEC ADJ. PEAK X 115%)	**690**	**546**	**703**	**631**	**818**	**606**	**483**	**387**	**472**	**482**
DR Allocation - System	-	-	-	-	-	-	-	-	-	-
DR Allocation - San Diego IV	10	11	16	14	18	12	5	3	4	3
RMR Allocation	-	-	-	-	-	-	-	-	-	-
CAM Allocation	8	8	8	7	8	7	99	89	94	98
San Diego IV	8	8	8	7	8	7	99	89	94	98
Flex Cap Category 1	-	-	-	-	-	-	90	81	85	90
Flex Cap Category 2	8	8	8	7	8	7	9	8	8	9
Flex Cap Category 3	-	-	-	-	-	-	-	-	-	-
ZONAL OBLIGATION (TOTAL-RMR-CAM-DR)	**672**	**526**	**680**	**609**	**791**	**587**	**380**	**295**	**375**	**380**
System	286	226	292	262	339	252	200	161	204	209
LCR - San Diego IV	386	299	388	348	452	335	179	134	170	172
Flexible	144	92	114	98	171	165	76	59	68	66
Category 1	132	88	107	92	156	109	21	13	18	15
Category 2	4	(0)	2	1	6	47	46	39	43	43
Category 3	8	5	6	5	9	9	9	7	8	8
Generic	528	434	565	511	620	422	304	236	306	315

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2018 MAR	2018 APR	2018 MAY	2018 JUN	2018 JUL	2018 AUG	2018 SEP	2018 OCT	2018 NOV	2018 DEC
Energy Requirements (MWH)										
LOAD AT METER	266,147	265,869	268,543	277,315	319,893	288,351	341,735	279,624	263,104	275,526
LOSS ADJUSTED LOAD (LAL)	276,109	275,772	278,584	287,754	332,174	299,514	355,142	290,165	272,813	285,975
On Peak	171,552	178,030	176,508	179,794	210,377	189,618	225,133	189,295	163,252	177,878
Off Peak	104,557	97,742	102,076	107,960	121,797	109,896	130,010	100,870	109,561	108,097
BILATERAL CONTRACTS & MARKET PURCHASES										
On Peak - SP15 (EZGen)	171,577	177,945	176,604	179,801	231,495	208,641	247,757	189,313	163,328	177,945
Off Peak - SP15 (EZGen)	104,632	97,711	101,990	108,009	121,807	109,917	129,920	100,785	109,620	108,067
Market Purchases	10,032	10,890	14,542	11,700	9,587	8,640	13,968	13,509	11,993	11,158
Market Sales	10,133	10,773	14,552	11,756	30,716	27,684	36,504	13,441	12,128	11,195
RPS Category 1	70,314	70,314	70,314	70,314	70,314	70,314	70,314	70,314	70,314	70,314
RPS Category 2	23,438	23,438	23,438	23,438	23,438	23,438	23,438	23,438	23,438	23,438
RPS Category 3	-	-	-	-	-	-	-	-	-	-
GHG Free	-	-	-	-	-	-	-	-	-	-
Energy Prices ($/MWH)										
BASE POWER PRICE										
On Peak - SP15 (EZGen)	$43.17	$41.50	$43.90	$46.93	$50.84	$49.46	$48.23	$42.75	$42.77	$43.29
Off Peak - SP15 (EZGen)	$35.45	$33.89	$34.30	$33.70	$38.08	$37.71	$37.46	$35.56	$36.09	$37.57
RPS CATEGORY 1 ADDER	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00
RPS CATEGORY 2 ADDER	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00
RPS CATEGORY 3 ADDER										
CARBON FREE ADDER	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50
Energy Costs										
ENERGY	$12,008,109	$11,621,196	$12,544,137	$13,160,133	$18,464,771	$16,277,478	$19,287,345	$12,870,129	$12,005,430	$12,775,355
RPS & GHG FREE ADDERS	$1,898,467	$1,898,467	$1,898,467	$1,898,467	$1,898,467	$1,898,467	$1,898,467	$1,898,467	$1,898,467	$1,898,467
CAISO CHARGES & CONGESTION COSTS	$1,497,861	$1,449,599	$1,564,724	$1,641,562	$2,303,249	$2,030,412	$2,405,855	$1,605,388	$1,497,527	$1,593,566
NET ENERGY METERING PROGRAM	$32,029	$50,050	$128,785	$166,318	$118,114	$136,310	$65,685	$61,652	$14,742	$5,143
TOTAL	$15,436,465	$15,019,312	$16,136,113	$16,866,479	$22,784,601	$20,342,667	$23,657,351	$16,435,636	$15,416,166	$16,272,530
RA Obligations & Allocations (MW-Mo)										
PEAK MW (LAL)	469	588	626	533	657	593	802	593	545	507
PEAK MW (CEC ADJ. FOR COINCIDENCE & DER)	401	558	602	476	614	550	714	529	422	338
ZONAL TOTAL (CEC ADJ. PEAK X 115%)	**461**	**642**	**693**	**548**	**706**	**633**	**821**	**609**	**485**	**389**
DR Allocation - System	-	-	-	-	-	-	-	-	-	-
DR Allocation - San Diego IV	3	5	10	11	16	14	18	12	5	3
RMR Allocation	-	-	-	-	-	-	-	-	-	-
CAM Allocation	89	99	86	94	92	83	93	83	99	89
San Diego IV	89	99	86	94	92	83	93	83	99	89
Flex Cap Category 1	81	90	79	86	84	76	85	75	90	81
Flex Cap Category 2	8	9	8	8	8	7	8	7	9	8
Flex Cap Category 3	-	-	-	-	-	-	-	-	-	-
ZONAL OBLIGATION (TOTAL-RMR-CAM-DR)	**369**	**537**	**596**	**442**	**598**	**536**	**709**	**514**	**382**	**296**
System	199	278	300	237	306	274	355	263	210	168
LCR - San Diego IV	169	259	296	205	293	262	354	251	172	128
Flexible	66	96	66	7	31	23	87	90	77	59
Category 1	17	34	54	2	23	16	72	35	21	13
Category 2	41	53	4	(0)	2	1	6	47	46	39
Category 3	8	10	8	5	6	5	9	9	9	7
Generic	302	441	530	435	567	513	623	424	305	237

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2016	2017	2018	2016 JAN	2016 FEB	2016 MAR	*Program Launch* 2016 APR	2016 MAY	2016 JUN
RA Prices ($/kW-Mo)									
SYSTEM	$3.46	$3.00	$3.09	$0.77	$0.56	$0.54	$0.59	$0.84	$1.63
SAN DIEGO IV	$5.17	$4.54	$4.78	$0.59	$0.38	$0.42	$0.44	$0.78	$1.72
FLEX ADDER	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RA Cost									
SYSTEM	$7,797,648	$8,609,251	$9,282,628	$0	$0	$0	$166,315	$244,906	$362,831
SAN DIEGO IV	$16,794,646	$16,676,960	$13,041,814	$0	$0	$0	$180,939	$331,968	$547,124
FLEX ADDER	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CAPACITY COST	$24,592,294	$25,286,210	$22,324,442	$0	$0	$0	$347,254	$576,874	$909,954
Customer Base & Retail Rates									
CUSTOMER ACCOUNTS									
Agricultural	154	137	137	-	-	-	154	146	141
Commercial/Industrial - Large	234	209	209	-	-	-	234	224	216
Commercial/Industrial - Medium	3,918	3,489	3,489	-	-	-	3,918	3,735	3,608
Commercial/Industrial - Small	43,800	39,006	39,006	-	-	-	43,800	41,756	40,334
Outdoor Lighting - Residential	-	-	-	-	-	-	-	-	-
Outdoor Lighting - Small Commercial	72	64	64	-	-	-	72	69	66
Residential	209,623	186,682	186,682	-	-	-	209,623	199,844	193,035
Total	257,801	229,587	229,587	-	-	-	257,801	245,774	237,400
KWH BY CLASS	2,643,745,939	3,394,705,030	3,409,143,467	-	-	-	296,189,762	285,212,580	284,494,399
Agricultural	32,716,742	40,863,926	41,037,729	-	-	-	3,819,296	3,514,485	3,602,684
Commercial/Industrial - Large	713,936,062	888,821,637	892,601,993	-	-	-	75,763,706	78,451,373	75,005,605
Commercial/Industrial - Medium	654,714,656	841,118,602	844,696,067	-	-	-	77,523,000	71,547,576	73,464,501
Commercial/Industrial - Small	537,984,602	688,830,192	691,759,941	-	-	-	60,949,501	58,517,473	59,016,370
Outdoor Lighting - Residential	-	-	-	-	-	-	-	-	-
Outdoor Lighting - Small Commercial	19,216,627	24,623,950	24,728,681	-	-	-	2,268,043	2,162,866	2,133,135
Residential	685,177,250	910,446,723	914,319,056	-	-	-	75,866,217	71,018,807	71,272,103
Total	2,643,745,939	3,394,705,030	3,409,143,467	-	-	-	296,189,762	285,212,580	284,494,399
SDG&E CLASS AVERAGE WTD. AV. RATE									
Agricultural	$0.08	$0.09	$0.09	$0.06	$0.06	$0.06	$0.06	$0.11	$0.11
Commercial/Industrial - Large	$0.10	$0.10	$0.11	$0.07	$0.07	$0.07	$0.07	$0.13	$0.13
Commercial/Industrial - Medium	$0.10	$0.10	$0.11	$0.07	$0.07	$0.07	$0.07	$0.13	$0.13
Commercial/Industrial - Small	$0.10	$0.10	$0.10	$0.07	$0.07	$0.07	$0.07	$0.13	$0.13
Outdoor Lighting - Residential	$0.06	$0.07	$0.07	$0.04	$0.04	$0.04	$0.04	$0.08	$0.08
Outdoor Lighting - Small Commercial	$0.06	$0.07	$0.07	$0.04	$0.04	$0.04	$0.04	$0.08	$0.08
Residential	$0.10	$0.11	$0.11	$0.07	$0.07	$0.07	$0.07	$0.13	$0.13
Total	$0.11	$0.10	$0.11						
GROSS REVENUE BY CLASS									
Agricultural	$3,021,712	$3,571,365	$3,715,262	$0	$0	$0	$214,545	$381,981	$391,568
Commercial/Industrial - Large	$81,242,673	$95,695,500	$99,551,237	$0	$0	$0	$5,197,628	$10,413,358	$9,955,979
Commercial/Industrial - Medium	$73,276,528	$88,348,755	$91,908,479	$0	$0	$0	$5,318,321	$9,496,972	$9,751,418
Commercial/Industrial - Small	$57,842,823	$69,538,281	$72,340,098	$0	$0	$0	$3,999,316	$7,429,292	$7,492,631
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$1,350,663	$1,627,260	$1,692,825	$0	$0	$0	$98,376	$181,515	$179,020
Residential	$77,742,236	$95,924,188	$99,789,139	$0	$0	$0	$5,276,097	$9,556,173	$9,590,256
Total	$294,476,635	$354,705,350	$368,997,040	$0	$0	$0	$20,104,283	$37,459,291	$37,360,871

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION

SHORT TERM COST OF SERVICE MODEL	2016 JUL	2016 AUG	2016 SEP	2016 OCT	2016 NOV	2016 DEC	2017 JAN	2017 FEB	2017 MAR	2017 APR
RA Prices ($/kW-Mo)										
SYSTEM	$7.65	$9.69	$4.85	$1.42	$1.24	$1.30	$0.79	$0.57	$0.55	$0.60
SAN DIEGO IV	$12.76	$16.80	$7.44	$1.19	$0.92	$1.03	$0.61	$0.40	$0.44	$0.45
FLEX ADDER	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RA Cost										
SYSTEM	$2,182,688	$2,465,350	$1,591,556	$345,011	$239,021	$199,971	$154,152	$114,012	$105,021	$160,025
SAN DIEGO IV	$5,210,202	$6,118,913	$3,505,463	$415,418	$257,203	$227,417	$159,865	$106,536	$112,249	$161,582
FLEX ADDER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CAPACITY COST	$7,392,889	$8,584,263	$5,097,019	$760,429	$496,223	$427,388	$314,017	$220,548	$217,270	$321,607
Customer Base & Retail Rates										
CUSTOMER ACCOUNTS										
Agricultural	140	139	139	138	138	137	137	137	137	137
Commercial/Industrial - Large	214	213	212	211	210	209	209	209	209	209
Commercial/Industrial - Medium	3,575	3,557	3,542	3,525	3,514	3,494	3,489	3,489	3,489	3,489
Commercial/Industrial - Small	39,967	39,761	39,596	39,405	39,282	39,061	39,006	39,006	39,006	39,006
Outdoor Lighting - Residential	-	-	-	-	-	-	-	-	-	-
Outdoor Lighting - Small Commercial	66	65	65	65	64	64	64	64	64	64
Residential	191,277	190,294	189,504	188,589	188,002	186,945	186,682	186,682	186,682	186,682
Total	235,239	234,029	233,058	231,933	231,210	229,910	229,587	229,587	229,587	229,587
KWH BY CLASS	325,186,767	291,616,056	344,170,618	280,256,627	262,877,764	273,741,366	291,904,393	268,750,107	265,019,446	264,742,575
Agricultural	4,008,410	3,622,027	4,030,008	3,766,641	3,433,683	2,919,509	3,059,837	2,954,991	3,075,667	3,413,792
Commercial/Industrial - Large	91,800,209	80,644,746	99,339,532	77,842,048	69,795,037	65,293,807	65,585,828	63,753,453	65,522,673	67,719,689
Commercial/Industrial - Medium	78,370,030	71,654,571	78,209,604	68,973,855	66,467,462	68,504,058	70,649,082	67,432,832	67,281,628	69,292,195
Commercial/Industrial - Small	65,649,508	59,820,927	67,425,713	57,052,029	53,719,388	55,833,693	57,626,798	54,644,897	53,880,431	54,478,344
Outdoor Lighting - Residential	-	-	-	-	-	-	-	-	-	-
Outdoor Lighting - Small Commercial	2,122,720	2,102,924	2,101,465	2,130,683	2,096,851	2,097,940	2,257,840	1,595,094	2,108,502	2,027,239
Residential	83,235,890	73,770,862	93,064,297	70,491,371	67,365,343	79,092,359	92,725,007	78,368,840	73,150,544	67,811,317
Total	325,186,767	291,616,056	344,170,618	280,256,627	262,877,764	273,741,366	291,904,393	268,750,107	265,019,446	264,742,575
SDG&E CLASS AVERAGE WTD. AV. RATE										
Agricultural	$0.11	$0.11	$0.11	$0.11	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Commercial/Industrial - Large	$0.13	$0.13	$0.13	$0.13	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Commercial/Industrial - Medium	$0.13	$0.13	$0.13	$0.13	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Commercial/Industrial - Small	$0.13	$0.13	$0.13	$0.13	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Outdoor Lighting - Residential	$0.08	$0.08	$0.08	$0.08	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Outdoor Lighting - Small Commercial	$0.08	$0.08	$0.08	$0.08	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Residential	$0.13	$0.13	$0.13	$0.13	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Total										
GROSS REVENUE BY CLASS										
Agricultural	$435,665	$393,670	$438,012	$409,388	$192,883	$164,000	$177,858	$171,763	$178,778	$198,432
Commercial/Industrial - Large	$12,185,235	$10,704,498	$13,185,978	$10,332,478	$4,788,159	$4,479,360	$4,655,796	$4,525,720	$4,651,313	$4,807,275
Commercial/Industrial - Medium	$10,402,561	$9,511,174	$10,381,266	$9,155,346	$4,559,876	$4,699,593	$5,015,226	$4,786,911	$4,776,178	$4,918,903
Commercial/Industrial - Small	$8,334,765	$7,594,777	$8,560,269	$7,243,241	$3,524,899	$3,663,633	$3,912,732	$3,710,267	$3,658,362	$3,698,959
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$178,146	$176,484	$176,362	$178,814	$90,950	$90,997	$101,337	$71,592	$94,635	$90,987
Residential	$11,200,083	$9,926,484	$12,522,577	$9,485,202	$4,684,906	$5,500,458	$6,672,694	$5,639,593	$5,264,073	$4,879,850
Total	$42,736,454	$38,307,088	$45,264,465	$36,804,468	$17,841,673	$18,598,042	$20,535,643	$18,905,846	$18,623,338	$18,594,406

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION

SHORT TERM COST OF SERVICE MODEL	2017 MAY	2017 JUN	2017 JUL	2017 AUG	2017 SEP	2017 OCT	2017 NOV	2017 DEC	2018 JAN	2018 FEB
RA Prices ($/kW-Mo)										
SYSTEM	$0.86	$1.67	$7.88	$9.98	$4.99	$1.47	$1.28	$1.34	$0.81	$0.59
SAN DIEGO IV	$0.81	$1.77	$13.15	$17.31	$7.66	$1.23	$0.95	$1.06	$0.63	$0.41
FLEX ADDER	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RA Cost										
SYSTEM	$247,176	$379,110	$2,301,573	$2,613,064	$1,693,947	$368,989	$256,431	$215,750	$166,209	$122,929
SAN DIEGO IV	$310,887	$530,188	$5,095,606	$6,015,274	$3,460,508	$412,150	$170,480	$141,633	$106,671	$70,103
FLEX ADDER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CAPACITY COST	$558,063	$909,298	$7,397,180	$8,628,338	$5,154,456	$781,139	$426,911	$357,383	$272,880	$193,032
Customer Base & Retail Rates										
CUSTOMER ACCOUNTS										
Agricultural	137	137	137	137	137	137	137	137	137	137
Commercial/Industrial - Large	209	209	209	209	209	209	209	209	209	209
Commercial/Industrial - Medium	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489
Commercial/Industrial - Small	39,006	39,006	39,006	39,006	39,006	39,006	39,006	39,006	39,006	39,006
Outdoor Lighting - Residential	-	-	-	-	-	-	-	-	-	-
Outdoor Lighting - Small Commercial	64	64	64	64	64	64	64	64	64	64
Residential	186,682	186,682	186,682	186,682	186,682	186,682	186,682	186,682	186,682	186,682
Total	229,587	229,587	229,587	229,587	229,587	229,587	229,587	229,587	229,587	229,587
KWH BY CLASS	267,405,241	276,140,424	318,537,745	287,129,380	340,287,996	278,439,439	261,989,480	274,358,804	293,145,927	269,893,161
Agricultural	3,295,057	3,496,894	3,926,451	3,566,300	3,984,545	3,742,218	3,422,080	2,926,094	3,072,852	2,967,560
Commercial/Industrial - Large	73,553,237	72,803,119	89,923,190	79,403,981	98,218,873	77,337,319	69,559,194	65,441,080	65,864,780	64,024,610
Commercial/Industrial - Medium	67,080,480	71,307,269	76,767,615	70,552,126	77,327,314	68,526,628	66,242,863	68,658,572	70,949,568	67,719,638
Commercial/Industrial - Small	54,863,916	57,283,397	64,307,187	58,900,549	66,665,077	56,682,103	53,537,866	55,959,629	57,871,897	54,877,314
Outdoor Lighting - Residential	-	-	-	-	-	-	-	-	-	-
Outdoor Lighting - Small Commercial	2,027,827	2,070,497	2,079,317	2,070,569	2,077,759	2,116,867	2,089,766	2,102,672	2,267,443	1,601,879
Residential	66,584,725	69,179,249	81,533,985	72,635,856	92,014,429	70,034,304	67,137,711	79,270,756	93,119,387	78,702,160
Total	267,405,241	276,140,424	318,537,745	287,129,380	340,287,996	278,439,439	261,989,480	274,358,804	293,145,927	269,893,161
SDG&E CLASS AVERAGE WTD. AV. RATE										
Agricultural	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.06	$0.06	$0.06	$0.06
Commercial/Industrial - Large	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.07	$0.07	$0.07	$0.07
Commercial/Industrial - Medium	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.07	$0.07	$0.07	$0.07
Commercial/Industrial - Small	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.07	$0.07	$0.07	$0.07
Outdoor Lighting - Residential	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.04	$0.04	$0.05	$0.05
Outdoor Lighting - Small Commercial	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.04	$0.04	$0.05	$0.05
Residential	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.07	$0.07	$0.07	$0.07
Total										
GROSS REVENUE BY CLASS										
Agricultural	$370,581	$393,281	$441,591	$401,087	$448,125	$420,872	$198,914	$170,084	$185,024	$178,684
Commercial/Industrial - Large	$10,102,573	$9,999,544	$12,350,995	$10,906,176	$13,490,411	$10,622,319	$4,937,857	$4,645,521	$4,843,386	$4,708,069
Commercial/Industrial - Medium	$9,213,537	$9,794,089	$10,544,070	$9,690,369	$10,620,945	$9,412,166	$4,702,438	$4,873,924	$5,217,298	$4,979,784
Commercial/Industrial - Small	$7,207,566	$7,525,418	$8,448,145	$7,737,866	$8,757,905	$7,446,425	$3,635,102	$3,799,535	$4,070,382	$3,859,760
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$176,098	$179,803	$180,569	$179,809	$180,434	$183,830	$93,794	$94,373	$105,420	$74,476
Residential	$9,270,971	$9,632,221	$11,352,441	$10,113,504	$12,811,693	$9,751,275	$4,831,376	$5,704,497	$6,941,548	$5,866,822
Total	$36,341,326	$37,524,356	$43,317,811	$39,028,811	$46,309,513	$37,836,887	$18,399,481	$19,287,933	$21,363,059	$19,667,595

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2018 MAR	2018 APR	2018 MAY	2018 JUN	2018 JUL	2018 AUG	2018 SEP	2018 OCT	2018 NOV	2018 DEC
RA Prices ($/kW-Mo)										
SYSTEM	$0.57	$0.62	$0.89	$1.72	$8.12	$10.28	$5.14	$1.51	$1.32	$1.38
SAN DIEGO IV	$0.45	$0.46	$0.83	$1.82	$13.54	$17.83	$7.89	$1.27	$0.98	$1.09
FLEX ADDER	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RA Cost										
SYSTEM	$113,236	$172,542	$266,509	$408,762	$2,481,592	$2,817,446	$1,826,440	$397,850	$276,488	$232,625
SAN DIEGO IV	$75,949	$120,054	$245,956	$374,374	$3,962,143	$4,666,988	$2,794,894	$317,145	$168,226	$139,310
FLEX ADDER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CAPACITY COST	$189,185	$292,596	$512,465	$783,136	$6,443,735	$7,484,434	$4,621,334	$714,995	$444,714	$371,935
Customer Base & Retail Rates										
CUSTOMER ACCOUNTS										
Agricultural	137	137	137	137	137	137	137	137	137	137
Commercial/Industrial - Large	209	209	209	209	209	209	209	209	209	209
Commercial/Industrial - Medium	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489	3,489
Commercial/Industrial - Small	39,006	39,006	39,006	39,006	39,006	39,006	39,006	39,006	39,006	39,006
Outdoor Lighting - Residential	-	-	-	-	-	-	-	-	-	-
Outdoor Lighting - Small Commercial	64	64	64	64	64	64	64	64	64	64
Residential	186,682	186,682	186,682	186,682	186,682	186,682	186,682	186,682	186,682	186,682
Total	229,587	229,587	229,587	229,587	229,587	229,587	229,587	229,587	229,587	229,587
KWH BY CLASS	266,146,632	265,868,585	268,542,575	277,314,911	319,892,557	288,350,605	341,735,317	279,623,704	263,103,779	275,525,713
Agricultural	3,088,748	3,428,311	3,309,072	3,511,767	3,943,151	3,581,468	4,001,492	3,758,134	3,436,635	2,938,539
Commercial/Industrial - Large	65,801,356	68,007,716	73,866,075	73,112,767	90,305,654	79,741,704	98,636,620	77,666,252	69,855,045	65,719,416
Commercial/Industrial - Medium	67,567,792	69,586,910	67,365,788	71,610,554	77,094,125	70,852,199	77,656,204	68,818,087	66,524,609	68,950,592
Commercial/Industrial - Small	54,109,596	54,710,053	55,097,264	57,527,036	64,580,700	59,151,066	66,948,618	56,923,184	53,765,575	56,197,638
Outdoor Lighting - Residential	-	-	-	-	-	-	-	-	-	-
Outdoor Lighting - Small Commercial	2,117,470	2,035,862	2,036,451	2,079,304	2,088,161	2,079,375	2,086,596	2,125,871	2,098,654	2,111,616
Residential	73,461,670	68,099,733	66,867,925	69,473,483	81,880,767	72,944,792	92,405,787	70,332,176	67,423,262	79,607,912
Total	266,146,632	265,868,585	268,542,575	277,314,911	319,892,557	288,350,605	341,735,317	279,623,704	263,103,779	275,525,713
SDG&E CLASS AVERAGE WTD. AV. RATE										
Agricultural	$0.06	$0.06	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.06	$0.06
Commercial/Industrial - Large	$0.07	$0.07	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.07	$0.07
Commercial/Industrial - Medium	$0.07	$0.07	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.07	$0.07
Commercial/Industrial - Small	$0.07	$0.07	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.07	$0.07
Outdoor Lighting - Residential	$0.05	$0.05	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.05	$0.05
Outdoor Lighting - Small Commercial	$0.05	$0.05	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.05	$0.05
Residential	$0.07	$0.07	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.07	$0.07
Total										
GROSS REVENUE BY CLASS										
Agricultural	$185,981	$206,427	$385,513	$409,127	$459,384	$417,247	$466,181	$437,829	$206,928	$176,937
Commercial/Industrial - Large	$4,838,722	$5,000,968	$10,509,624	$10,402,443	$12,848,637	$11,345,605	$14,033,963	$11,050,311	$5,136,812	$4,832,697
Commercial/Industrial - Medium	$4,968,618	$5,117,094	$9,584,766	$10,188,709	$10,968,909	$10,080,811	$11,048,881	$9,791,399	$4,891,907	$5,070,303
Commercial/Industrial - Small	$3,805,763	$3,847,996	$7,497,972	$7,828,630	$8,788,535	$8,049,638	$9,110,776	$7,746,454	$3,781,567	$3,952,624
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$98,448	$94,653	$183,193	$187,048	$187,844	$187,054	$187,704	$191,237	$97,573	$98,175
Residential	$5,476,171	$5,076,468	$9,644,514	$10,020,320	$11,809,851	$10,520,995	$13,327,898	$10,144,171	$5,026,041	$5,934,341
Total	$19,373,704	$19,343,607	$37,805,581	$39,036,277	$45,063,161	$40,601,349	$48,175,403	$39,361,400	$19,140,828	$20,065,077

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2016	2017	2018	2016 JAN	2016 FEB	2016 MAR	*Program Launch* 2016 APR	2016 MAY	2016 JUN
PCIA CHARGES									
Agricultural	$192,343	$288,236	$289,462	$0	$0	$0	$13,520	$12,441	$12,754
Commercial/Industrial - Large	$5,652,490	$8,376,838	$8,412,467	$0	$0	$0	$358,362	$371,075	$354,777
Commercial/Industrial - Medium	$5,125,735	$7,927,254	$7,960,970	$0	$0	$0	$366,684	$338,420	$347,487
Commercial/Industrial - Small	$5,503,017	$8,440,957	$8,476,858	$0	$0	$0	$374,839	$359,882	$362,951
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$195,414	$301,743	$303,026	$0	$0	$0	$13,948	$13,302	$13,119
Residential	$5,588,279	$8,580,647	$8,617,143	$0	$0	$0	$412,712	$386,342	$387,720
Total	$22,257,278	$33,915,675	$34,059,926	$0	$0	$0	$1,540,067	$1,481,463	$1,478,807
RATE RELIEF									
Agricultural	$151,086	$178,568	$185,763	$0	$0	$0	$10,727	$19,099	$19,578
Commercial/Industrial - Large	$4,062,134	$4,784,775	$4,977,562	$0	$0	$0	$259,881	$520,668	$497,799
Commercial/Industrial - Medium	$3,663,826	$4,417,438	$4,595,424	$0	$0	$0	$265,916	$474,849	$487,571
Commercial/Industrial - Small	$2,892,141	$3,476,914	$3,617,005	$0	$0	$0	$199,966	$371,465	$374,632
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$67,533	$81,363	$84,641	$0	$0	$0	$4,919	$9,076	$8,951
Residential	$3,887,112	$4,796,209	$4,989,457	$0	$0	$0	$263,805	$477,809	$479,513
Total	$14,723,832	$17,735,268	$18,449,852	$0	$0	$0	$1,005,214	$1,872,965	$1,868,044
CCA REVENUE BY CLASS (NET OF PCIA & RATE RELIEF)									
Agricultural	$2,678,283	$3,104,561	$3,240,037	$0	$0	$0	$190,297	$350,441	$359,236
Commercial/Industrial - Large	$71,528,050	$82,533,887	$86,161,208	$0	$0	$0	$4,579,384	$9,521,615	$9,103,403
Commercial/Industrial - Medium	$64,486,967	$76,004,064	$79,352,085	$0	$0	$0	$4,685,721	$8,683,704	$8,916,360
Commercial/Industrial - Small	$49,447,664	$57,620,410	$60,246,235	$0	$0	$0	$3,424,511	$6,697,945	$6,755,049
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$1,087,716	$1,244,154	$1,305,158	$0	$0	$0	$79,508	$159,137	$156,950
Residential	$68,266,845	$82,547,332	$86,182,540	$0	$0	$0	$4,599,580	$8,692,022	$8,723,023
Total	$257,495,525	$303,054,408	$316,487,262	$0	$0	$0	$17,559,002	$34,104,864	$34,014,021
Cash Flow Analysis									
REVENUE FROM OPERATIONS									
Revenue - Electricity	$223,340,953	$301,911,382	$315,109,053	$0	$0	$0	$0	$0	$20,746,079
Less Uncollectible Accounts	$1,111,149	$1,502,047	$1,567,707	$0	$0	$0	$0	$0	-$103,214
Total Operational Revenue	**$222,229,804**	**$300,409,336**	**$313,541,346**	**$0**	**$0**	**$0**	**$0**	**$0**	**$20,642,864**
COST OF OPERATIONS									
Wholesale Commodity	$142,008,621	$224,718,884	$234,681,466	$0	$0	$0	$0	$0	$15,240,591
Net Energy Metering Program	$643,554	$766,776	$794,166	$0	$0	$0	$0	$0	$61,957
Retail Services (EDI/ Billing/ Customer Care)	$3,204,531	$4,132,566	$4,132,566	$0	$0	$0	$386,702	$368,661	$356,100
Services									
Personnel	$4,500,000	$4,657,500	$4,820,513	$375,000	$375,000	$375,000	$375,000	$375,000	$375,000
Outreach & Communications	$1,050,000	$1,086,750	$1,124,786	$87,500	$87,500	$87,500	$87,500	$87,500	$87,500
Other Professional Services	$2,625,000	$2,716,875	$2,811,966	$218,750	$218,750	$218,750	$218,750	$218,750	$218,750
General & Administration	$825,000	$853,875	$883,761	$68,750	$68,750	$68,750	$68,750	$68,750	$68,750
Programs	$3,000,000	$3,105,000	$3,213,675	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
SDG&E Fees	$2,009,574	$1,928,531	$1,928,531	$0	$0	$463,623	$201,989	$187,031	$170,048
Monthly Billing Fees	$534,089	$688,761	$688,761	$0	$0	$0	$64,450	$61,444	$59,350
CCASR	$511,967	$0	$0	$0	$0	$461,464	$21,528	$14,989	$3,868
Miscellaneous	$963,518	$1,239,770	$1,239,770	$0	$0	$2,159	$116,010	$110,598	$106,830
Total Operational Expenses	**$159,866,279**	**$243,966,757**	**$254,391,429**	**$1,000,000**	**$1,000,000**	**$1,463,623**	**$1,588,691**	**$1,555,692**	**$16,828,697**
CASH FLOWS FROM OPERATING ACTIVITIES	**$62,363,525**	**$56,442,579**	**$59,149,917**	**-$1,000,000**	**-$1,000,000**	**-$1,463,623**	**-$1,588,691**	**-$1,555,692**	**$3,814,168**
FINANCING									
Deposit from Financing	$50,000,000	$0	$0	$50,000,000	$0	$0	$0	$0	$0
Debt Service									
Principal	$37,500,000	$12,500,000	$0	$0	$0	$0	$0	$0	$0
Interest	$2,031,250	$20,833	$0	$208,333	$208,333	$208,333	$208,333	$208,333	$208,333
Total Debt Service	$39,531,250	$12,520,833	$0	$208,333	$208,333	$208,333	$208,333	$208,333	$208,333
CASH FLOWS NON-CAP FINANCING ACTIVITIES	**$10,468,750**	**-$12,520,833**	**$0**	**$49,791,667**	**-$208,333**	**-$208,333**	**-$208,333**	**-$208,333**	**-$208,333**
NET CASH FLOW	**$72,832,275**	**$43,921,746**	**$59,149,917**	**$48,791,667**	**-$1,208,333**	**-$1,671,956**	**-$1,797,024**	**-$1,764,026**	**$3,605,834**

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2016 JUL	2016 AUG	2016 SEP	2016 OCT	2016 NOV	2016 DEC	2017 JAN	2017 FEB	2017 MAR	2017 APR
PCIA CHARGES										
Agricultural	$28,274	$25,548	$28,426	$26,568	$24,220	$20,593	$21,583	$20,843	$21,694	$24,079
Commercial/Industrial - Large	$865,185	$760,049	$936,241	$733,635	$657,794	$615,372	$618,124	$600,854	$617,529	$638,235
Commercial/Industrial - Medium	$738,611	$675,320	$737,099	$650,055	$626,433	$645,627	$665,843	$635,531	$634,106	$653,055
Commercial/Industrial - Small	$804,472	$733,048	$826,238	$699,118	$658,280	$684,189	$706,161	$669,621	$660,253	$667,580
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$26,012	$25,769	$25,751	$26,109	$25,695	$25,708	$27,668	$19,546	$25,838	$24,842
Residential	$784,470	$695,265	$877,099	$664,357	$634,895	$745,418	$873,901	$738,599	$689,419	$639,098
Total	$3,247,023	$2,915,000	$3,430,854	$2,799,842	$2,627,317	$2,736,907	$2,913,280	$2,684,996	$2,648,839	$2,646,890
RATE RELIEF										
Agricultural	$21,783	$19,683	$21,901	$20,469	$9,644	$8,200	$8,893	$8,588	$8,939	$9,922
Commercial/Industrial - Large	$609,262	$535,225	$659,299	$516,624	$239,408	$223,968	$232,790	$226,286	$232,566	$240,364
Commercial/Industrial - Medium	$520,128	$475,559	$519,063	$457,767	$227,994	$234,980	$250,761	$239,346	$238,809	$245,945
Commercial/Industrial - Small	$416,738	$379,739	$428,013	$362,162	$176,245	$183,182	$195,637	$185,513	$182,918	$184,948
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$8,907	$8,824	$8,818	$8,941	$4,548	$4,550	$5,067	$3,580	$4,732	$4,549
Residential	$560,004	$496,324	$626,129	$474,260	$234,245	$275,023	$333,635	$281,980	$263,204	$243,993
Total	$2,136,823	$1,915,354	$2,263,223	$1,840,223	$892,084	$929,902	$1,026,782	$945,292	$931,167	$929,720
CCA REVENUE BY CLASS (NET OF PCIA & RATE RELIEF)										
Agricultural	$385,608	$348,438	$387,686	$362,350	$159,019	$135,207	$147,382	$142,332	$148,145	$164,431
Commercial/Industrial - Large	$10,710,788	$9,409,224	$11,590,438	$9,082,220	$3,890,956	$3,640,020	$3,804,883	$3,698,580	$3,801,219	$3,928,676
Commercial/Industrial - Medium	$9,143,822	$8,360,296	$9,125,104	$8,047,523	$3,705,450	$3,818,986	$4,098,621	$3,912,034	$3,903,262	$4,019,903
Commercial/Industrial - Small	$7,113,554	$6,481,989	$7,306,018	$6,181,961	$2,690,374	$2,796,263	$3,010,934	$2,855,133	$2,815,190	$2,846,431
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$143,226	$141,891	$141,792	$143,764	$60,708	$60,739	$68,603	$48,466	$64,065	$61,596
Residential	$9,855,609	$8,734,895	$11,019,349	$8,346,585	$3,815,765	$4,480,017	$5,465,158	$4,619,014	$4,311,451	$3,996,760
Total	$37,352,608	$33,476,734	$39,570,388	$32,164,403	$14,322,273	$14,931,233	$16,595,580	$15,275,558	$15,043,332	$15,017,796
Cash Flow Analysis										
REVENUE FROM OPERATIONS										
Revenue - Electricity	$32,089,488	$35,092,392	$35,710,805	$35,890,911	$36,468,322	$27,342,956	$16,657,779	$15,390,364	$15,973,052	$15,359,265
Less Uncollectible Accounts	-$159,649	-$174,589	-$177,666	-$178,562	-$181,434	-$136,035	-$82,875	-$76,569	-$79,468	-$76,414
Total Operational Revenue	**$31,929,839**	**$34,917,803**	**$35,533,139**	**$35,712,349**	**$36,286,888**	**$27,206,921**	**$16,574,905**	**$15,313,795**	**$15,893,584**	**$15,282,850**
COST OF OPERATIONS										
Wholesale Commodity	$14,955,390	$14,623,399	$26,804,700	$26,679,174	$26,546,623	$17,158,745	$15,529,168	$15,929,065	$16,812,930	$15,666,638
Net Energy Metering Program	$118,054	$132,337	$117,372	$102,159	$67,698	$43,976	$16,146	$6,436	$7,128	$15,727
Retail Services (EDI/ Billing/ Customer Care)	$352,859	$351,044	$349,587	$347,900	$346,815	$344,865	$344,381	$344,381	$344,381	$344,381
Services										
Personnel	$375,000	$375,000	$375,000	$375,000	$375,000	$375,000	$388,125	$388,125	$388,125	$388,125
Outreach & Communications	$87,500	$87,500	$87,500	$87,500	$87,500	$87,500	$90,563	$90,563	$90,563	$90,563
Other Professional Services	$218,750	$218,750	$218,750	$218,750	$218,750	$218,750	$226,406	$226,406	$226,406	$226,406
General & Administration	$68,750	$68,750	$68,750	$68,750	$68,750	$68,750	$71,156	$71,156	$71,156	$71,156
Programs	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$258,750	$258,750	$258,750	$258,750
SDG&E Fees	$166,833	$165,558	$165,154	$163,647	$164,174	$161,515	$160,711	$160,711	$160,711	$160,711
Monthly Billing Fees	$58,810	$58,507	$58,265	$57,983	$57,803	$57,478	$57,397	$57,397	$57,397	$57,397
CCASR	$2,166	$1,738	$2,014	$1,294	$2,327	$578	$0	$0	$0	$0
Miscellaneous	$105,858	$105,313	$104,876	$104,370	$104,045	$103,460	$103,314	$103,314	$103,314	$103,314
Total Operational Expenses	**$16,593,135**	**$16,272,338**	**$28,436,814**	**$28,292,880**	**$28,125,310**	**$18,709,101**	**$17,085,405**	**$17,475,592**	**$18,360,150**	**$17,222,456**
CASH FLOWS FROM OPERATING ACTIVITIES	**$15,336,704**	**$18,645,466**	**$7,096,326**	**$7,419,469**	**$8,161,578**	**$8,497,821**	**-$510,500**	**-$2,161,797**	**-$2,466,565**	**-$1,939,606**
FINANCING										
Deposit from Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service										
Principal	$0	$7,500,000	$7,500,000	$7,500,000	$7,500,000	$7,500,000	$7,500,000	$5,000,000	$0	$0
Interest	$208,333	$177,083	$145,833	$114,583	$83,333	$52,083	$20,833	$0	$0	$0
Total Debt Service	$208,333	$7,677,083	$7,645,833	$7,614,583	$7,583,333	$7,552,083	$7,520,833	$5,000,000	$0	$0
CASH FLOWS NON-CAP FINANCING ACTIVITIES	**-$208,333**	**-$7,677,083**	**-$7,645,833**	**-$7,614,583**	**-$7,583,333**	**-$7,552,083**	**-$7,520,833**	**-$5,000,000**	**$0**	**$0**
NET CASH FLOW	**$15,128,371**	**$10,968,382**	**-$549,508**	**-$195,114**	**$578,245**	**$945,737**	**-$8,031,334**	**-$7,161,797**	**-$2,466,565**	**-$1,939,606**

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2017 MAY	2017 JUN	2017 JUL	2017 AUG	2017 SEP	2017 OCT	2017 NOV	2017 DEC	2018 JAN	2018 FEB
PCIA CHARGES										
Agricultural	$23,242	$24,666	$27,695	$25,155	$28,105	$26,396	$24,138	$20,639	$21,675	$20,932
Commercial/Industrial - Large	$693,214	$686,144	$847,495	$748,355	$925,679	$728,878	$655,571	$616,760	$620,753	$603,410
Commercial/Industrial - Medium	$632,210	$672,046	$723,508	$664,930	$728,783	$645,840	$624,316	$647,083	$668,675	$638,234
Commercial/Industrial - Small	$672,305	$701,953	$788,023	$721,770	$816,917	$694,585	$656,055	$685,732	$709,165	$672,469
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$24,849	$25,372	$25,480	$25,373	$25,461	$25,940	$25,608	$25,766	$27,785	$19,629
Residential	$627,538	$651,991	$768,430	$684,568	$867,204	$660,049	$632,750	$747,100	$877,618	$741,741
Total	$2,673,358	$2,762,172	$3,180,632	$2,870,151	$3,392,150	$2,781,688	$2,618,439	$2,743,080	$2,925,671	$2,696,415
RATE RELIEF										
Agricultural	$18,529	$19,664	$22,080	$20,054	$22,406	$21,044	$9,946	$8,504	$9,251	$8,934
Commercial/Industrial - Large	$505,129	$499,977	$617,550	$545,309	$674,521	$531,116	$246,893	$232,276	$242,169	$235,403
Commercial/Industrial - Medium	$460,677	$489,704	$527,203	$484,518	$531,047	$470,608	$235,122	$243,696	$260,865	$248,989
Commercial/Industrial - Small	$360,378	$376,271	$422,407	$386,893	$437,895	$372,321	$181,755	$189,977	$203,519	$192,988
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$8,805	$8,990	$9,028	$8,990	$9,022	$9,191	$4,690	$4,719	$5,271	$3,724
Residential	$463,549	$481,611	$567,622	$505,675	$640,585	$487,564	$241,569	$285,225	$347,077	$293,341
Total	$1,817,066	$1,876,218	$2,165,891	$1,951,441	$2,315,476	$1,891,844	$919,974	$964,397	$1,068,153	$983,380
CCA REVENUE BY CLASS (NET OF PCIA & RATE RELIEF)										
Agricultural	$328,810	$348,951	$391,816	$355,877	$397,614	$373,432	$164,830	$140,940	$154,098	$148,818
Commercial/Industrial - Large	$8,904,231	$8,813,423	$10,885,950	$9,612,512	$11,890,211	$9,362,325	$4,035,393	$3,796,485	$3,980,464	$3,869,256
Commercial/Industrial - Medium	$8,120,650	$8,632,338	$9,293,358	$8,540,921	$9,361,114	$8,295,718	$3,843,000	$3,983,144	$4,287,758	$4,092,560
Commercial/Industrial - Small	$6,174,883	$6,447,193	$7,237,715	$6,629,202	$7,503,093	$6,379,518	$2,797,292	$2,923,826	$3,157,698	$2,994,303
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$142,444	$145,441	$146,060	$145,446	$145,951	$148,698	$63,496	$63,888	$72,364	$51,123
Residential	$8,179,884	$8,498,619	$10,016,389	$8,923,261	$11,303,904	$8,603,662	$3,957,058	$4,672,172	$5,716,853	$4,831,740
Total	$31,850,902	$32,885,966	$37,971,289	$34,207,220	$40,601,887	$33,163,354	$14,861,068	$15,580,456	$17,369,235	$15,987,800
Cash Flow Analysis										
REVENUE FROM OPERATIONS										
Revenue - Electricity	$15,062,651	$20,406,944	$30,161,395	$34,388,202	$36,155,644	$36,704,284	$37,453,260	$28,198,542	$17,287,114	$16,066,137
Less Uncollectible Accounts	-$74,939	-$101,527	-$150,057	-$171,086	-$179,879	-$182,608	-$186,335	-$140,291	-$86,006	-$79,931
Total Operational Revenue	**$14,987,713**	**$20,305,417**	**$30,011,339**	**$34,217,116**	**$35,975,765**	**$36,521,676**	**$37,266,926**	**$28,058,250**	**$17,201,109**	**$15,986,206**
COST OF OPERATIONS										
Wholesale Commodity	$15,108,782	$14,475,286	$14,826,003	$14,946,628	$27,917,758	$27,854,924	$28,015,881	$17,635,821	$15,979,171	$16,860,384
Net Energy Metering Program	$33,864	$70,562	$126,812	$141,333	$125,241	$107,675	$70,353	$45,498	$16,704	$6,661
Retail Services (EDI/ Billing/ Customer Care)	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381
Services										
Personnel	$388,125	$388,125	$388,125	$388,125	$388,125	$388,125	$388,125	$388,125	$401,709	$401,709
Outreach & Communications	$90,563	$90,563	$90,563	$90,563	$90,563	$90,563	$90,563	$90,563	$93,732	$93,732
Other Professional Services	$226,406	$226,406	$226,406	$226,406	$226,406	$226,406	$226,406	$226,406	$234,330	$234,330
General & Administration	$71,156	$71,156	$71,156	$71,156	$71,156	$71,156	$71,156	$71,156	$73,647	$73,647
Programs	$258,750	$258,750	$258,750	$258,750	$258,750	$258,750	$258,750	$258,750	$267,806	$267,806
SDG&E Fees	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711
Monthly Billing Fees	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397
CCASR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314
Total Operational Expenses	**$16,682,738**	**$16,085,940**	**$16,492,907**	**$16,628,053**	**$29,583,091**	**$29,502,690**	**$29,626,325**	**$19,221,410**	**$17,572,191**	**$18,443,361**
CASH FLOWS FROM OPERATING ACTIVITIES	**-$1,695,025**	**$4,219,477**	**$13,518,432**	**$17,589,063**	**$6,392,674**	**$7,018,986**	**$7,640,600**	**$8,836,840**	**-$371,082**	**-$2,457,155**
FINANCING										
Deposit from Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service										
Principal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Debt Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CASH FLOWS NON-CAP FINANCING ACTIVITIES	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NET CASH FLOW	**-$1,695,025**	**$4,219,477**	**$13,518,432**	**$17,589,063**	**$6,392,674**	**$7,018,986**	**$7,640,600**	**$8,836,840**	**-$371,082**	**-$2,457,155**

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2018 MAR	2018 APR	2018 MAY	2018 JUN	2018 JUL	2018 AUG	2018 SEP	2018 OCT	2018 NOV	2018 DEC
PCIA CHARGES										
Agricultural	$21,787	$24,182	$23,341	$24,770	$27,813	$25,262	$28,225	$26,508	$24,240	$20,727
Commercial/Industrial - Large	$620,155	$640,949	$696,162	$689,063	$851,100	$751,538	$929,616	$731,978	$658,360	$619,383
Commercial/Industrial - Medium	$636,803	$655,833	$634,899	$674,905	$726,586	$667,758	$731,883	$648,587	$626,972	$649,836
Commercial/Industrial - Small	$663,061	$670,419	$675,164	$704,939	$791,375	$724,840	$820,391	$697,539	$658,846	$688,648
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$25,948	$24,948	$24,955	$25,480	$25,588	$25,481	$25,569	$26,051	$25,717	$25,876
Residential	$692,351	$641,817	$630,207	$654,764	$771,698	$687,480	$870,893	$662,857	$635,441	$750,277
Total	$2,660,105	$2,658,147	$2,684,729	$2,773,920	$3,194,160	$2,882,358	$3,406,577	$2,793,519	$2,629,576	$2,754,747
RATE RELIEF										
Agricultural	$9,299	$10,321	$19,276	$20,456	$22,969	$20,862	$23,309	$21,891	$10,346	$8,847
Commercial/Industrial - Large	$241,936	$250,048	$525,481	$520,122	$642,432	$567,280	$701,698	$552,516	$256,841	$241,635
Commercial/Industrial - Medium	$248,431	$255,855	$479,238	$509,435	$548,445	$504,041	$552,444	$489,570	$244,595	$253,515
Commercial/Industrial - Small	$190,288	$192,400	$374,899	$391,431	$439,427	$402,482	$455,539	$387,323	$189,078	$197,631
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$4,922	$4,733	$9,160	$9,352	$9,392	$9,353	$9,385	$9,562	$4,879	$4,909
Residential	$273,809	$253,823	$482,226	$501,016	$590,493	$526,050	$666,395	$507,209	$251,302	$296,717
Total	$968,685	$967,180	$1,890,279	$1,951,814	$2,253,158	$2,030,067	$2,408,770	$1,968,070	$957,041	$1,003,254
CCA REVENUE BY CLASS (NET OF PCIA & RATE RELIEF)										
Agricultural	$154,895	$171,924	$342,896	$363,900	$408,602	$371,123	$414,647	$389,430	$172,341	$147,363
Commercial/Industrial - Large	$3,976,631	$4,109,970	$9,287,980	$9,193,258	$11,355,106	$10,026,786	$12,402,648	$9,765,817	$4,221,611	$3,971,679
Commercial/Industrial - Medium	$4,083,384	$4,205,407	$8,470,629	$9,004,369	$9,693,878	$8,909,013	$9,764,554	$8,653,242	$4,020,340	$4,166,952
Commercial/Industrial - Small	$2,952,414	$2,985,177	$6,447,909	$6,732,259	$7,557,734	$6,922,316	$7,834,846	$6,661,592	$2,933,643	$3,066,345
Outdoor Lighting - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outdoor Lighting - Small Commercial	$67,578	$64,973	$149,078	$152,215	$152,864	$152,221	$152,749	$155,624	$66,977	$67,391
Residential	$4,510,012	$4,180,828	$8,532,081	$8,864,540	$10,447,660	$9,307,465	$11,790,611	$8,974,106	$4,139,298	$4,887,346
Total	$15,744,914	$15,718,279	$33,230,573	$34,310,542	$39,615,843	$35,688,924	$42,360,055	$34,599,811	$15,554,210	$16,307,076
Cash Flow Analysis										
REVENUE FROM OPERATIONS										
Revenue - Electricity	$16,712,105	$16,075,447	$15,765,143	$21,324,876	$31,473,901	$35,877,745	$37,721,650	$38,293,959	$39,075,264	$29,435,712
Less Uncollectible Accounts	-$83,145	-$79,977	-$78,434	-$106,094	-$156,587	-$178,496	-$187,670	-$190,517	-$194,404	-$146,446
Total Operational Revenue	**$16,628,960**	**$15,995,469**	**$15,686,709**	**$21,218,782**	**$31,317,315**	**$35,699,249**	**$37,533,980**	**$38,103,441**	**$38,880,860**	**$29,289,266**
COST OF OPERATIONS										
Wholesale Commodity	$18,154,178	$16,726,171	$15,593,622	$15,261,858	$16,519,793	$17,483,298	$29,110,222	$27,690,791	$28,213,001	$17,088,979
Net Energy Metering Program	$7,382	$16,288	$35,072	$73,083	$131,347	$146,389	$129,721	$111,526	$72,869	$47,125
Retail Services (EDI/ Billing/ Customer Care)	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381	$344,381
Services										
Personnel	$401,709	$401,709	$401,709	$401,709	$401,709	$401,709	$401,709	$401,709	$401,709	$401,709
Outreach & Communications	$93,732	$93,732	$93,732	$93,732	$93,732	$93,732	$93,732	$93,732	$93,732	$93,732
Other Professional Services	$234,330	$234,330	$234,330	$234,330	$234,330	$234,330	$234,330	$234,330	$234,330	$234,330
General & Administration	$73,647	$73,647	$73,647	$73,647	$73,647	$73,647	$73,647	$73,647	$73,647	$73,647
Programs	$267,806	$267,806	$267,806	$267,806	$267,806	$267,806	$267,806	$267,806	$267,806	$267,806
SDG&E Fees	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711	$160,711
Monthly Billing Fees	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397	$57,397
CCASR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314	$103,314
Total Operational Expenses	**$19,737,876**	**$18,318,775**	**$17,205,010**	**$16,911,257**	**$18,227,456**	**$19,206,003**	**$30,816,260**	**$29,378,634**	**$29,862,186**	**$18,712,420**
CASH FLOWS FROM OPERATING ACTIVITIES	**-$3,108,917**	**-$2,323,306**	**-$1,518,300**	**$4,307,526**	**$13,089,858**	**$16,493,246**	**$6,717,720**	**$8,724,807**	**$9,018,674**	**$10,576,846**
FINANCING										
Deposit from Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service										
Principal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Debt Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CASH FLOWS NON-CAP FINANCING ACTIVITIES	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NET CASH FLOW	**-$3,108,917**	**-$2,323,306**	**-$1,518,300**	**$4,307,526**	**$13,089,858**	**$16,493,246**	**$6,717,720**	**$8,724,807**	**$9,018,674**	**$10,576,846**

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2016	2017	2018	2016 JAN	2016 FEB	2016 MAR	*Program Launch* 2016 APR	2016 MAY	2016 JUN
FUND BALANCE	**$72,832,275**	**$116,754,021**	**$175,903,938**	**$48,791,667**	**$47,583,333**	**$45,911,377**	**$44,114,353**	**$42,350,328**	**$45,956,162**
Less Outstanding Debt	$12,500,000	$0	$0	$50,000,000	$50,000,000	$50,000,000	$50,000,000	$50,000,000	$50,000,000
Net Worth (Simplified)	$60,332,275	$116,754,021	$175,903,938	-$1,208,333	-$2,416,667	-$4,088,623	-$5,885,647	-$7,649,672	-$4,043,838
Summary & Financial Metrics									
FINANCIAL METRICS									
EBITDA	$74,863,525	$43,942,579	$59,149,917	$49,000,000	-$1,000,000	-$1,463,623	-$1,588,691	-$1,555,692	$3,814,168
Debt Service Capacity Ratio				235	(5)	(7)	(8)	(7)	18
Debt Service Capacity Ratio - 12 Months	37	2,109	-						
SUMMARY METRICS ($/KWH)									
Cost Of Energy	$0.066	$0.067	$0.069						
Cost Of Energy Sold	$0.074	$0.073	$0.075						
Average Retail Rate	$0.097	$0.089	$0.093						
PCIA Charges (Reimbursed)	$0.008	$0.010	$0.010						
Customer Savings	$0.006	$0.005	$0.005						
Cash Flow by Account									
SUPPLIER RESERVE AMOUNT				$0	$0	$0	$18,726,574	$18,726,574	$18,726,574
COLLATERAL REQUIREMENTS									
Supplier Collateral Requirement				$18,726,574	$18,726,574	$18,726,574	$18,726,574	$18,726,574	$18,726,574
CPUC and CAISO Bond Requirements				$600,000	$600,000	$600,000	$600,000	$600,000	$600,000
SDG&E Deposit				$231,874	$231,874	$231,874	$231,874	$231,874	$231,874
Total Other Uses				$19,558,448	$19,558,448	$19,558,448	$19,558,448	$19,558,448	$19,558,448
SECURED REVENUE ACCOUNT									
BOM Revenue Account Balance				$0	$0	$0	$0	$18,726,574	$18,726,574
Revenues, pre-disbursement				$0	$0	$0	$0	$0	$17,202,387
Cost of Energy Discharge				$0	$0	$0	$0	$0	-$15,302,549
Disbursement from/(to) Operating Account				$0	$0	$0	$18,726,574	$0	-$1,899,838
Revenues, post-dispursement				$0	$0	$0	$0	$0	$3,440,477
EOM Revenue Account Balance				$0	$0	$0	$18,726,574	$18,726,574	$22,167,051
OPERATING ACCOUNT									
BOM Operating Account Balance				$0	$865,385	$865,385	$865,385	$865,385	$865,385
Disbursement from/(to) Revenue Account				$0	$0	$0	-$18,726,574	$0	$1,899,838
Non-Energy Expenses				-$1,208,333	-$1,208,333	-$1,671,956	-$1,797,024	-$1,764,026	-$1,734,482
Disbursement from/(to) Reserve Fund				$2,073,718	$1,208,333	$1,671,956	$20,523,598	$1,764,026	-$165,357
EOM Operating Account Balance				$865,385	$865,385	$865,385	$865,385	$865,385	$865,385
RESERVE FUND									
BOM Reserve Fund Balance				$0	$28,367,834	$27,159,501	$25,487,545	$4,963,947	$3,199,922
Collateral Requirements				-$19,558,448	$0	$0	$0	$0	$0
Deposit from Financing				$50,000,000					
Disbursement from/(to) Operating Account				-$2,073,718	-$1,208,333	-$1,671,956	-$20,523,598	-$1,764,026	$165,357
EOM Reserve Fund Balance				$28,367,834	$27,159,501	$25,487,545	$4,963,947	$3,199,922	$3,365,279

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2016 JUL	2016 AUG	2016 SEP	2016 OCT	2016 NOV	2016 DEC	2017 JAN	2017 FEB	2017 MAR	2017 APR
FUND BALANCE	**$61,084,533**	**$72,052,915**	**$71,503,407**	**$71,308,293**	**$71,886,538**	**$72,832,275**	**$64,800,941**	**$57,639,144**	**$55,172,579**	**$53,232,973**
Less Outstanding Debt	$50,000,000	$42,500,000	$35,000,000	$27,500,000	$20,000,000	$12,500,000	$5,000,000	$0	$0	$0
Net Worth (Simplified)	$11,084,533	$29,552,915	$36,503,407	$43,808,293	$51,886,538	$60,332,275	$59,800,941	$57,639,144	$55,172,579	$53,232,973
Summary & Financial Metrics										
FINANCIAL METRICS										
EBITDA	$15,336,704	$11,145,466	-$403,674	-$80,531	$661,578	$997,821	-$8,010,500	-$7,161,797	-$2,466,565	-$1,939,606
Debt Service Capacity Ratio	74	1	(0)	(0)	0	0	(1)	(1)	-	-
Debt Service Capacity Ratio - 12 Months						37	10	7	7	8
SUMMARY METRICS ($/KWH)										
Cost Of Energy										
Cost Of Energy Sold										
Average Retail Rate										
PCIA Charges (Reimbursed)										
Customer Savings										
Cash Flow by Account										
SUPPLIER RESERVE AMOUNT	$18,726,574	$18,726,574	$18,726,574	$18,726,574	$18,726,574	$18,726,574	$19,556,789	$19,556,789	$19,556,789	$19,556,789
COLLATERAL REQUIREMENTS										
Supplier Collateral Requirement	$18,726,574	$18,726,574	$18,726,574	$18,726,574	$18,726,574	$18,726,574	$19,556,789	$19,556,789	$19,556,789	$19,556,789
CPUC and CAISO Bond Requirements	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000
SDG&E Deposit	$231,874	$231,874	$231,874	$231,874	$231,874	$231,874	$222,523	$222,523	$222,523	$222,523
Total Other Uses	$19,558,448	$19,558,448	$19,558,448	$19,558,448	$19,558,448	$19,558,448	$20,379,312	$20,379,312	$20,379,312	$20,379,312
SECURED REVENUE ACCOUNT										
BOM Revenue Account Balance	$22,167,051	$24,906,543	$25,484,858	$24,648,764	$25,638,641	$24,774,388	$23,992,429	$22,764,835	$21,197,553	$22,632,966
Revenues, pre-disbursement	$25,749,870	$28,159,519	$29,610,949	$28,800,281	$30,239,073	$21,941,065	$13,366,859	$13,673,032	$12,817,407	$12,735,709
Cost of Energy Discharge	-$15,073,443	-$14,755,736	-$26,922,072	-$26,781,333	-$26,614,321	-$17,202,720	-$15,545,314	-$15,935,501	-$16,820,058	-$15,682,365
Disbursement from/(to) Operating Account	-$14,116,904	-$19,583,752	-$9,447,162	-$7,941,139	-$10,536,820	-$10,786,160	-$2,257,185	-$945,577	$2,361,888	-$129,522
Revenues, post-dispursement	$6,179,969	$6,758,285	$5,922,190	$6,912,068	$6,047,815	$5,265,856	$3,208,046	$1,640,764	$3,076,178	$2,547,142
EOM Revenue Account Balance	$24,906,543	$25,484,858	$24,648,764	$25,638,641	$24,774,388	$23,992,429	$22,764,835	$21,197,553	$22,632,966	$22,103,931
OPERATING ACCOUNT										
BOM Operating Account Balance	$865,385	$865,385	$865,385	$865,385	$865,385	$865,385	$865,385	$895,673	$895,673	$895,673
Disbursement from/(to) Revenue Account	$14,116,904	$19,583,752	$9,447,162	$7,941,139	$10,536,820	$10,786,160	$2,257,185	$945,577	-$2,361,888	$129,522
Non-Energy Expenses	-$1,728,025	-$9,193,685	-$9,160,575	-$9,126,130	-$9,094,322	-$9,058,464	-$9,060,925	-$6,540,091	-$1,540,091	-$1,540,091
Disbursement from/(to) Reserve Fund	-$12,388,879	-$10,390,067	-$286,587	$1,184,992	-$1,442,497	-$1,727,696	$6,834,028	$5,594,515	$3,901,979	$1,410,570
EOM Operating Account Balance	$865,385	$865,385	$865,385	$865,385	$865,385	$865,385	$895,673	$895,673	$895,673	$895,673
RESERVE FUND										
BOM Reserve Fund Balance	$3,365,279	$15,754,158	$26,144,224	$26,430,812	$25,245,820	$26,688,317	$28,416,014	$20,761,122	$15,166,607	$11,264,628
Collateral Requirements	$0	$0	$0	$0	$0	$0	-$820,864	$0	$0	$0
Deposit from Financing										
Disbursement from/(to) Operating Account	$12,388,879	$10,390,067	$286,587	-$1,184,992	$1,442,497	$1,727,696	-$6,834,028	-$5,594,515	-$3,901,979	-$1,410,570
EOM Reserve Fund Balance	$15,754,158	$26,144,224	$26,430,812	$25,245,820	$26,688,317	$28,416,014	$20,761,122	$15,166,607	$11,264,628	$9,854,058

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2017 MAY	2017 JUN	2017 JUL	2017 AUG	2017 SEP	2017 OCT	2017 NOV	2017 DEC	2018 JAN	2018 FEB
FUND BALANCE	**$51,537,948**	**$55,757,426**	**$69,275,858**	**$86,864,921**	**$93,257,595**	**$100,276,581**	**$107,917,181**	**$116,754,021**	**$116,382,939**	**$113,925,784**
Less Outstanding Debt	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Worth (Simplified)	$51,537,948	$55,757,426	$69,275,858	$86,864,921	$93,257,595	$100,276,581	$107,917,181	$116,754,021	$116,382,939	$113,925,784
Summary & Financial Metrics										
FINANCIAL METRICS										
EBITDA	-$1,695,025	$4,219,477	$13,518,432	$17,589,063	$6,392,674	$7,018,986	$7,640,600	$8,836,840	-$371,082	-$2,457,155
Debt Service Capacity Ratio	-	-	-	-	-	-	-	-	-	-
Debt Service Capacity Ratio - 12 Months	10	13	15	37	81	186	495	2,109	-	-
SUMMARY METRICS ($/KWH)										
Cost Of Energy										
Cost Of Energy Sold										
Average Retail Rate										
PCIA Charges (Reimbursed)										
Customer Savings										
Cash Flow by Account										
SUPPLIER RESERVE AMOUNT	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,861,838	$19,861,838
COLLATERAL REQUIREMENTS										
Supplier Collateral Requirement	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,556,789	$19,861,838	$19,861,838
CPUC and CAISO Bond Requirements	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000
SDG&E Deposit	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523
Total Other Uses	$20,379,312	$20,379,312	$20,379,312	$20,379,312	$20,379,312	$20,379,312	$20,379,312	$20,379,312	$20,684,361	$20,684,361
SECURED REVENUE ACCOUNT										
BOM Revenue Account Balance	$22,103,931	$22,457,636	$22,941,025	$25,365,435	$26,179,456	$25,552,750	$26,625,500	$25,767,943	$24,987,418	$23,191,085
Revenues, pre-disbursement	$12,086,865	$16,921,181	$24,202,692	$27,594,448	$29,979,804	$29,452,964	$31,055,771	$22,627,621	$13,871,862	$14,273,398
Cost of Energy Discharge	-$15,142,646	-$14,545,848	-$14,952,815	-$15,087,961	-$28,043,000	-$27,962,599	-$28,086,234	-$17,681,319	-$15,995,874	-$16,867,045
Disbursement from/(to) Operating Account	$508,639	-$5,276,180	-$12,634,113	-$18,315,133	-$8,559,472	-$7,486,327	-$10,038,249	-$11,157,457	-$3,001,567	-$735,601
Revenues, post-dispursement	$2,900,848	$3,384,236	$5,808,646	$6,622,668	$5,995,961	$7,068,711	$6,211,154	$5,430,629	$3,329,247	$1,712,808
EOM Revenue Account Balance	$22,457,636	$22,941,025	$25,365,435	$26,179,456	$25,552,750	$26,625,500	$25,767,943	$24,987,418	$23,191,085	$21,574,646
OPERATING ACCOUNT										
BOM Operating Account Balance	$895,673	$895,673	$895,673	$895,673	$895,673	$895,673	$895,673	$895,673	$895,673	$927,022
Disbursement from/(to) Revenue Account	-$508,639	$5,276,180	$12,634,113	$18,315,133	$8,559,472	$7,486,327	$10,038,249	$11,157,457	$3,001,567	$735,601
Non-Energy Expenses	-$1,540,091	-$1,540,091	-$1,540,091	-$1,540,091	-$1,540,091	-$1,540,091	-$1,540,091	-$1,540,091	-$1,576,316	-$1,576,316
Disbursement from/(to) Reserve Fund	$2,048,731	-$3,736,089	-$11,094,022	-$16,775,042	-$7,019,381	-$5,946,235	-$8,498,157	-$9,617,365	-$1,393,902	$840,716
EOM Operating Account Balance	$895,673	$895,673	$895,673	$895,673	$895,673	$895,673	$895,673	$895,673	$927,022	$927,022
RESERVE FUND										
BOM Reserve Fund Balance	$9,854,058	$7,805,327	$11,541,416	$22,635,438	$39,410,480	$46,429,861	$52,376,096	$60,874,253	$70,491,618	$71,580,471
Collateral Requirements	$0	$0	$0	$0	$0	$0	$0	$0	-$305,049	$0
Deposit from Financing										
Disbursement from/(to) Operating Account	-$2,048,731	$3,736,089	$11,094,022	$16,775,042	$7,019,381	$5,946,235	$8,498,157	$9,617,365	$1,393,902	-$840,716
EOM Reserve Fund Balance	$7,805,327	$11,541,416	$22,635,438	$39,410,480	$46,429,861	$52,376,096	$60,874,253	$70,491,618	$71,580,471	$70,739,755

CITY OF SAN DIEGO
COMMUNITY CHOICE AGGREGATION
SHORT TERM COST OF SERVICE MODEL

	2018 MAR	2018 APR	2018 MAY	2018 JUN	2018 JUL	2018 AUG	2018 SEP	2018 OCT	2018 NOV	2018 DEC
FUND BALANCE	**$110,816,867**	**$108,493,562**	**$106,975,262**	**$111,282,787**	**$124,372,645**	**$140,865,891**	**$147,583,611**	**$156,308,418**	**$165,327,092**	**$175,903,938**
Less Outstanding Debt	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Worth (Simplified)	$110,816,867	$108,493,562	$106,975,262	$111,282,787	$124,372,645	$140,865,891	$147,583,611	$156,308,418	$165,327,092	$175,903,938
Summary & Financial Metrics										
FINANCIAL METRICS										
EBITDA	-$3,108,917	-$2,323,306	-$1,518,300	$4,307,526	$13,089,858	$16,493,246	$6,717,720	$8,724,807	$9,018,674	$10,576,846
Debt Service Capacity Ratio	-	-	-	-	-	-	-	-	-	-
Debt Service Capacity Ratio - 12 Months	-	-	-	-	-	-	-	-	-	-
SUMMARY METRICS ($/KWH)										
Cost Of Energy										
Cost Of Energy Sold										
Average Retail Rate										
PCIA Charges (Reimbursed)										
Customer Savings										
Cash Flow by Account										
SUPPLIER RESERVE AMOUNT	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838
COLLATERAL REQUIREMENTS										
Supplier Collateral Requirement	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838	$19,861,838
CPUC and CAISO Bond Requirements	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000	$600,000
SDG&E Deposit	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523	$222,523
Total Other Uses	$20,684,361	$20,684,361	$20,684,361	$20,684,361	$20,684,361	$20,684,361	$20,684,361	$20,684,361	$20,684,361	$20,684,361
SECURED REVENUE ACCOUNT										
BOM Revenue Account Balance	$21,574,646	$23,080,346	$22,527,750	$22,897,975	$23,398,302	$25,923,254	$26,771,370	$26,117,501	$27,236,698	$26,341,981
Revenues, pre-disbursement	$13,410,451	$13,329,558	$12,650,572	$17,682,319	$25,255,899	$28,789,717	$31,278,316	$30,728,582	$32,400,717	$23,620,376
Cost of Energy Discharge	-$18,161,560	-$16,742,459	-$15,628,693	-$15,334,940	-$16,651,140	-$17,629,686	-$29,239,943	-$27,802,318	-$28,285,870	-$17,136,103
Disbursement from/(to) Operating Account	$3,038,301	$194,392	$312,209	-$5,383,516	-$12,141,222	-$17,221,446	-$8,947,905	-$9,181,927	-$11,489,706	-$12,964,416
Revenues, post-dispursement	$3,218,508	$2,665,912	$3,036,137	$3,536,464	$6,061,416	$6,909,532	$6,255,663	$7,374,860	$6,480,143	$5,668,890
EOM Revenue Account Balance	$23,080,346	$22,527,750	$22,897,975	$23,398,302	$25,923,254	$26,771,370	$26,117,501	$27,236,698	$26,341,981	$25,530,728
OPERATING ACCOUNT										
BOM Operating Account Balance	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022
Disbursement from/(to) Revenue Account	-$3,038,301	-$194,392	-$312,209	$5,383,516	$12,141,222	$17,221,446	$8,947,905	$9,181,927	$11,489,706	$12,964,416
Non-Energy Expenses	-$1,576,316	-$1,576,316	-$1,576,316	-$1,576,316	-$1,576,316	-$1,576,316	-$1,576,316	-$1,576,316	-$1,576,316	-$1,576,316
Disbursement from/(to) Reserve Fund	$4,614,617	$1,770,709	$1,888,526	-$3,807,199	-$10,564,906	-$15,645,130	-$7,371,588	-$7,605,611	-$9,913,390	-$11,388,099
EOM Operating Account Balance	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022	$927,022
RESERVE FUND										
BOM Reserve Fund Balance	$70,739,755	$66,125,138	$64,354,430	$62,465,904	$66,273,103	$76,838,009	$92,483,139	$99,854,727	$107,460,338	$117,373,728
Collateral Requirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deposit from Financing										
Disbursement from/(to) Operating Account	-$4,614,617	-$1,770,709	-$1,888,526	$3,807,199	$10,564,906	$15,645,130	$7,371,588	$7,605,611	$9,913,390	$11,388,099
EOM Reserve Fund Balance	$66,125,138	$64,354,430	$62,465,904	$66,273,103	$76,838,009	$92,483,139	$99,854,727	$107,460,338	$117,373,728	$128,761,827

APPENDIX F

SAMPLE CCA RISK MATRIX, PREPARED FOR THE CITY OF BENICIA

In 2014, the City of Benicia retained MRW & Associates, LLC to examine the risks associated with joining MCE and review the “Marin Clean Energy Applicant Analysis for the City of Benicia” as part of its due diligence related to participation in MCE.

Description of Risk	Magnitude or Importance of Risk
Procurement Risks	
Volume Risk: Uncertainty in load can cause under- or over-procurement	Medium
Future Price Risk: MCE cannot procure power for incremental customers at competitive costs	Medium
Expansion of CCA: Can current contract accommodate all new customers?	Low
Contract Renewal: MCE cannot procure power at competitive prices at end of current agreement	High
Regulatory and Policy Risks	
Adverse CPUC Decisions: Exit Fees and bonding costs may be higher than expected	Medium
MCE’s lack of low-income ratepayer policy	Low
Benicia’s interests may not always align with that of other JPA members	Medium
Customer Cost Risks	
PG&E Exit Fees: Who bears risk of changes in exit fees?	High
Uncertainty in Departing Load Fees: How much must customers pay to exit CCA after opt-out period ends?	Low
MCE Pricing Commitment: Will MCE meet or beat PG&E’s rates?	High
MCE Pricing Commitment: Will MCE guarantee CARE customers won’t pay more with MCE than they would have with PG&E?†	High

City-Specific Risks	
Supplier Guarantees: City must provide guarantees to power suppliers	Low
New Generation Guarantees: City must provide support to obtain financing for new generation	Low
Financial liability if MCE fails	Low

APPENDIX B

PRIORITY GUIDING PRINCIPLES: CITY OF SAN DIEGO COMMUNITY CHOICE AGGREGATION (CCA) FEASIBILITY STUDY

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APPENDIX B

PRIORITY GUIDING PRINCIPLES: CITY OF SAN DIEGO COMMUNITY CHOICE AGGREGATION (CCA) FEASIBILITY STUDY

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Priority Guiding Principles:
City of San Diego Community Choice Aggregation (CCA) Feasibility Study
Adopted December 10, 2015 by the City of San Diego Sustainable Energy Advisory Board

<u>Recommended Guiding Principles</u>

1. Model CCA launch as an opt-out program to optimize the purchasing power of the CCA.

2. Consider available information including the third party sponsored CCA feasibility study funded by Protect Our Communities Foundation. To the extent deemed necessary, consider findings of the current CCA feasibility study funded by a third party non profit regarding the cost-benefit relative to business as usual and other relevant consumer cost competitive factors such as effect of utility stranded costs on ratepayers.

3. **Evaluate economic development potential of CCA.** The following economic development potential factors should be evaluated in the CCA feasibility study:

a) Use of local labor with an emphasis on investment in under-resourced communities;
b) Consideration for livable wage and benefits, and training and certification requirements;
c) Any impacts on current job market, and establishment of a jobs transition program for anyone negatively impacted by CCA establishment; and
d) Sourcing from local businesses and supplier contracting policy.

Evaluative criteria for power purchasing and investment should include benefit of these factors.

4. Evaluate ability of CCA to achieve greenhouse gas emission reduction targets. City of San Diego is setting forth goals to achieve state and federal requirements for greenhouse gas reductions. Achieving these goals is a critical benefit to citizens of San Diego.

5. Evaluate a resource plan that follows the state loading order with an emphasis on local implementation. The CCA program should encourage local energy efficiency programs and distributed generation renewable energy sources. The CCA program should promote and enhance consumers' ability to meet their own energy needs through investment in building- and site-based renewable energy and energy storage on homes, businesses and integrated into the utility distribution system.

6. Evaluate ability to achieve 100 percent local renewables by 2035. The CCA program should develop a strategy to make San Diego a net energy producer. The ideal is that distributed generation (rooftop and parking lot solar), energy efficiency, and compatible storage are heavily promoted to push electric energy up out of the neighborhoods into the rest of the local grid, storage, and eventually out of the City. Local energy use and generation goals will be set and data will be monitored by official community planning area and customer class to measure progress in achievement of goals and to ensure incentives and resources are provided equitably to all communities throughout the city.

7. Evaluate a business and implementation phase-in plan to achieve targets identified to the Recommended Minimum Performance Table (below). Evaluate plans similar to "Sonoma Clean Power" CCA that phase-in geographic areas, customers use groups and locally generated renewable energy resources to achieve the goal of producing all CCA energy from renewables generated within and on developed land or land designated for urban development within the City of San Diego CCA boundary.

Recommended Minimum Performance Criteria

The table below is an evaluative tool. It does not set up a rigid pass fail criteria, but rather establishes recommended minimum performance criteria. We propose that the table below can be used as a guidance document in defining potential CCA scenarios for evaluation. Each criterion shall be assessed for likelihood of feasibility and associated risk while showing compliance with state laws.

If the goals set forth in the table are not considered achievable at the benchmark points noted, then the feasibility study should indicate when or under what circumstances they would be able to be achieved in relation to the other goals. The primary function assigned the CCA in the CAP is to achieve 100% renewable energy by 2035. The Guiding Principles qualify the 100% renewables and greenhouse gas goal achievement with a number of additional economic and environmental goals.

Recommended Minimum Performance Table

Category	**Subcategory**	**1-3 Years**	**3-5 Years**	**5-10 Years**	**10+ Years**
Environmental	GHG Reductions		Meet CAP thresholds		Meet CAP thresholds
Environmental	Renewables Percentage	Minimize Non-Local RECs	Minimize Non-Local RECs	Minimize Non-Local RECs, On-track to have no RECs by 2035	100% Renewable Energy by 2035 not from RECs
Environmental	Local DG				50% local DG by 2035
Environmental	Energy efficiency / DR deployment			Establish program(s) to meet CAP targets and the CA Long Term Energy Efficiency Strategic Plan	
Financial	Operating reserve	Sufficient to establish operations	Enough capital to invest in local projects/programs		
Financial	Cost of purchased energy (PCIA and electricity)	Not substantially different than IOU	Not substantially different than IOU	Not substantially different than IOU	Not substantially different than IOU
Economic	Impact on Markets and Jobs (labor, home builders, solar - big & small, energy storage)	No negative effect on local jobs	Positive impact on local jobs	Substantial positive impact local jobs by 2035	Substantial positive impact local jobs by 2035
Economic	Rates to consumer (social cost)	Baseline offering not more than IOU	Baseline offering not more than IOU	Program should show high likelihood of reduced rates for baseline offering	Program should show high likelihood of reduced rates for baseline offering

APPENDIX C

CCA REGULATORY AND TECHNICAL INFORMATION

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APPENDIX C

CCA REGULATORY AND TECHNICAL INFORMATION

CCAs were authorized by Assembly Bill (AB) 117[a] with additional details codified in California Public Utilities Commission (CPUC) Code Section 366.2(c)(3)[b]. AB 117 authorized customers to aggregate their electrical loads as members of their local community with community choice aggregators. Section 366.2(c)(3) provided additional guidance with regulatory oversight provided by the CPUC. A summary of key requirements of Section 366.2(c)(3) is provided in the Table C-1 below.

Table C-1: CPUC Code Section 366.2(c)(3) Requirements

Customers may aggregate their loads through a public process with community choice aggregators, if each customer is given an opportunity to opt-out of his or her community's aggregation program.
The implementation of a CCA program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.
A CCA shall be solely responsible for all generation procurement activities on behalf of the CCA's customers
If a public agency seeks to serve as a CCA, it shall offer the opportunity to purchase electricity to all residential customers within its jurisdiction.
Under a CCA, customer participation may not require a positive written declaration, but each customer shall be informed of his or her right to opt-out of the CCA.
A CCA establishing electrical load aggregation pursuant to this section shall develop an implementation plan detailing the process and consequences of aggregation.
All electrical corporations shall cooperate fully with any CCAs that investigate, pursue, or implement CCA programs.
An entity authorized to be a CCA that elects to implement a CCA program within its jurisdiction pursuant to this chapter, shall do so by ordinance.
Two or more entities authorized to be a CCA, may participate as a group in a CCA program pursuant to this chapter, through a joint powers agency[c]

[a] 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

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

[c] Joint Powers Agency may be established pursuant to Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code

A CCA shall have an operating service agreement with the electrical corporation prior to furnishing electric service to consumers within its jurisdiction.
The CCA shall register with the CPUC, which may require additional information to ensure compliance with basic consumer protection rules and other procedural matters.
An electrical corporation shall recover from the CCA any costs reasonably attributable to the CCA, as determined by the CPUC
Nothing in this subdivision is intended to modify, or prohibit the use of, charges funding programs for the benefit of low-income customers.

For the City CCA program, the formal SDG&E relationship is contractually-based after implementation of CCA Service Agreements with SDG&E. Additionally, the services provided by SDG&E to the CCA have fees associated with them.[d] IOUs have specific documented rules and processes that define their relationships with CCAs that were developed to satisfy both their legislative and regulatory responsibilities. SDG&E has posted[e] their CCA rules and other CCA information including:

- SDG&E Rule 27 Community Choice Aggregation Rules[f]
- Community Choice Aggregation Cost Responsibility Surcharge (CRS)[g]
- Community Choice Aggregation Open Season[h]
- Transportation of Electric Power for Community Choice Aggregation Customer[i]
- Information Release to Community Choice Aggregator[j]
- Frequently asked questions about San Diego Gas & Electric and community choice aggregation[k]

The City CCA program will be required to understand these rules and follow the prescribed processes to ensure that the establishment of the CCA proceeds smoothly.

IOU CODE OF CONDUCT REGARDING CCAs

The CPUC has also established a Code of Conduct[l] governing the treatment of CCAs by IOUs, committing the CPUC to expedited resolution of CCA complaints and requiring collaborative comparison of retail

[d] SDG&E Schedule CCA Transportation of Electric Power for Community Choice Aggregation Customers: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CCA.pdf

[e] SDG&E CCA Homepage: http://www.sdge.com/community-choice-aggregation

[f] Rule 27 Community Choice Aggregation Rules: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE27.pdf

[g] Schedule CCA-CRS Community Choice Aggregation Cost Responsibility Surcharge: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CCA-CRS.pdf

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

[i] Schedule CCA Transportation of Electric Power for Community Choice Aggregation Customer: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CCA.pdf

[j] Schedule CCA-INFO Information Release to Community Choice Aggregator: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CCA-INFO.pdf

[k] Frequently asked questions about San Diego Gas & Electric and community choice aggregation: http://www.sdge.com/sites/default/files/documents/954815352/community-choice-aggregation-faq.pdf?nid=4166

[l] Decision 12-12-036, December 20, 2012 - Decision Adopting a Code of Conduct and Enforcement Mechanisms Related to Utility Interactions with Community Choice Aggregators, Pursuant to Senate Bill 790: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=2572

electricity rates. These rules and procedures were intended to provide CCAs the ability to compete on an equal basis with other LSEs, and to prevent IOUs from using their position or market power to undermine the CCAs. The Code of Conduct rules are summarized in the Table C-2 below.

Table C-2: Summary of CPUC's IOU Code of Conduct Regarding CCAs

IOU Required Code of Conduct	CPUC Obligations	IOU and CCA Required Collaboration
No lobbying against a CCA except through a shareholder funded independent marketing division functionally and physically separate from the ratepayer utility operations	A complaint filed by an existing or prospective CCA alleging a violation of an electrical corporation's obligation shall be resolved in no more than 180 days following the filing of the complaint although this deadline may be extended under certain circumstances.	Jointly prepared annual neutral, complete, and accurate written comparison of IOU and CCA average tariffs for each customer class, sample bills and generation portfolio contents.
Refrain from speaking on behalf of CCA a program (or appearing to) or making any statement relating to CCA rates or terms and conditions of service that is untrue or misleading		
Shall not discriminate between own customers and those of a CCA		
May not refuse to make economic sales of excess electricity to a CCA		
Maintain a log of all complaints submitted in writing relating to services provided for the CCA and CCA customers		

CCA IMPLEMENTATION STEPS

The City CCA program will need to coordinate formation of the CCA with SDG&E. Necessary and recommended steps for the CCA to perform in collaboration with SDG&E are summarized in the Table C-3 below. Footnotes have been added to reference the rules and guidance discussed previously in this Appendix C as well as other documents and references pertinent to fulfilling these CCA implementation steps.

Table C-3: CCA Implementation Steps

CCA Implementation Steps
1. Sign a CCA Non-Disclosure Agreement (this was completed by the City to facilitate this Study)
2. Pass local ordinance authorizing CCA
3. File a CCA declaration with SDG&E[m]
4. Develop a detailed implementation plan
5. Make final determination by CCA stakeholders on whether to proceed with the CCA and approve CCA implementation through a City ordinance
6. File the Implementation Plan with CPUC
7. Participate in Open Season[n] by filing a Binding Notice of Intent (BNI) with SDG&E to vintage the Cost Responsibility Surcharge (CRS)[o] impact on CCA customers
8. Complete and confirm a Participant Information Form (PIF) with SDG&E
9. Complete and confirm an Electronic Funds Transfer Agreement with SDG&E
10. Develop and execute a CCA Service Agreement with SDG&E
11. Submit a DUNS number and complete SDG&E credit forms
12. Develop the Electronic Data Interchange (EDI) Trading Partner Profiles and execute an EDI Trading Partner Agreement with SDG&E[p]
13. Conduct and successfully complete EDI & compliance testing with SDG&E[q]
14. Set up billing procedures for customers and with SDG&E
15. Activate a customer service center to process customer inquiries and opt-out requests as well as handling service requests
16. Set up a voice response unit with SDG&E to facilitate opt-out notifications and customer inquiries
17. Provide mass enrollment information to SDG&E
18. Conduct a waiting period
19. Conduct pre-enrollment customer notifications of automatic enrollment, opt-out opportunity and mechanism, and terms and conditions of service

[m] SCE Example CCA Declaration: https://www.sce.com/wps/wcm/connect/0ca1b19b-a7f9-423a-b86c-68e4b2e970c5/081015_CCADeclaration_Form14770.pdf?MOD=AJPERES
[n] Rule 27.2 Community Choice Aggregation Open Season: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE_27_2.pdf
[o] SDG&E Schedule CCA-CRS, Community Choice Aggregation Cost Responsibility Surcharge: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CCA-CRS.pdf
[p] SDG&E Trading Partner Agreement UDC Billing: http://www.sdge.com/documents/trading-partner-agreement-udc-billing
[q] SDG&E Electronic Data Interchange Information: http://www.sdge.com/customer-choice/esp-information/electronic-data-interchange-information

CCA Implementation Steps
20. Perform mass enrollment in phases; each mass enrollment conducted once per enrollment phase
21. Conduct post-enrollment customer notifications of automatic enrollment, opt-out opportunity and mechanism, and terms and conditions of service; each post-enrollment notification conducted once per enrollment phase
22. Pay SDG&E service fees and non-energy costs

One of the first steps to becoming a CCA is the development and filing of a CCA Implementation Plan with the CPUC. PUC Section 366.2(c)[r] describes the requirements for a CCA Implementation Plan and is provided here, in part, for reference:

> *"…(3) A community choice aggregator establishing electrical load aggregation pursuant to this section shall develop an implementation plan detailing the process and consequences of aggregation. The implementation plan, and any subsequent changes to it, shall be considered and adopted at a duly noticed public hearing. The implementation plan shall contain all of the following:*
>
> > *(A) An organizational structure of the program, its operations, and its funding.*
> >
> > *(B) Ratesetting and other costs to participants.*
> >
> > *(C) Provisions for disclosure and due process in setting rates and allocating costs among participants.*
> >
> > *(D) The methods for entering and terminating agreements with other entities.*
> >
> > *(E) The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures.*
> >
> > *(F) Termination of the program.*
> >
> > *(G) A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.*
>
> *(4) A community choice aggregator establishing electrical load aggregation shall prepare a statement of intent with the implementation plan. Any community choice load aggregation established pursuant to this section shall provide for the following:*
>
> > *(A) Universal access.*
> >
> > *(B) Reliability.*

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

(C) Equitable treatment of all classes of customers.

(D) Any requirements established by state law or by the commission concerning aggregated service, including those rules adopted by the commission pursuant to paragraph (3) of subdivision (b) of Section 8341 for the application of the greenhouse gases emission performance standard to community choice aggregators.

(5) In order to determine the cost-recovery mechanism to be imposed on the community choice aggregator pursuant to subdivisions (d), (e), and (f) that shall be paid by the customers of the community choice aggregator to prevent shifting of costs, the community choice aggregator shall file the implementation plan with the commission, and any other information requested by the commission that the commission determines is necessary to develop the cost-recovery mechanism in subdivisions (d), (e), and (f).

(6) The commission shall notify any electrical corporation serving the customers proposed for aggregation that an implementation plan initiating community choice aggregation has been filed, within 10 days of the filing.

(7) Within 90 days after the community choice aggregator establishing load aggregation files its implementation plan, the commission shall certify that it has received the implementation plan, including any additional information necessary to determine a cost-recovery mechanism. After certification of receipt of the implementation plan and any additional information requested, the commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the community choice aggregator to prevent a shifting of costs…."

The CPUC cannot approve or deny the CCA Implementation Plan but will certify that it complies with PUC Section 366.2(c)(3) requirements. The California Energy Commission (CEC) Public Interest Energy Research (PIER) Program Community Choice Aggregation Pilot Project Appendix G Guidebook Section 3.0 Developing a Community Choice Aggregation Implementation Plan[s] provides guidance for developing a CCA Implementation Plan. Additionally, other CCA Implementation Plans are publicly available for reference:

- Lancaster Choice Energy[t]
- Marin Clean Energy[u]
- Sonoma Clean Power[v]

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[s] Reference California Energy Commission (CEC) Public Interest Energy Research (PIER) Program Community Choice Aggregation Pilot Project Appendix G Guidebook Section 3.0 Developing a Community Choice Aggregation Implementation Plan: http://www.energy.ca.gov/2009publications/CEC-500-2009-003/CEC-500-2009-003.PDF

[t] City of Lancaster CCA Implementation Plan: http://www.cityoflancasterca.org/home/showdocument?id=24349

[u] https://www.mcecleanenergy.org/wp-content/uploads/2016/06/Implementation_Plan_w-Resolution__JPA_10.4.12-Richmond-Revised_1.22.13.pdf

[v] https://sonomacleanpower.org/wp-content/uploads/2015/01/2015-SCP-Implementation-Plan.pdf

- County of Los Angeles Community Choice Energy Business Plan[w]
- Inland Choice Power Community Choice Aggregation Business Plan[x]
- San Jose Clean Energy Community Choice Aggregation Business Plan[y]

CUSTOMER NOTIFICATIONS, OPT-OUT, AND ENROLLMENT

PUC Section 366.2(c)(3) contains several requirements regarding CCA customer notifications, enrollment, and the right to opt-out of CCA service:

- Under community choice aggregation, customer participation may not require a positive written declaration, but each customer shall be informed of his or her right to opt-out of the community choice aggregation program.
- Following adoption of aggregation through the ordinance the program shall allow any retail customer to opt-out and to continue to be served as a bundled service customer by the existing electrical corporation, or its successor in interest.
- Once enrolled in the aggregated entity, any ratepayer that chooses to opt-out within 60 days or two billing cycles of the date of enrollment may do so without penalty and shall be entitled to receive default service
- The community choice aggregator shall fully inform participating customers at least twice within two calendar months, or 60 days, in advance of the date of commencing automatic enrollment. Notifications may occur concurrently with billing cycles. Following enrollment, the aggregated entity shall fully inform participating customers for not less than two consecutive billing cycles. Notification may include, but is not limited to, direct mailings to customers, or inserts in water, sewer, or other utility bills. Any notification shall inform customers of both of the following:
    - That they are to be automatically enrolled and that the customer has the right to opt-out of the community choice aggregator without penalty.
    - The terms and conditions of the services offered.
- The community choice aggregator may request the commission to approve and order the electrical corporation to provide the notification required…in the electrical corporation's normally scheduled monthly billing process
    - the electrical corporation shall be entitled to recover from the community choice aggregator all reasonable incremental costs it incurs related to the notification or notifications.
- Each notification shall also include a mechanism by which a ratepayer may opt-out of community choice aggregated service.
- If an existing customer moves the location of his or her electric service within the jurisdiction of the community choice aggregator, the customer shall retain the same subscriber status as prior to the move, unless the customer affirmatively changes his or her subscriber status.

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[w] http://file.lacounty.gov/green/cms1_247381.pdf
[x] https://www.cvag.org/library/pdf_files/enviro/CCA_CVAG_WRCOG_SBCOG_Final_Feasibility_Study%20_12_08_16.pdf
[y] http://www.sanjoseca.gov/DocumentCenter/View/65896

PHASED-IN IMPLEMENTATION OPTION

SDG&E Rule 27[z] details the CCA Specialized Service Request needed to utilize a phased-in approach. The associated SDG&E fees are detailed in SDG&E Schedule CCA[aa] including the Mass Enrollment fee per event of $3,600 and an additional $2,160 per phase.

ELECTRONIC COMMUNICATIONS AND COMPLIANCE TESTING

Communications with IOUs are vital to ensuring successful transactions related to electric meter reading and billing. IOUs utilize the EDI[bb] standard to facilitate the electronic communications and data exchange with CCAs. As part of the process of working with SDG&E to establish the CCA, SDG&E must conduct EDI testing to ensure that operational data exchange is functioning prior to the CCA commencing service.

[z] Rule 27 Community Choice Aggregation Rules: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE27.pdf

[aa] Schedule CCA Transportation of Electric Power for Community Choice Aggregation Customer: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CCA.pdf

[bb] SDG&E Electronic Data Interchange (EDI) Information: http://www.sdge.com/customer-choice/esp-information/electronic-data-interchange-information

APPENDIX D

LOAD FORECAST DEVELOPMENT

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APPENDIX D

LOAD FORECAST DEVELOPMENT

Appendix D provides further discussion and detail of the methodology and assumptions used in the analysis of historical load data and the forecasting of future City CCA program load over the Study period.

HISTORICAL CUSTOMER USAGE

To assess CCA feasibility and plan for CCA operations, the City obtained energy usage information for its potential customers from SDG&E through its CCA information tariff "Schedule CCA-INFO."[1] SDG&E provided aggregate customer and usage data for years 2013 to 2015, including:

1. Proportional share of energy efficiency funds for the City CCA program's proposed service area, as defined in the California Public Utility Commission (CPUC) energy efficiency policy manual;
2. Public Goods Charge customer payments by city code;
3. Most recent 5-year average coincident load factors by rate class;
4. Most recent 5-year average non-coincident load factors by rate class;
5. Mapping of customer rate schedule to rate class;
6. Monthly aggregated participation data already tracked for energy efficiency programs and reported to the CPUC;
7. Distribution loss factors for primary and secondary level of service;
8. Dynamic load profiles;
9. Aggregate annual usage (kWh) by customer class, rate class, city code, rate schedule, zip code, and climate zone;
10. Aggregate monthly usage (kWh) by customer class, rate class, city code, rate schedule, zip code, and climate zone;
11. Number of accounts in each rate schedule within the City CCA program's service area;
12. Direct Access vs. bundled aggregate annual usage by customer class and city code;
13. Direct Access vs. bundled monthly usage by rate class;
14. Non-residential customer specific information consisting of account name, account number, service address, mailing address, and e-mail address for all accounts, within the City CCA program's service area; and
15. Customer specific information: account number, meter number, monthly kWh usage, time-of-use (TOU) usage consumption and maximum monthly demand (where applicable), billing days, and rate schedule, for all accounts within the CCA's service area.[2]

The data provided by SDG&E was reviewed and analyzed and forms the basis for the load forecast used within this Study. This load forecast provides the foundation for the CCA feasibility analysis.

[1] SDG&E Schedule CCA-INFO: Information Release to Community Choice Aggregators http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CCA-INFO.pdf

[2] SDG&E declined to provide the number of DA customers and load by customer class; therefore, the data presented pertaining to DA customers could only be analyzed on an annual energy basis.

The analysis of SDG&E-provided load data focused on bundled customers with the assumption that Direct Access customers would continue with their current Electric Service Provider (ESP) and either opt-out of the CCA or be excluded from CCA enrollment.

For this Study, the total load within the City CCA program's service area was analyzed to determine the load profile for a 24-hour period for each month. SDG&E supplied load profiles[3] corresponding to the date range of the CCA-INFO data. Hourly load profiles provide the hourly customer usage by rate class based on the monthly usage for that rate class. The rate class categories for this Study are summarized in Table D-1.

Table D-1: Customer Categories

Customer Category	Electricity Demand (kW/day)
Large Commercial/Industrial	> 20kW
Small Commercial/Industrial	<= 20kW
Outdoor Lighting	N/A
Large Agricultural	> 20kW
Small Agricultural	<= 20kW
Residential	N/A
Residential Outdoor Lighting	N/A

Figures D-1 and D-2 illustrate the average demand by hour, in kW (and thus the average energy usage by hour, in kWh) for each of the aggregated rate classes by month for both weekdays and weekends/holidays, respectively. Because of the different demand characteristics associated with weekdays and weekends/holidays, these data results are analyzed separately. This data does not include the Direct Access customers and represents the entire pool of bundled customers—those participating in the CCA and those opting out of the CCA.

[3] SDG&E Customer Load Profiles: http://www.sdge.com/customer-choice/customer-load-profiles/customer-load-profiles

Figure D-1: Bundled Customer Average Hourly Weekday Demand by Month and Rate Class

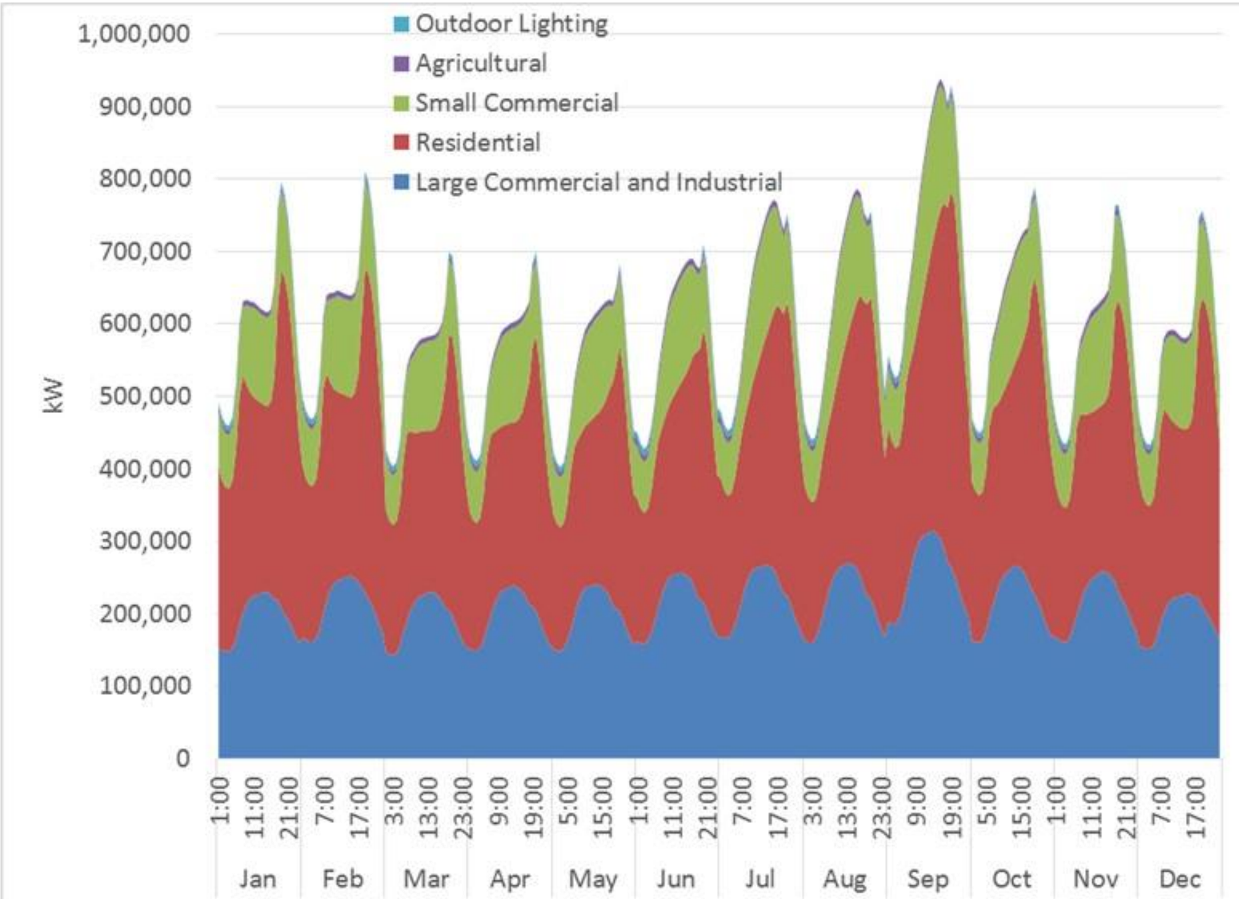
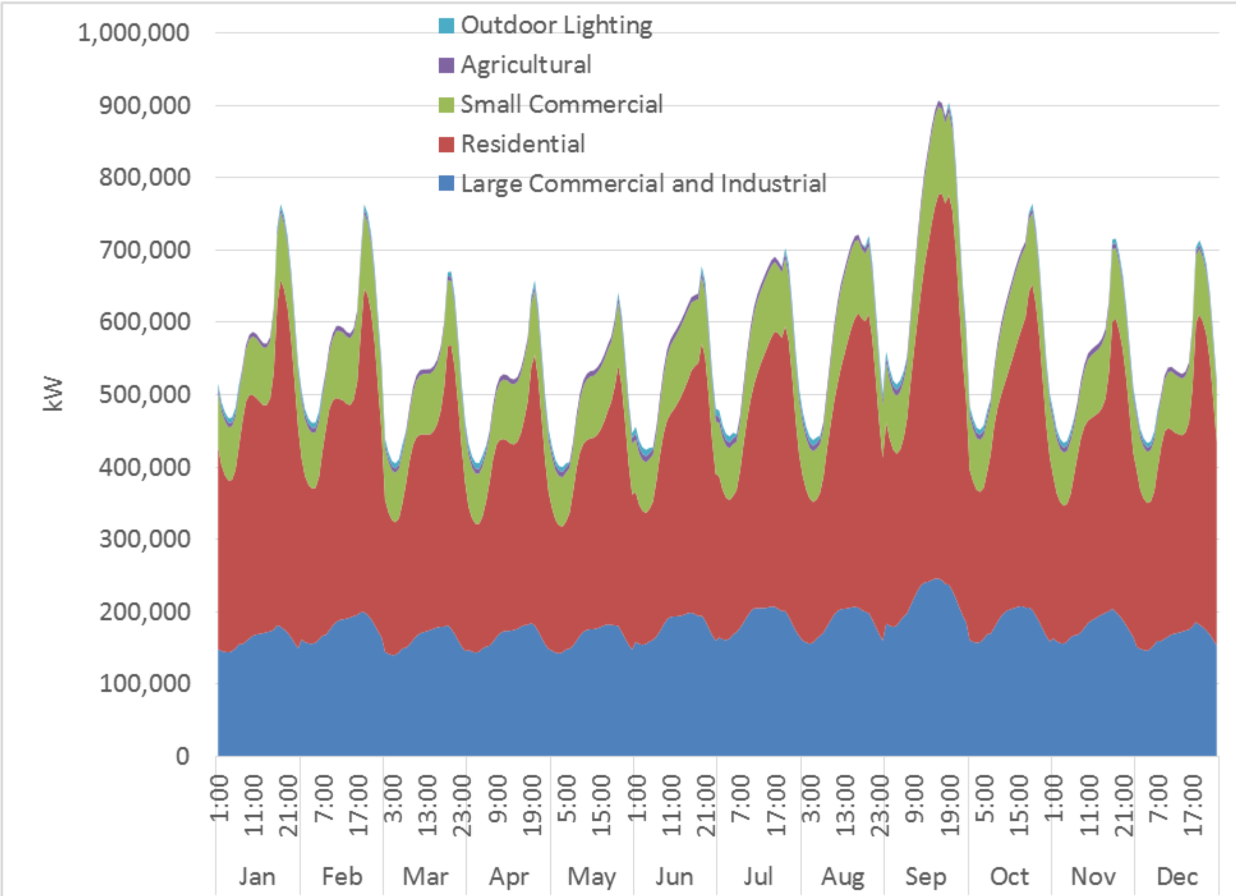


Figure D-2: Bundled Customer Average Hourly Weekend/Holiday Demand by Month and Rate Class



The evaluation of historic SDG&E load data provided a baseline for forecasting future consumption. To develop a forecast of future usage, the Monte Carlo simulation model (MCSM) was used to statistically analyze the range of energy usage as well as power supply costs (power supply cost forecasting methodology is discussed in further detail in Appendix E). Using the historic baseline data, the MCSM analyzed the statistical range of possible outcomes and developed confidence intervals for the expected range of energy usage and demand for each hour of each month.

The historical maximum peak demand and minimum demand fall outside of the 95% confidence interval range.

Analysis of the historical average demand and standard deviation for every given hour of every given day of every given month (with differentiation between weekdays and weekends), was used to develop a 95% probability or confidence that the demand will be within "confidence interval" range above or below the average. This specified range (low end to high end) is the confidence interval, and it is expressed in percentages. Put another way, this equates to an expectation, with 95% confidence, that demand within any given hour will be between the low end of the range and the high end of the range, based on historical sample data.

Figures D-3 and D-4 combine the individual rate classes together to illustrate the maximum, minimum, and average demand for each hour of each month for the bundled customers in the City CCA program's service area, while once again separating weekdays (Figure D-3) from weekends/holidays (Figure D-4). In addition to maximum, minimum and average demand, these Figures also illustrate the 95% confidence interval (CI) around the average derived from the Monte Carlo simulation (+95% CI and -95% CI).

The upper band 95% CI represents a 95% statistical probability that the demand for any given hour will be equal to or less than the upper band 95% CI. Comparison of the 95% CI range to the maximum and minimum demand shows that the maximum demand peaks and minimum demand lows fall outside of the 95% confidence interval range. The statistically-based load profile generated by the MCSM represents the range of the likeliest outcomes and quantifies the chance of actual demand falling outside of the predicted range. These data indicate that, for both weekdays and weekend/holiday time periods, significant demand variability exists from May through October, with less variability during winter and early spring.

Figure D-3: Bundled Customer Weekday Minimum, Average and Maximum Estimated Demand

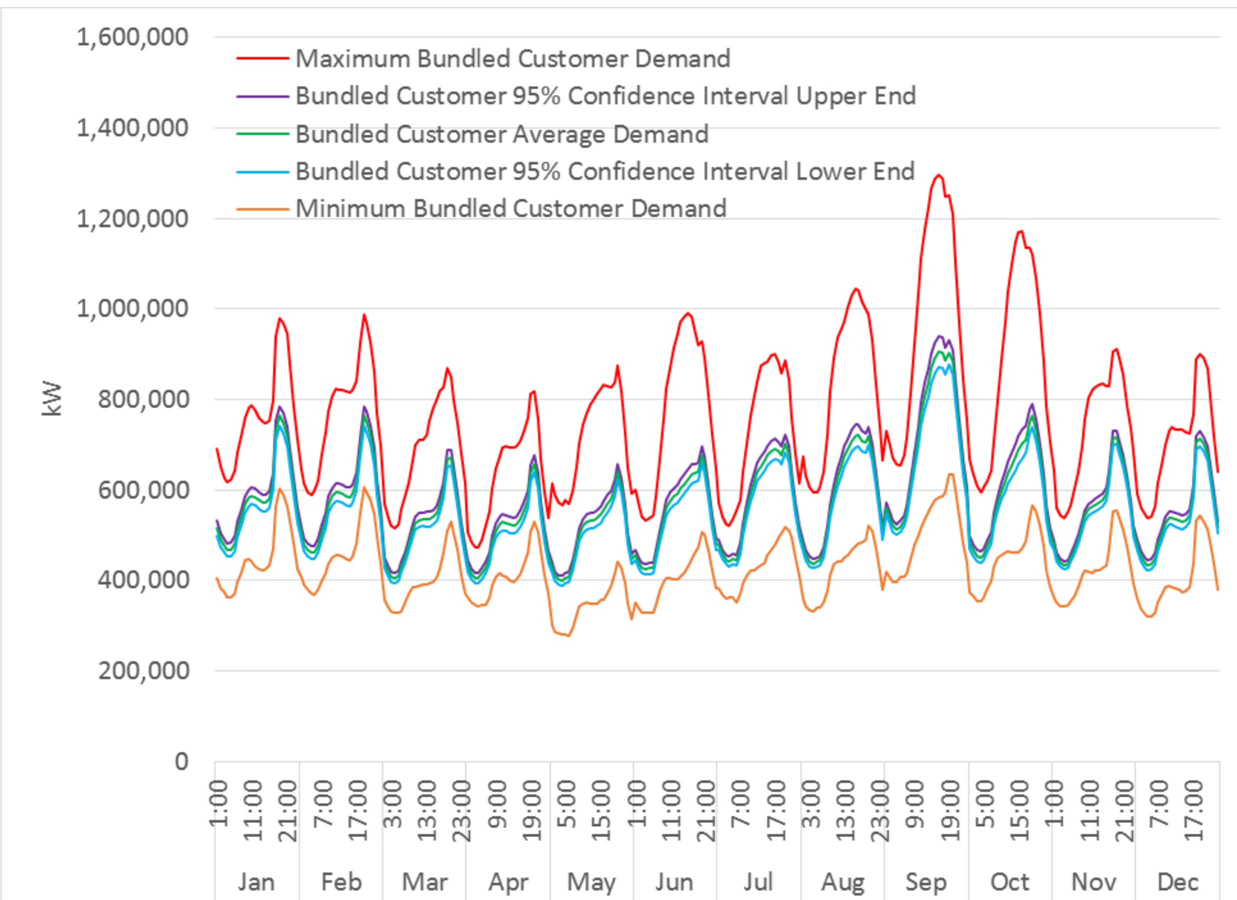
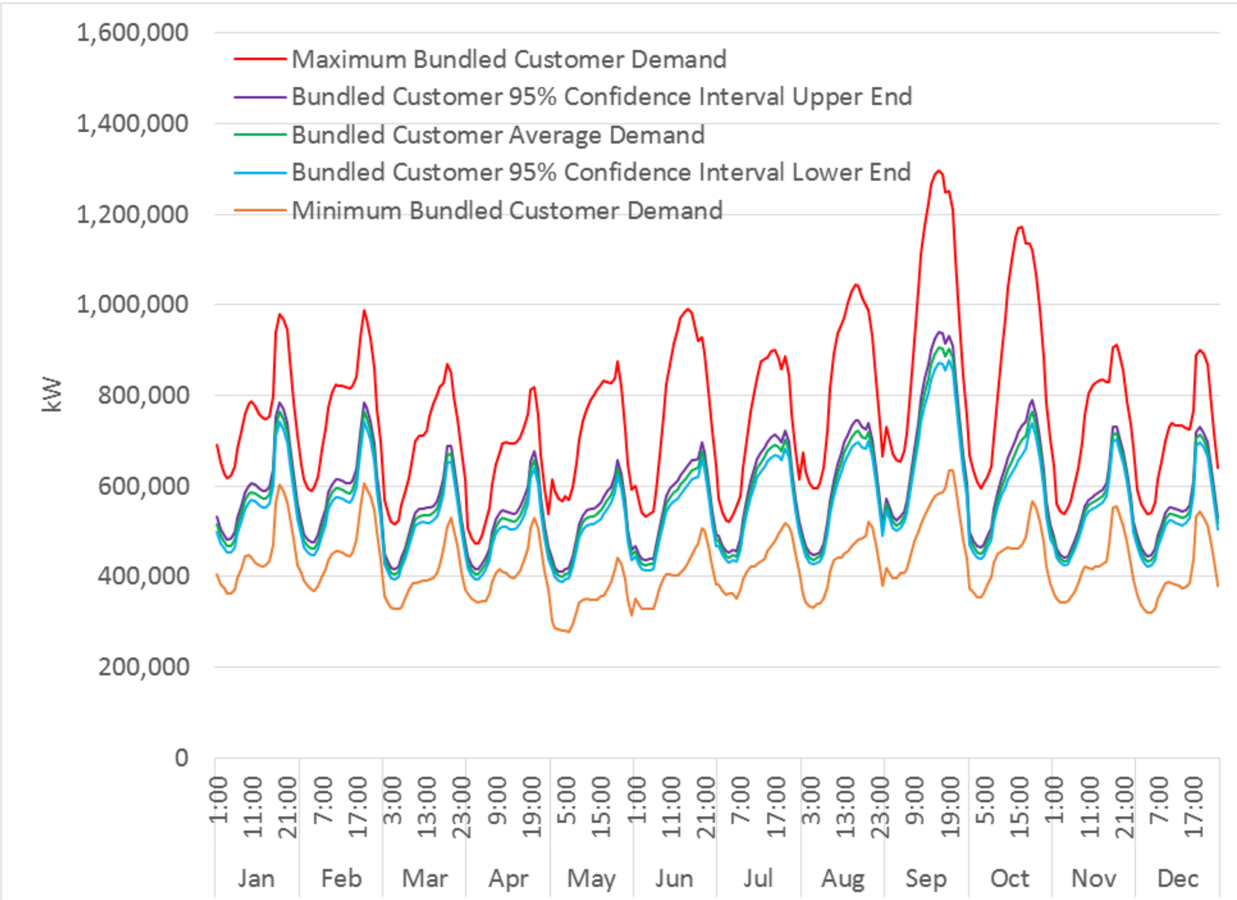


Figure D-4: Bundled Customer Weekend/Holiday Maximum, Average and Minimum Estimated Demand



Multiple factors will likely influence changes in load profile shapes and predictability, including:

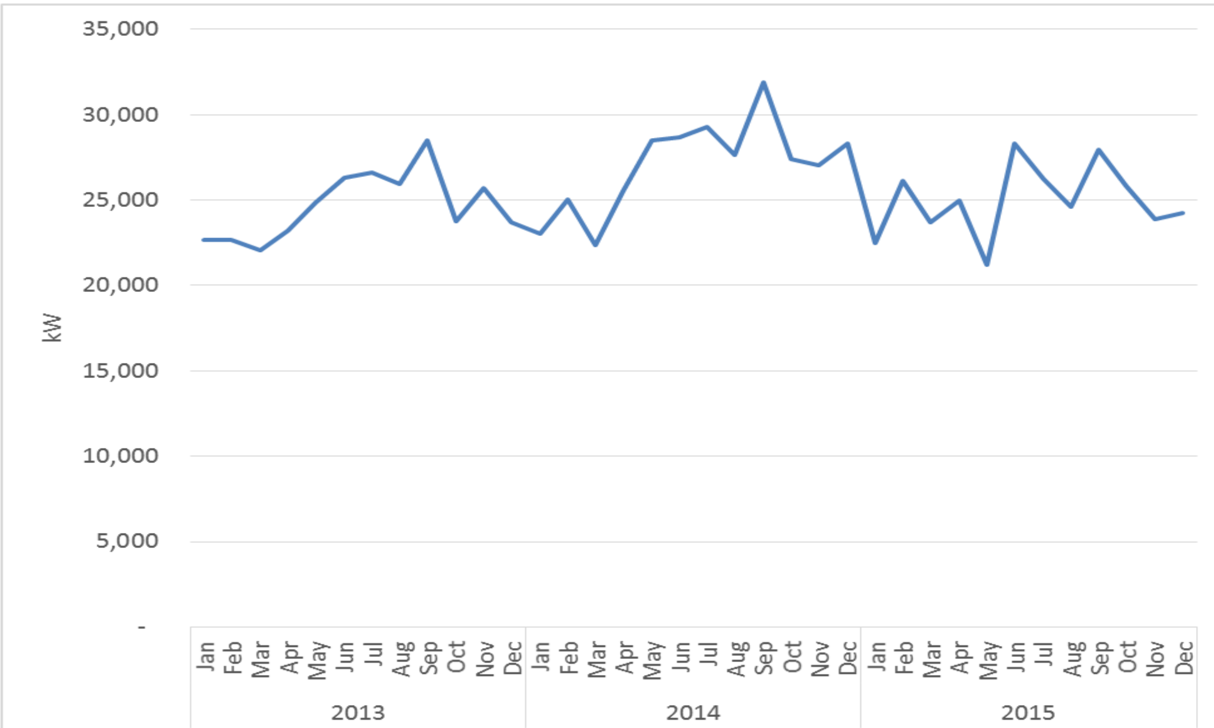
- Customer-owned solar photovoltaic (PV) distributed generation installations have the effect of lowering overall demand and increasing the intermittency and variability of demand served by the LSE as clouds and other factors influence the output of the solar panels. As more customers adopt rooftop solar PV, changes in profile shapes may be more dramatic.
- Plug-in electric vehicles (PEVs) can draw as much electricity as the rest of the home and have the effect of dramatically increasing customer electric demand. Utilities are developing specific PEV rate structures to incentivize customers to charge their vehicles at certain times of day. As more customers adopt PEVs and LSEs implement PEV rate structures, profile shapes will be impacted.

SAN DIEGO MUNICIPAL ACCOUNT USAGE

The City had originally considered multiple phasing-in options of various customer classes, including a phasing in of City of San Diego municipal accounts (those paid by the City). Using the historical SDG&E load data, an analysis was performed to determine the electricity demand for municipal accounts.

Ultimately, phasing options were determined that did not consider the phasing in of municipal accounts. As such, the information contained herein is largely for reference purposes only. The historical maximum monthly electricity demand for these municipal accounts is summarized in Figure D-5.

Figure D-5: Historical Monthly Maximum Peak Demand for City of San Diego Municipal Accounts



Figures D-6 and D-7 illustrate the average demand by hour, in kW (and average energy usage by hour, in kWh) for each of the aggregated rate classes by month for weekdays and weekends/holidays, respectively for the City of San Diego municipal accounts.

Figure D-6: Average Hourly Weekday Demand for City of San Diego Municipal Accounts by Month and Rate Class

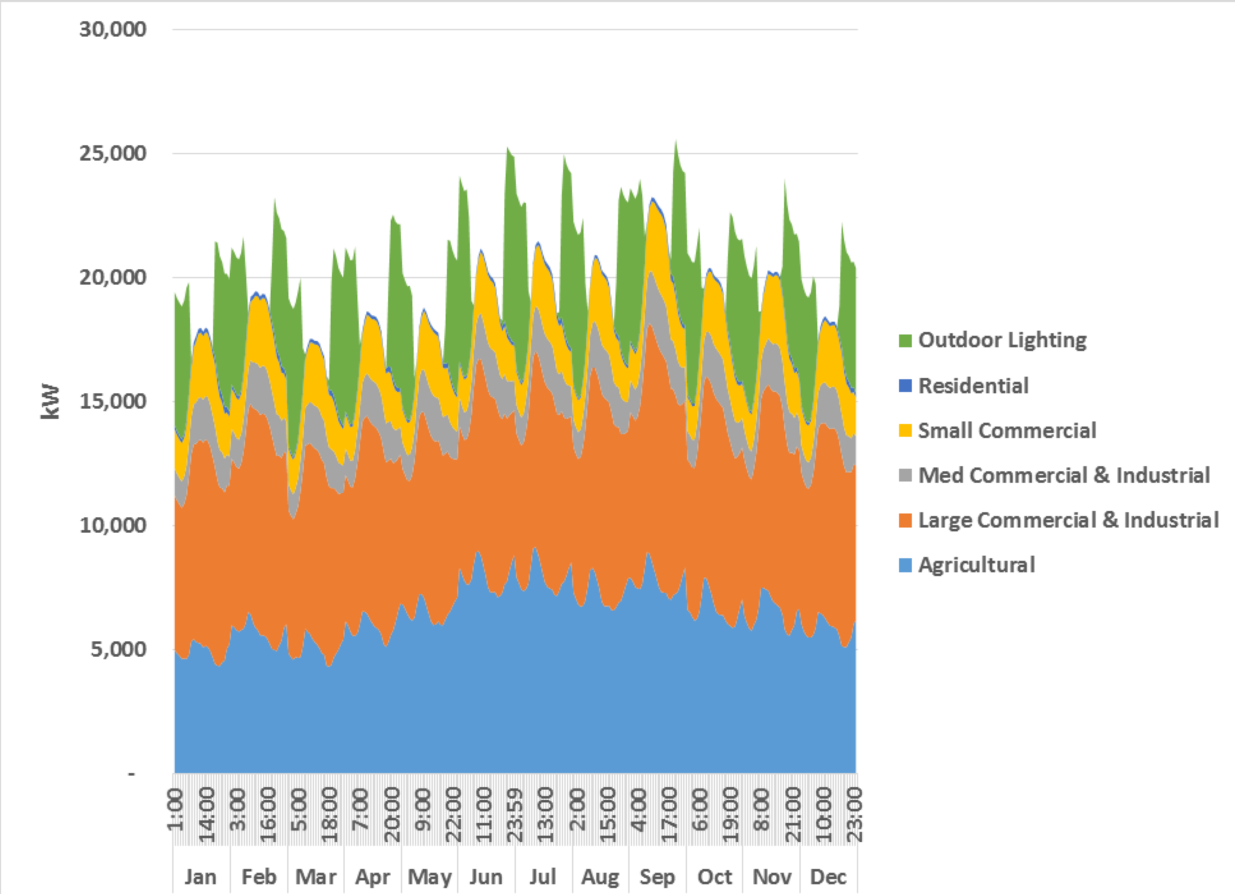
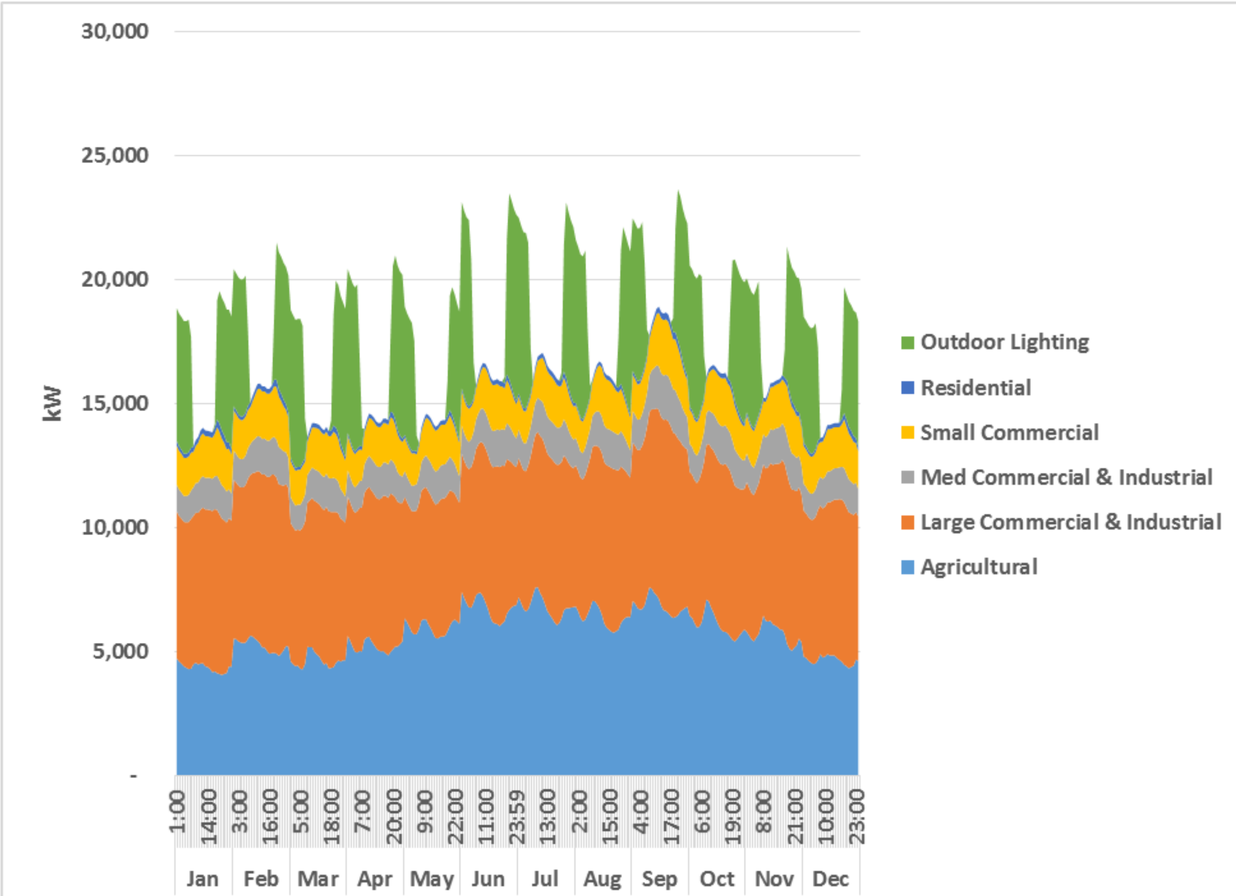


Figure D-7: Average Hourly Weekend/Holiday Demand for City of San Diego Municipal Accounts by Month and Rate Class



TEMPERATURE AND ENERGY USAGE CORRELATION

Temperature and humidity are large drivers of energy usage in California because a significant source of usage is air conditioning. Hot weather increases air conditioning usage and humidity levels impact the efficiency, and thus the energy use, of air conditioning systems. As a result, power procurement planners must look closely at weather forecasts to refine energy and capacity forecasts. Figures D-8 and D-9 illustrate the electric consumption by end-use for SDG&E's Commercial customers for the Coastal and Inland Regions, respectively. Figure D-10 shows this same consumption data for all Residential customers.

According to the U.S. Department of Energy, approximately 6% of electricity produced in the U.S. is used for air conditioning.[4] San Diego's relatively mild climate attributes to its proportional use of power for air conditioning. A very small portion of usage goes to heating. And although cooling load is significant in the area, in some parts of the country, Commercial and Residential customer classes might see a larger portion of their usage attributable to cooling and air conditioning load.

[4] U.S. Department of Energy website: https://energy.gov/energysaver/air-conditioning

Figure D-8: SDG&E Commercial Electricity Usage, Coastal Region[5]

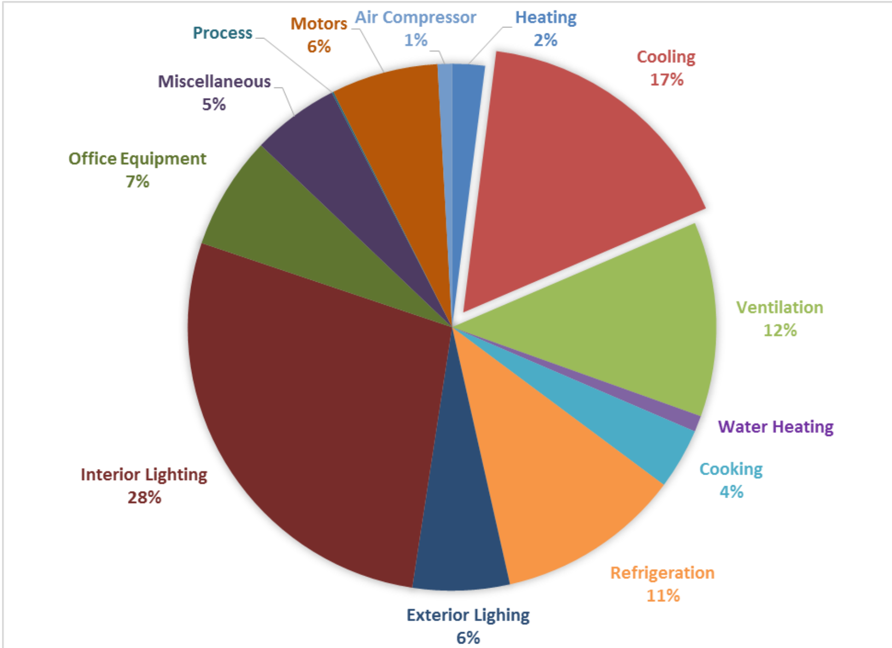
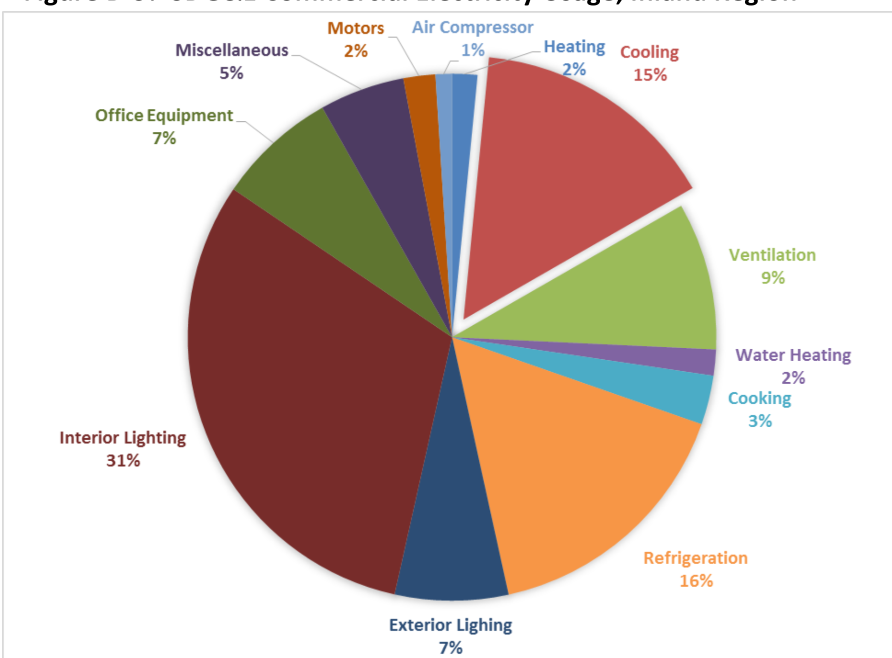
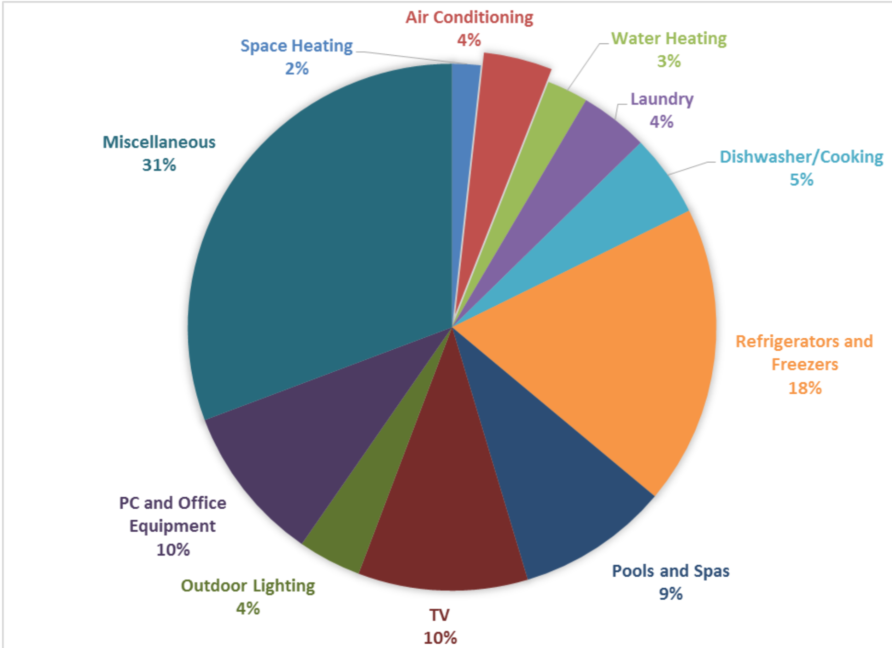


Figure D-9: SDG&E Commercial Electricity Usage, Inland Region[6]



[5] Itron California Commercial End Use Survey, 2006: http://capabilities.itron.com/CeusWeb/ChartsSF/Default2.aspx
[6] Ibid.

Figure D-10: SDG&E Residential Class Electricity Usage, All Regions[7]



For the purposes of this Study, the MCSM assumes a similar range and frequency of temperatures as was encountered during years 2013-2015. Therefore, the temperature variation is embedded in the historical peak demand and usage data received by SDG&E.

Statistically, SDG&E customer usage can be correlated to temperature as illustrated in Table D-2. The results indicate that, at temperatures over 70° F, temperature and electricity usage are correlated. The analysis included the effect of humidity on energy demand, using what is known as "wet bulb" analysis that incorporates both outdoor air temperature and dew point depression.[8] The results indicate a low correlation between energy use and humidity, likely due to San Diego's relatively dry climate.

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[7] California Energy Commission - 2009 California Residential Appliance Saturation Study http://www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-ES.PDF

[8] Shortcut to calculating wet bulb temperature: http://theweatherprediction.com/habyhints/170/

Table D-2: Temperature to Electricity Usage Correlation[9]

	Weekday		Weekend / Holiday	
Month	Dry Bulb Correlation	Wet Bulb Correlation	Dry Bulb Correlation	Wet Bulb Correlation
1	0.33	0.14	0.11	0.09
2	0.31	0.11	0.26	0.25
3	0.38	0.08	0.40	0.12
4	0.51	0.12	0.36	0.40
5	0.61	0.08	0.61	0.63
6	0.64	0.63	0.59	0.59
7	0.66	0.63	0.54	0.50
8	0.81	0.80	0.76	0.75
9	0.83	0.82	0.73	0.73
10	0.56	0.58	0.76	0.33
11	0.62	0.19	0.49	0.16
12	0.38	0.14	0.32	0.10
Temp	**Dry Bulb Correlation**	**Wet Bulb Correlation**	**Dry Bulb Correlation**	**Wet Bulb Correlation**
<70° Fahrenheit	0.20	0.28	0.13	0.30
>=70° Fahrenheit	0.63	0.13	0.61	0.17

Figure D-11 illustrates weekday usage variability relative to temperature and Figure D-12 illustrates weekend/holiday electricity usage variability relative to temperature for bundled customers. In both Figures, usage rises more sharply at temperatures above 70° F.

[9] National Oceanic and Atmospheric Administration (http://gis.ncdc.noaa.gov/map/viewer/#app=cdo) and wet bulb temperature derivation (http://theweatherprediction.com/habyhints/170/)

Figure D-11: Weekday Bundled Electricity Usage Variability for Temperature

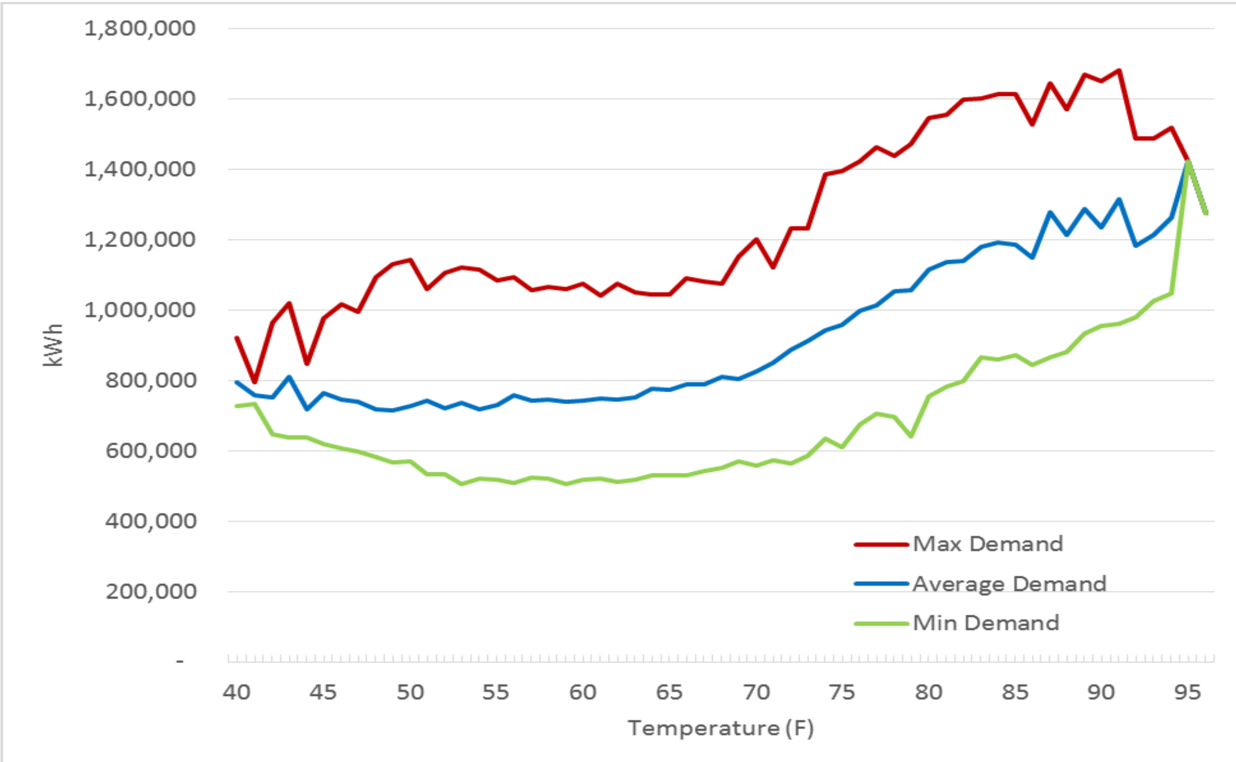
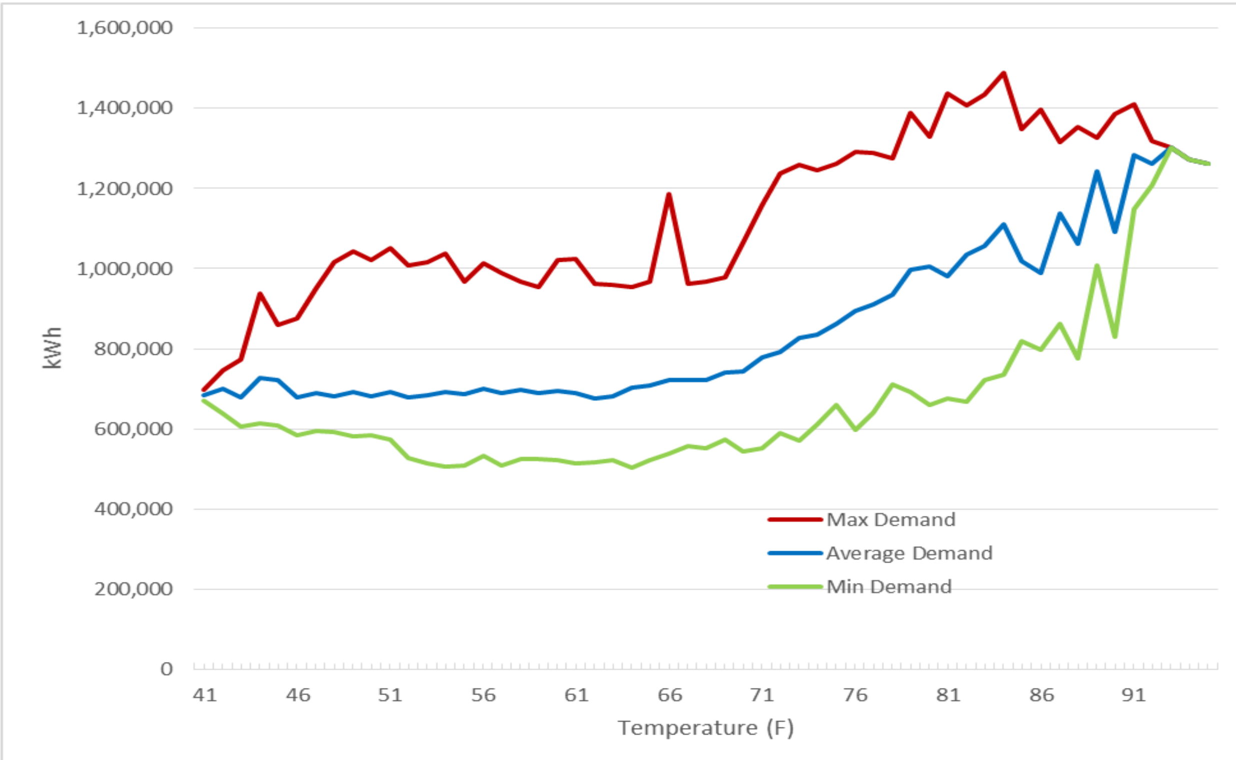


Figure D-12: Weekend / Holiday Bundled Electricity Usage Variability for Temperature



This discussion on temperature and energy usage correlation is intended to illustrate one of the considerations for forecasting near-term CCA load forecasts. Medium and short term PPAs can be purchased if the weather forecast is predicting hotter or more humid weather than expected. Additionally, if the weather forecast is for cooler or less humid than expected, excess energy already procured by the CCA can be sold. Otherwise, excess energy will need to be sold through CAISO markets and shortfall energy will need to be purchased through CAISO markets.

Because the results of this demand and temperature analysis showed relatively low correlation, this Study did not consider the effect of possibly rising energy needs associated with a potentially warmer climate.

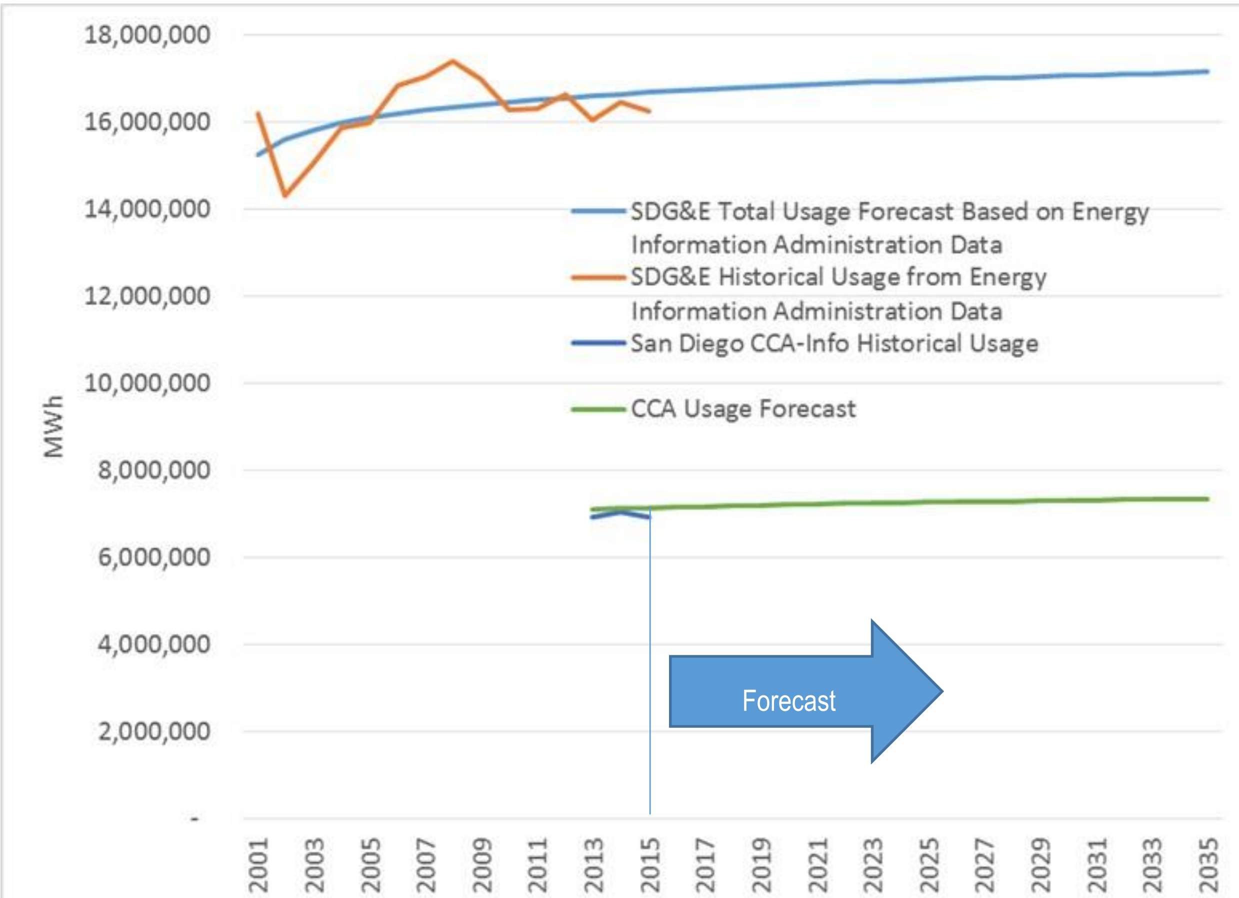
CUSTOMER USAGE FORECAST

The Study relied on the annual electricity usage for SDG&E's entire service territory from 2001 to 2015, as reported in the U.S. Department of Energy's Energy Information Administration's Form EIA-826,[10] to develop a curve fit forecast of electric energy consumption through 2035. Using the historical SDG&E-provided data for 2013-2015 and the EIA-826 data, the load growth shape (slope of the curve) was extrapolated to the subset of bundled customer energy consumption within the City of San Diego as shown in Figure D-13. The green curve labeled "CCA Usage Forecast" is the baseline forecast for electric

[10] DOE Energy Information Agency, Form EIA-826Monthly SDG&E Delivery & Sales 2010-2015: http://www.eia.gov/electricity/data/eia826/

energy consumption by bundled customers within the City CCA program's service area for the 2020-2035 time period. This includes future bundled-customer consumption served by either SDG&E or the City CCA program as well as consumption served by future installations of customer-owned distributed generation, namely solar PV. The removal of consumption served by customer-owned distributed generation from the forecast of load to be served by the CCA is discussed in further detail in the next report segment titled "Adjusted Forecast with Distributed Generation."

Figure D-13: Historical and Forecasted Usage for SDG&E and the City



Four load patterns are visible in the SDG&E historical usage shown in Figure D-13:

- first, a marked reduction in annual electricity consumption from 2001 to 2002;
- second, an increase in consumption over pre-2001 levels from 2005 to 2008;
- a decrease in load from 2008 to 2010; and
- a dip and recovery between 2011 and 2014.

The consumption reductions are in part attributable economic conditions with the 2001-2002 dot-com bubble and 2008-2010 the housing bubble and subsequent "great recession." The relatively flat load growth from 2010-2012 can be attributed to the slow economic recovery from the "great recession." Additionally, the exponential growth in customer-owned solar PV distributed generation also reduced the electricity usage served by SDG&E. Other factors contributing to the relatively flat load growth from 2010-2015 include energy efficiency inroads for existing housing stock, appliances, and light bulbs—progressing from incandescent to compact fluorescent and now to light emitting diode (LED) bulbs.

In addition to these factors contributing to lower electricity consumption, there are also factors that contribute to increasing electricity demand including:

- Plug-in Electric Vehicles
- Proliferation of consumer electronics including smart phones and tablet computers–although there is now emphasis on better energy efficiency for these devices
- Economic growth

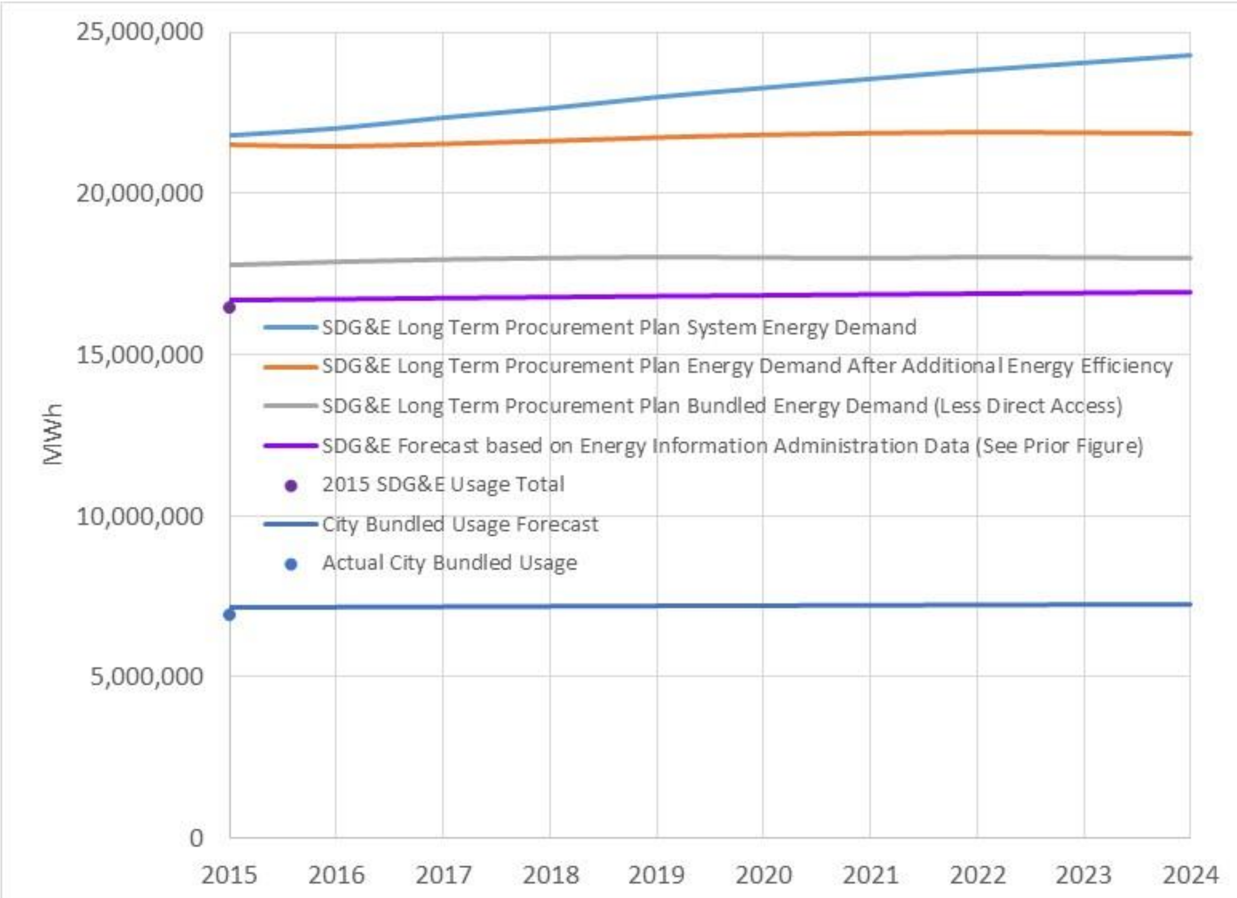
To check the reasonableness of CCA Usage Forecast used within the Study, it was compared it to the SDG&E Long Term Procurement Plan (LTPP)[11], including SDG&E's Draft 2014 LTPP Table A-2 (Energy),[12] as well as the CPUC Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.[13] Figure D-14 compares the SDG&E Draft 2014 LTPP and the CCA Usage Forecast depicted in Figure D-13.

[11] SDG&E Long Term Procurement Plan Proceeding, Docket Number: R.12-03-014, Filing Date: Thursday, March 22, 2012: http://www.sdge.com/regulatory-filing/3520/long-term-procurement-plan-proceeding

[12] SDG&E's Draft 2014 Long-Term Procurement Plan: https://www.sdge.com/sites/default/files/regulatory/PUBLIC-SDGE-Bundled-Plan.pdf

[13] CPUC Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans Rulemaking 13-12-010: https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1312010

Figure D-14: 2014 Draft SDG&E LTPP compared with 2015 Historical Energy Consumption and CCA Forecast



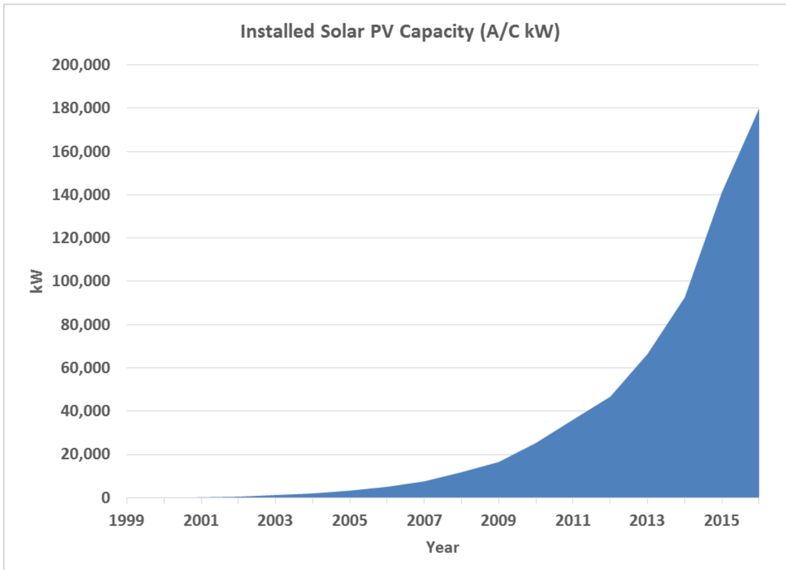
The primary purpose for the comparison in Figure D-14 is to ensure alignment between the slope of the CCA Usage Forecast and the SDG&E LTPP forecast that include additional energy efficiency measures. The desired parallel alignment is evident between the LTPP forecast and the CCA Usage Forecast, thereby validating the reasonableness of the relatively flat load forecast used in the Study.

ADJUSTED FORECAST WITH DISTRIBUTED GENERATION

From this baseline "CCA Usage Forecast," additional reductions in forecasted CCA customer demand due to distributed generation were made. As mentioned earlier in the discussion of factors influencing load profiles, the amount of customer-owned distributed generation will impact customer demand for LSE-provided energy and capacity, both overall and in terms of load shape.

Looking at the historical trend, the California Solar Initiative's currently connected data set[14] shows that within the City of San Diego, there has been nearly exponential growth in customer-owned solar PV installed capacity since 1999. This trend is illustrated in Figure D-15.

Figure D-15: California Solar Initiative Incentivized Customer-Owned Solar PV in the City of San Diego



To understand the impact of customer-owned solar PV distributed generation in San Diego, a generation profile was developed using the National Renewable Energy Laboratory's (NREL's) PVWatts calculator.[15] Figures D-16 and D-17 illustrate the load served by customer-owned solar PV distributed generation, over and above the load currently served by SDG&E for weekdays and weekends/holidays, respectively. The red curve on top of the green curve represents the total level of energy demanded by customers, including that served by solar PV generation.

[14] California Distributed Generation Statistics Currently Interconnected Data Set (Current as of Aug. 30, 2016): http://www.californiadgstats.ca.gov/

[15] National Renewable Energy Laboratory (NREL) PVWatts® Calculator http://pvwatts.nrel.gov/

Figure D-16: Average Weekday City of San Diego Bundled Demand, Served by SDG&E and Served by Customer-Owned PV

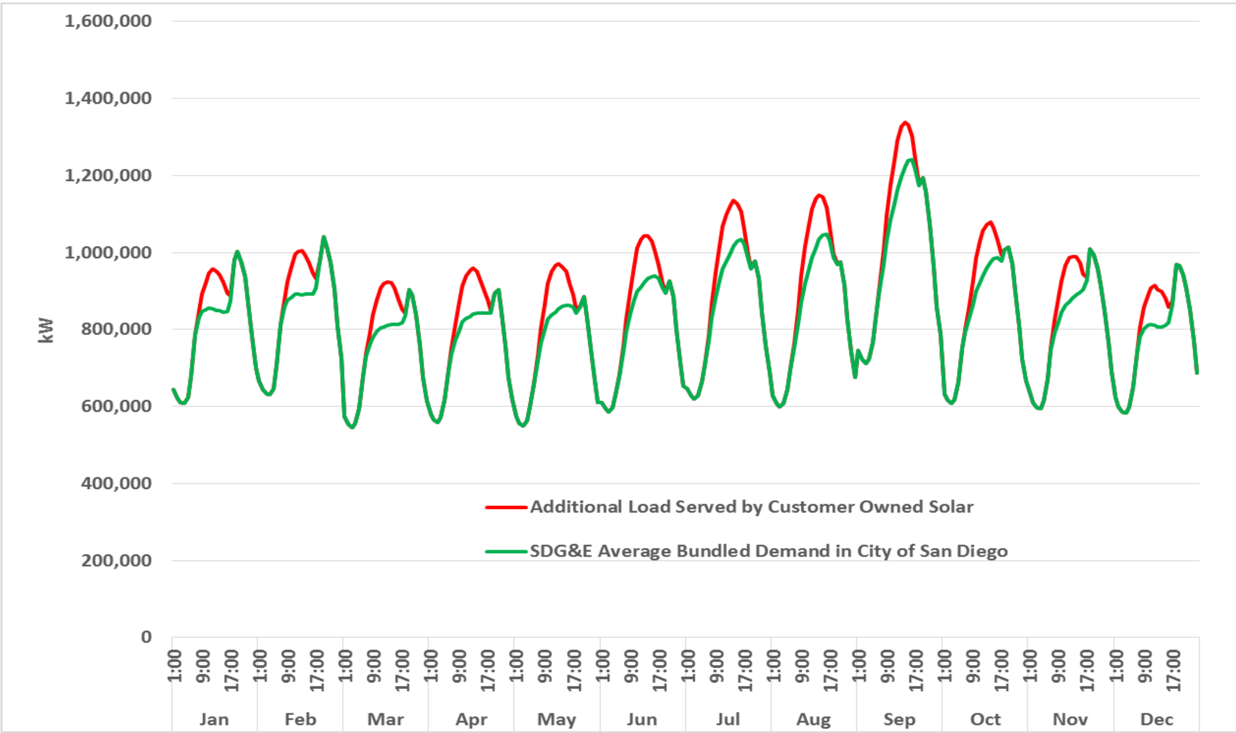
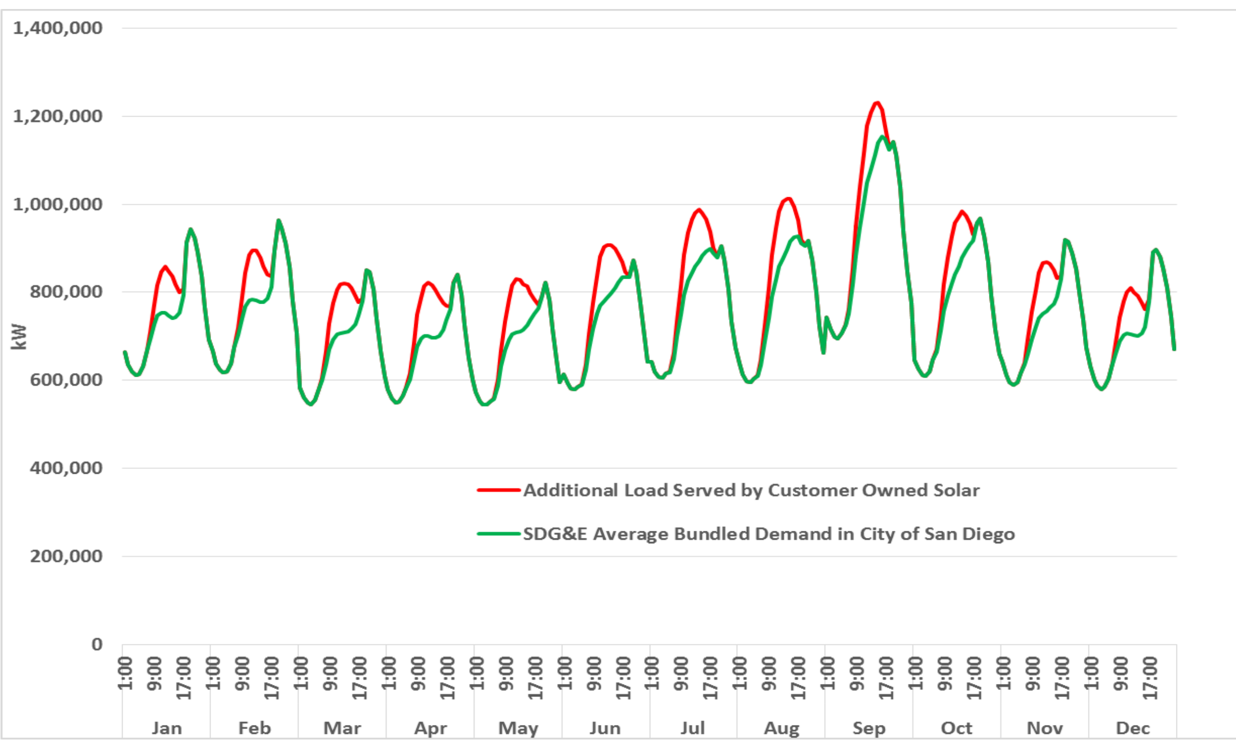


Figure D-17: Average Weekend/Holiday City of San Diego Bundled Demand, Served by SDG&E and Served by Customer-Owned PV



Over the load forecast horizon, expansion of customer-owned solar PV is expected to continue, reducing electric energy demand served by either SDG&E or the CCA. With respect to the CCA load forecast, the question becomes how will customer-owned solar PV impact future loads. To answer this, the historical San Diego-specific solar PV installation data from California Distributed Generation Statistics[16] (formerly California Solar Statistics) was extrapolated into a forecast for 2020-2035 as illustrated in Figure D-18.

Figure D-18: Customer Owned Solar PV Projection through 2035

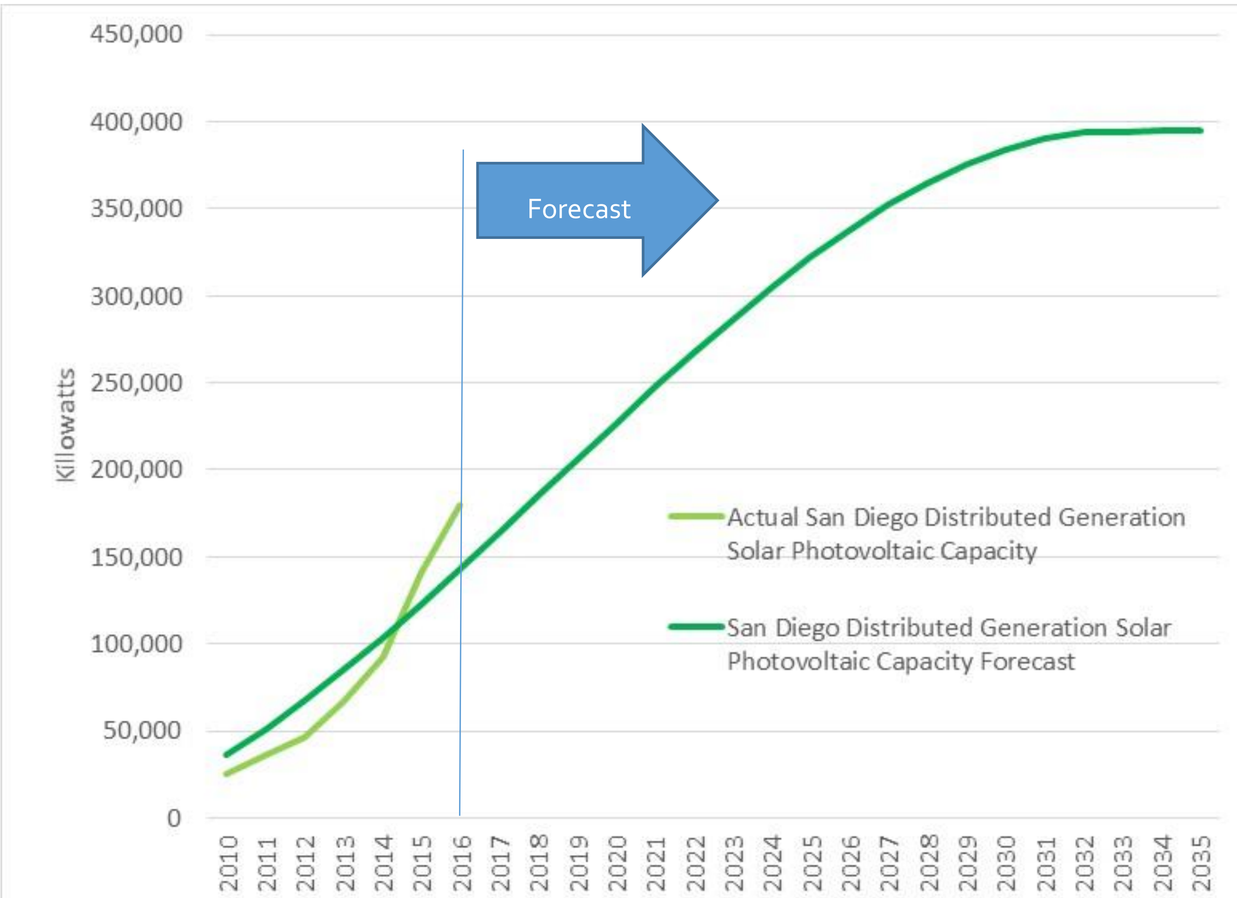


Table D-3 includes the minimum, average, upper bound 95% confidence interval, and maximum load forecasts for 2020-2035. For each forecast, the "Net Simulated Annual MWh" column removes from the "Simulated Annual MWh" column the energy produced by the installations of solar PV distributed generation to estimate the net load that would be served by the LSE (SDG&E or the City CCA program). This net load forecast illustrates that less and less LSE-provided power will be sold over time as solar PV distributed generation continues to proliferate. Under no forecast is a future year's net load projected to be higher than year 2020.

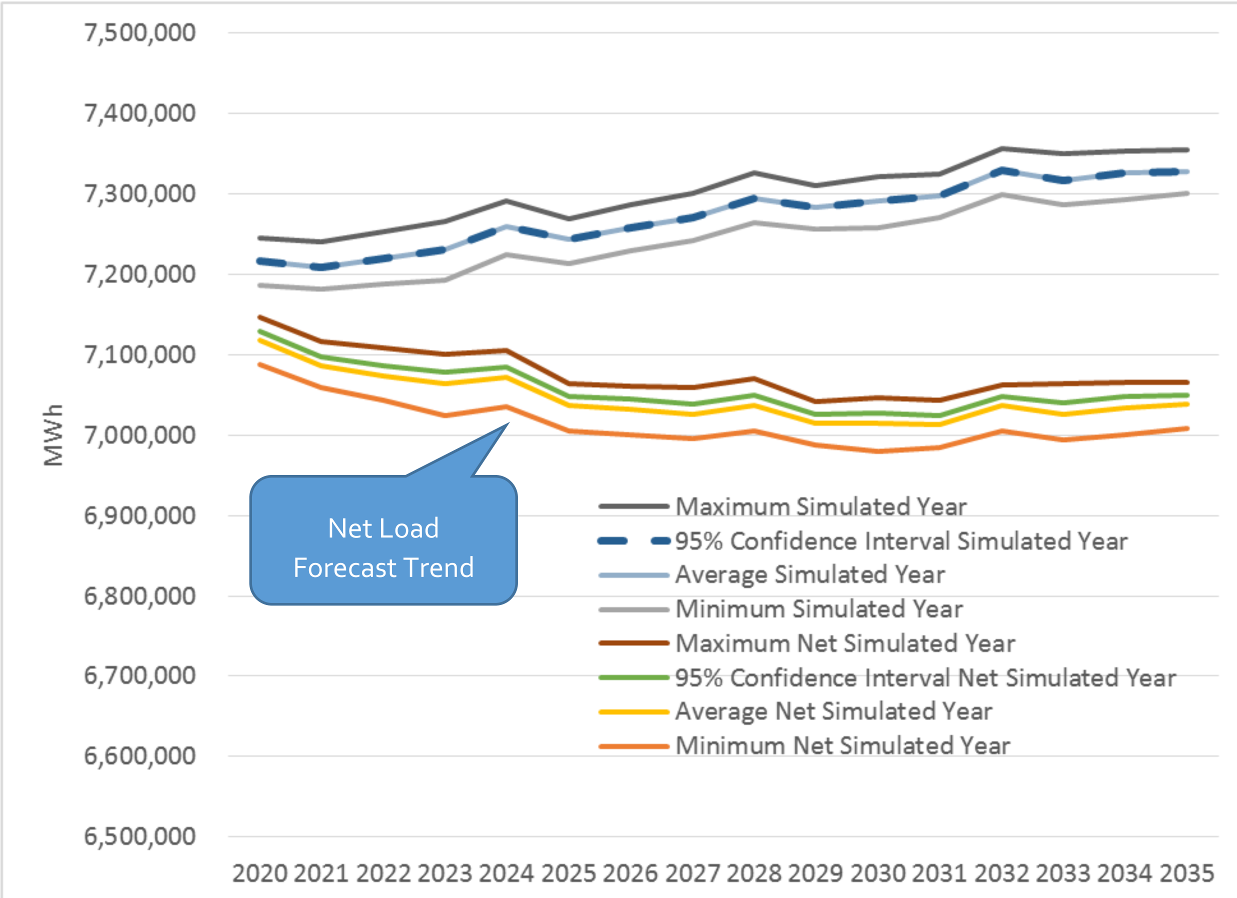
[16] California Distributed Generation Statistics: http://www.californiadgstats.ca.gov/

Table D-3: Distributed Generation Adjusted Customer Usage Forecast

	Minimum		Average		95% CI		Maximum	
Year	Net Simulated Month MWh	Simulated Month MWh	Net Simulated Month MWh	Simulated Month MWh	Net Simulated Month MWh	Simulated Month MWh	Net Simulated Month MWh	Simulated Month MWh
2020	7,087,871	7,187,191	7,117,801	7,216,409	7,129,503	7,216,771	7,147,447	7,245,645
2021	7,059,693	7,182,264	7,086,807	7,209,345	7,098,102	7,209,345	7,117,198	7,240,004
2022	7,043,373	7,188,665	7,074,154	7,219,150	7,086,700	7,219,150	7,108,377	7,253,669
2023	7,025,019	7,193,274	7,063,426	7,230,447	7,077,799	7,230,447	7,100,016	7,265,765
2024	7,035,430	7,224,777	7,071,428	7,259,531	7,084,168	7,259,531	7,104,618	7,291,144
2025	7,005,424	7,212,815	7,036,459	7,242,997	7,048,318	7,242,997	7,063,939	7,269,051
2026	7,000,604	7,228,916	7,032,092	7,258,511	7,044,270	7,258,511	7,060,759	7,286,946
2027	6,995,457	7,242,391	7,026,422	7,270,167	7,038,783	7,270,167	7,059,388	7,300,978
2028	7,005,412	7,264,396	7,037,275	7,294,165	7,050,206	7,294,165	7,070,926	7,325,561
2029	6,988,348	7,256,771	7,015,320	7,283,299	7,026,284	7,283,299	7,042,480	7,310,325
2030	6,979,918	7,257,910	7,014,284	7,291,482	7,026,740	7,291,482	7,046,320	7,321,843
2031	6,983,958	7,271,071	7,013,005	7,298,152	7,024,550	7,298,152	7,043,294	7,325,459
2032	7,005,261	7,298,666	7,036,775	7,328,989	7,048,259	7,328,989	7,062,802	7,355,753
2033	6,993,430	7,286,082	7,026,548	7,317,417	7,040,691	7,317,417	7,063,522	7,350,782
2034	7,000,402	7,293,358	7,034,491	7,325,790	7,047,360	7,325,790	7,065,132	7,353,889
2035	7,008,934	7,300,539	7,038,361	7,328,088	7,050,004	7,328,088	7,066,162	7,354,998

Figure D-19 shows the effect of customer-owned distributed generation on the amount of energy served by an LSE within the City CCA program's service area (either SDG&E or the CCA). The bottom set of four lines represent the Net Load Forecast Trend, compared to the top four lines that represent the forecast without the removal of load served by distributed generation. This Figure illustrates while the overall demand for energy within the City is expected to rise across the forecast period, the effect of distributed generation reduces the amount of energy sold by the LSEs. Note that this trend is affecting all LSEs in California and would not be unique to a potential CCA in San Diego.

Figure D-19: Load Forecast and Net Load Forecast



The following Appendix E discusses how the Net Load Forecast was used to develop power procurement costs, including additional detail regarding Monte Carlo-style hourly simulations of load.

APPENDIX E

POWER COST DEVELOPMENT

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APPENDIX E

POWER COST DEVELOPMENT

Appendix E discusses energy supply considerations as well as additional detail and discussion regarding the methodology and assumptions used to develop the power supply costs for each supply Scenario within the Study.

ENERGY SUPPLY CONSIDERATIONS

As discussed in the main body of this report, a core goal for the City CCA program is to develop an energy supply portfolio with lower greenhouse gas (GHG) emissions and at a faster rate than SDG&E's energy supply portfolio is forecast to offer. In addition, the City CCA program would prioritize the development of local renewable resources with diverse energy options for customers. Most other CCAs have similar goals. For example, Lancaster Clean Energy decided to develop the initial CCA energy portfolio with a renewables component at 35% in their first year in order to exceed the California Public Utility Commission's (CPUC's) 2020 Renewable Portfolio Standard (RPS) goal of 33%. Lancaster Clean Energy's plan is to expand renewable supply resources over time. Because the location of Lancaster is very conducive to local solar and regional wind generation resources, this CCA is well situated to meet its supply needs with local renewable resources.

The energy supply portfolio for a Load Serving Entity (LSE) in California, whether IOU or CCA, is typically comprised of three primary sources:

1. Self-supplied generation from assets the LSE owns (or contractually controls) and operates;
2. Power Purchase Agreement (PPA)-procured generation through bi-lateral contracts with independent power producers;
3. California Independent System Operator (CAISO) day-ahead and real-time market purchases.

LSEs develop multi-year integrated resource plans to evaluate energy resources; and these plans incorporate a host of demand-side and supply-side drivers, including the integration of energy efficiency programs and objectives. A well-executed integrated resource plan results from a tested and rigorous planning process. The primary goal is to assess a full range of resource alternatives under a variety of scenarios to provide reliable service to customers at the lowest possible cost. There may be other important goals at play as well, such as resource diversity, environmental stewardship, and energy independence, among others.

The primary components or tasks involved with integrated resource planning are:

1. Identify and prioritize the planning goals to be achieved and identify any supply-side or demand-side planning constraints;
2. Identify, discuss, and confirm the assumptions used for all aspects of the IRP with technical experts and relevant stakeholders;

3. Model and evaluate—from operational, economic, and financial perspectives—the various supply-side and demand-side options, under a variety of future scenarios, to develop a resource plan that best achieves stated goals and objectives at the least-possible cost;
4. Receive and use diverse stakeholder feedback and communicate the planning process so the process is understood and endorsed;
5. Communicate the results of the plan so that they are understood and endorsed and the plan can move forward.

The resulting integrated resource plan provides guidance and direction to energy supply managers for procurement activities over the planning time horizon. Generally, these integrated resource plans are updated on a regular basis. For most utilities facing changing load patterns, shortfalls or overages of available generation, susceptibility to volatile market prices, or other cost drivers that may be difficult to quantify over a longer-term, these plans are updated every one or two years.

In general, for any electric energy demand to be served, specific power products must be procured. Because electric energy is currently not readily stored at a large scale, electricity production is matched to electric consumption instantaneously. The nature of the electric system is that it is managed to be self-balancing—that is, dispatchable generation resources will move to match load, either increasing or decreasing in real time. The specific power products are designed to keep the system in balance and allocate costs fairly; and they have different characteristics depending on type (such as energy- or capacity-related), specific services (such as ancillary services), and taking into consideration market costs (CASIO uplift charges, for example).

Managing an energy supply portfolio is an exercise in forecasting demand requirements under various scenarios and identifying the types of energy supply portfolio resources needed to most cost-effectively meet the requirements over a specific period. Most LSEs use a risk management approach for energy supply which is designed to seek a combination of fixed and variable cost options while identifying and quantifying the associated risks. Risk is mitigated through diversified supply technologies, sizes, and locations as well as contract terms, lengths, and timing. Managing an energy supply portfolio is an active, daily responsibility. An LSE can manage this activity internally or can outsource this function to a third-party supplier.

Mitigating risk for a supply portfolio is more difficult when the supply comes predominately from a single, specific generation source (such as a or a single plant) or a single type of generation that may be subject at the same time to conditions affecting their output (such as several wind farms located in the same geographic region). In the case of the power supply portfolio options explored in this Study, renewable energy is providing between half and all of the energy supply. While geothermal generation has predictable output like fossil fuel generation, solar and wind generation is intermittent. The forecast accuracy for wind and solar generation is getting better, but when customer-side and supply-side renewable generation output varies from expectations, it often results in both high and low CAISO prices. The high adoption rates for customer-owned solar PV distributed generation as well as large numbers of utility-scale renewable resources increase exposure to CAISO price spikes and troughs, particularly under the following conditions:

- When utility scale renewable generation and/or customer-owned DG over-produce relative to expectations, the CAISO market prices can be near zero or even negative; the excess generation is sold into the CAISO market at these low prices after purchasing that same renewable energy at the renewable energy premium price.
- When utility scale renewable generation and/or customer-owned DG under-produces relative to expectations, the CAISO market price can spike to over $1,000 per MWh and the LSE must make up for any shortfall in energy through the CAISO markets, with commensurate exposure to potentially very high prices and volatility.

The implication for CCA's looking to incorporate high levels of intermittent renewables is to identify and (initially) work with a portfolio manager (and scheduling coordinator) with the experience in forecasting and managing a similarly situated supply portfolio for a customer base that is also evolving in terms of load shape, including factors such as DG and PEV adoption. This relatively high proportional requirement for renewable generation is in nascent stages and is materially different than managing a traditional energy supply portfolio consisting of more predictable resources such as dispatchable fossil fuel-fired or hydroelectric generation.

CALIFORNIA RENEWABLE PORTFOLIO STANDARD CONSIDERATIONS

The following discussion centers around Renewable Portfolio Standard (RPS) considerations that factor into renewable resource procurement and pricing. Under the California law outlining the statewide RPS, CCAs, like other LSEs, will be required to procure at least 33% of their energy from renewable resources for their customers by 2020 and 50% by 2030.[1] Table E-1 summarizes RPS requirements in the state of California.

Table E-1: California Renewable Portfolio Standard Requirements

Compliance Period	Procurement Quantity Requirement
Compliance Period 3 (2017-2020)	2017 retail sales x 27% 2018 retail sales x 29% 2019 retail sales x 31% 2020 retail sales x 33%
2021-2029	Annual retail sales x 33%
2030 and beyond	Annual retail sales x 50%

Customer-owned DG, which is predominately solar PV, does not count towards the California RPS.[2] Only renewable generation supply procured by the LSE contribute towards meeting the RPS.

[1] CPUC RPS Homepage: http://www.cpuc.ca.gov/rps_homepage/
CEC Renewables Portfolio Standard (RPS) http://www.energy.ca.gov/portfolio/

[2] However, if the net energy metering customer exceeds their annual usage with DG output, that excess is eligible to provide Renewable Energy Credits (RECs) to the utility - http://www.cpuc.ca.gov/General.aspx?id=3800

Another aspect of the RPS that will impact CCA energy supply portfolios are the Portfolio Content Categories shown in Table E-2. Category 3 Renewable Energy Credits (RECs) are "unbundled," i.e., not associated with the actual purchase of renewable energy. Category 3 RECs are being phased out from RPS qualification. For 2017-2020, a maximum of 10% of the RPS requirement can be satisfied by Category 3 RECs. However, RPS contracts in excess of the RPS requirement could be comprised of Category 3 RECs.

Table E-2: RPS Portfolio Content Categories

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

The following formulaic examples illustrate how these categories impact supply using the contracted 2014 and 2020 RPS quantities cited for SDG&E:

- 31.6% of total energy supply from RPS-compliant renewable energy resources contracted for in 2014
    - 21.7% RPS requirement x 15% maximum Category 3 RECs = 3.25% of total energy supply can be comprised of Category 3 RECs
    - Excess RPS-compliant energy supply that *could be* Category 3 RECs: 31.6% actual 2014 RPS-compliant supply – 21.7% RPS requirement = additional 9.9% of total energy supply
    - 3.25% + 9.9% = maximum of 13.15% of total energy supply provided by Category 3 RECs
- 43.1% of total energy supply from RPS-compliant renewable energy resources currently under contract for 2020
    - 33% RPS requirement x 10% maximum Category 3 RECs = 3.3% of total energy supply can be comprised of Category 3 RECs
    - Excess RPS-compliant energy supply that *could be* Category 3 RECs: 43.1% RPS-compliant supply under contract – 33% RPS requirement = additional 10.1% of total energy supply
    - 3.3% + 10.1% = maximum of 13.4% of total energy supply provided by Category 3 RECs

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

- Assumed 43.1% of total energy supply from RPS-compliant renewable energy resources currently under contract for 2021
  - 33% RPS requirement x 0% maximum Category 3 RECs = 0% of total energy supply can be comprised of Category 3 RECs
  - Excess RPS-compliant energy supply that *could be* Category 3 RECs: 43.1% RPS-compliant supply assumed to be under contract for 2021 – 33% RPS requirement = additional 10.1% of total supply portfolio
  - 0% + 10.1% = maximum of 10.1% of total energy supply provided by Category 3 RECs

POWER PURCHASE AGREEMENT CONSIDERATIONS

In terms of CCAs, PPAs typically are long-term contracts to purchase energy from either conventional fossil fuel-fired or utility scale renewable generation resources owned by independent power producers. Typically, independent power producers will enter contractual agreements for approximately 80% of their capacity to cover their operations and maintenance cost and then trade in the CAISO market to achieve their profit margin.

In general, long-term PPAs spanning multiple years are used to meet demand requirements that are predictable (for example, the base load portion of an energy supply portfolio occurring in all forecast scenarios). The price for the PPA energy can take a number of forms, but typically either it is set at a known price that may escalate at a known escalation rate, or it is tied (indexed) to another market pricing indicator, such as the price of natural gas. Longer-term PPAs generally tend to be at a fixed volume and fixed price which provides for cost certainty and stability over the contract term. Other supply contracts are procured for 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 supply contracts are used to "shape" the supply profile to better match the forecasted demand.

Typically, shorter-term markets are used to procure the final supply requirements within the month, week, day, or hour. The CAISO provides markets for the day ahead and real time short-term energy products as well as third-party suppliers in the wholesale market. The Day-Ahead CAISO market is the forum to finalize the load forecast and either procure the additional energy required or sell any excess available from the supply portfolio. The Real-Time market then balances the day-of supply and demand and these are settled at the CAISO real-time market clearing price for purchase and sale.

In California, purchasing of energy is typically implemented with long-term PPAs. From the National Renewable Energy Laboratory's *Power Purchase Agreement Checklist for State and Local Governments*[4], advantages of PPAs to the City CCA program to purchase renewable energy include:

- No/low up-front cost[5];

[4] Power Purchase Agreement Checklist for State and Local Governments https://financere.nrel.gov/finance/content/power-purchase-agreement-checklist-state-and-local-governments

[5] The no/low up-front cost advantage assumes a solid credit capacity. There may be situations depending on how the CCA is formed that require some credit capability be extended to the CCA Entity in order to participate in PPA as well as CAISO markets.

- Ability for a tax-exempt entity, like the City, 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.

For the City CCA program, considerations for possible alternatives to PPAs include owning, leasing, or entering into partnerships to build renewable generation plants. Purchasing renewable generation would require financing, while leasing of solar generation is possible without up-front costs.

The power supply costs modeled in this Study do not include the costs for constructing City CCA program-owned or leased renewable generation facilities. Instead, a forecast of PPA pricing is used as the supply cost basis for this Study.

RESOURCE ADEQUACY CONSIDERATIONS

Two primary commodities—energy and capacity—comprise power procurement transactions in California. The energy commodity is traded through PPAs and the CAISO. The capacity commodity is purchased through bilateral agreements and typically solicited through a Request for Offer (RFO) process. Energy and capacity are often provided through the same PPA.

To ensure reliable grid operation, all LSEs including CCAs must provide reserve capacity. Thus, a CCA will need to plan, procure, and coordinate reserve capacity with the CPUC, the California Energy Commission (CEC), and CAISO. To do so, the CCA and its scheduling coordinator must file forms with the CPUC Energy Division, CEC, and CAISO to verify that the CCA meets the reserve requirements of the Resource Adequacy (RA) program. 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. These RA requirements impact the amount of supply a CCA must procure as well as compliance activities, which impact CCA load and price forecasts.

The RA program requires that LSEs, including CCA's, meet obligations including a Planning Reserve Margin. The RA program establishes deliverability criteria as well as system and local capacity requirements. The RA program also establishes rules for "counting" resources to meet resource adequacy obligations. Resources counted for RA purposes must be available to the CAISO for the full counted capacity. RA requirements under CAISO tariff provisions are intended to complement the State of California's efforts to implement resource adequacy programs.

The CPUC requires LSEs to demonstrate in both monthly and annual filings that they have purchased capacity commitments, or RA, of no less than 115% of their monthly peak demand. These purchase requirements are intended to secure sufficient commitments from actual, physical resources to ensure system reliability. The CPUC's RA program annually establishes minimum capacity obligation requirements for CPUC jurisdictional LSEs on a one year-ahead basis at both the system and local level. The key RA obligation is that a resource counted as "RA capacity" must either deliver energy to the LSE or bid into the CAISO energy markets or be available to produce electricity when needed. Each day, the CAISO runs a day-ahead integrated network model and dispatches resources efficiently to meet expected demand. All capacity designated as RA capacity can be scheduled to deliver energy by the CAISO if needed to maintain reliability. The RA program requires LSEs 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.

The RA process is not a static, unchanging set of procedures. Rather it's an evolving program with new procedures which may need to be completed by the City CCA program[6]. Currently, the CAISO conducts an annual and monthly RA planning process that requires LSEs, through scheduling coordinators, to submit RA plans. CCAs may use energy supply providers to satisfy these requirements. The RA plans identify the specific resources upon which the LSE is relying to satisfy forecasted monthly peak demand and reserve margin for the relevant reporting period[7]. To meet the current RA reporting requirements, CCAs must demonstrate the following reserve capacity requirements:

- Resource Adequacy Requirement (RAR) planning reserves are required to bring total capacity, including ISO required ancillary services, up to 115% of forecast load. Forecast load is based on a 1 in 2 (50% probability) year and baselined against the CEC forecast.
- Initially during early phases of CCA implementation, submit a load forecast two months before load serving begins and submit RA Filings specifying capacity to meet RA obligations one month before load serving begins.
- Once the CCA is established, demonstrate procurement of 90% of RAR one year ahead of time (due October 31) and demonstrate 100% of RAR each month. Monthly reports are due 1 -1.5 months ahead and summer months require 2 reports. The RAR is equivalent to 1.15 * the peak coincident load * .9 which is equivalent to 1.035 of the peak coincident demand.
- Submit RA compliance filings to the CPUC, CEC and CAISO using Excel 2007 (not 2003) format over the CPUC Secure FTP connection.
- Provide load forecast updates to the CEC yearly in January and March.
- Schedule the RA obligation into the Market Redesign and Technology Upgrade (MRTU) system[8]; or bid into day-ahead market, if not scheduled.
- RA obligation must be available in real time and is subject to the CAISO Residual Unit Commitment process at a $0 bid.

According to the CPUC[9]:

> *"A resource's Qualifying Capacity (QC) is the number of Megawatts eligible to be counted towards meeting a load serving entity's (LSE's) System and Local Resource Adequacy (RA) requirements. The*

[6] CPUC Resource Adequacy: http://www.cpuc.ca.gov/ra/

[7] CAISO Resource Adequacy Criteria and Must-Offer Obligations http://www.caiso.com/Documents/IberdrolaComments-FlexibleResourceAdequacyCriteriaMustOfferObligation-FourthRevisedStrawProposal.pdf

[8] MRTU modification in 2009 to CAISO markets was intended to increase grid and market efficiencies, a reduction of barriers to alternative resources of power, and better management of transmission bottlenecks and dispatching the least cost power plants. The modification also assists in determining how much of a generation resource's capacity should be provided through PPA, and CAISO day-ahead, and real-time markets. The MRTU optimization of this balance is intended to ensure an efficient supply chain for each aspect of power procurement.: https://www.caiso.com/Documents/MarketsandPerformance_MAP_InitiativeSummary.pdf

[9] CPUC Energy Division, Draft Staff Proposal Resource Adequacy Proceeding R.11-10-023, Qualifying Capacity and Effective Flexible Capacity Calculation Methodologies for Energy Storage and Supply-Side Demand Response Resources, September 13, 2013: www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6553

revised QC that incorporates deliverability constraints is called the Net Qualifying Capacity (NQC). A resource's Effective Flexible Capacity (EFC) is the number of Megawatts eligible to be counted towards meeting an LSE's Flexible Resource Adequacy (RA) requirements10."

This new flexible RA requirement is intended to ensure capacity is contracted with resources that can quickly respond if renewable resources do not perform as expected or come on line quickly when there is a rapid change in renewable output (like the PV generation decrease at sunset).

ENERGY STORAGE CONSIDERATIONS

Assembly Bill 2514, and the corresponding CPUC Storage Rulemaking (R.10-12-007[11]), requires electric service providers to acquire energy storage.[12] The CPUC has determined that this law also applies to CCAs. Thus, a CCA will need to procure energy storage, which it may then be able to use to satisfy RA requirements.

The CPUC decision sets a target for CCAs and other LSEs to procure energy storage equal to 1% of their yearly peak load by 2020, with installations being operational no later than 2024. Beginning in January 2016, all LSEs are required to file a report demonstrating their compliance to meet the target and describing their methodologies for cost-effective projects.

For purposes of this Study, we assumed that the San Diego CCA maintains energy storage capacity equivalent to the 1% of the annual peak load in compliance with AB 2514.

ENERGY SUPPLY MANAGEMENT CONSIDERATIONS

Energy procurement is similar to other commodity trading. When demand is high and capacity to supply is approaching 100% utilization, the prices are high. When demand is low and capacity to supply is substantially underutilized, pricing is low. However, electricity is different because the consumers do not receive direct or immediate feedback regarding the cost of supply. The retail electricity rates are instead based in part on the average pricing of the electricity supply determined over some period of time.

The CCA will procure power through a variety of mechanisms including bilateral agreements of varying term lengths and spot market purchases. The CCA will seek to optimize its power procurement strategy to balance cost and risk. For example, PPAs lock in a specific volume of supply at defined pricing terms. When consumer electricity demand exceeds PPA quantities, the LSE (CCA or IOU) must procure supply from the California Independent System Operator (CAISO) day-ahead and real-time markets and will be exposed to price risk. Similarly, over-procurement through PPAs, exposes the LSE to price risk when the excess supply is sold at the prevailing CAISO day-ahead and real-time market prices.

[10] CAISO Flexible resource adequacy criteria and must offer obligations: https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx

[11] 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/word_pdf/FINAL_DECISION/128658.pdf

[12] CPUC Energy Storage Overview: http://www.cpuc.ca.gov/General.aspx?id=3462

Power market prices are continually changing, even for longer term, multi-year supply contracts. Generally, the shorter the contract term, the higher the potential is for over-all portfolio price volatility. This is why a supply portfolio will consist of a mixture of long-term, mid-term and short-term supply contracts.

The development and management of this supply portfolio can be managed in numerous ways by the CCA Program. The CCA Program can take a proactive management role and develop all the electric operations functions internally, including. electric supply procurement which include capacity, resource adequacy requirements, ancillary services, risk management processes and programs required to manage the supply portfolio, long- and short-term load forecasting and scheduling coordination. As an alternative, these functions can be outsourced to third parties. 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 the CCA Program's delivery point at a fixed price. While convenient, these types of contracts will generally come with a premium price, in particular if pricing is fixed and/or over a longer term, and may end up being more expensive than the IOU 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 shaped energy or a simple volume-of-energy product at a fixed price over one, two, or three-year terms. The shaped energy product would be delivered to the CCA Program delivery point with the monthly fixed volumes based on CCA's historic load profile, at either 100% of historic load or some equally weighted percentage of load. Any actual use above or below the historic load levels would be purchased or sold into the CAISO Day Ahead market. Purchases and sales could be settled at the actual CAISO Day Ahead price or another settlement formula (e.g., the load-weighted average of the CAISO hourly Day Ahead market prices at the SCE load aggregation point). Other energy supply-related products and their associated costs could be broken out as separate products (e.g. resource adequacy, ancillary services, schedule coordination services, etc.) to create price transparency for San Diego CCA. This approach will carry a premium to cover the supplier's risk exposure, but because volumes are fixed, the exposure is less thus the premium will be lower compared to the full requirements approach.

Other portfolio management structures are certainly possible. However, the structure that will work best for the CCA Program is a function of risk appetite and tolerance, resource availability, skill set, and cost structure. A third party outsourcing approach may make sense in the early years of the CCA Program which allows it to gain experience and confidence as customer groups are phased into the program.

Because power market prices are continually changing, realistic costs can only become known when the CCA's power requirements, cost structure, and basic terms and conditions are known and providers respond with binding proposals. The goal of evaluating various procurement scenarios is to identify current and potential options for the CCA Program to meet forecasted electricity demand. This includes evaluation of a power procurement strategy, alternative generation resources available, and the attributes and performance characteristics of the available generation resources. Just as correlated factors (such as time of year, day of the week, and temperature) can be used to estimate varying electricity demand, similar correlated factors can be used to estimate variable renewable resource generation. The CCA Program will need to examine how these potential resource options best fit within the procurement strategy. The CCA Program will likely seek to incorporate local renewable energy into its supply portfolio by potentially contracting for utility scale solar and/or wind generation, as well tapping into the growing portfolio of distributed generation resources in and around San Diego. In order to develop CCA business and implementation plans, the CCA will need an understanding of the renewable generation resources currently in the area as well as a forecast for new generation.

ENERGY SUPPLY COST DEVELOPMENT

The load forecast outlined in Appendix D provides the basis to develop the City CCA program's energy supply costs. The following factors for developing the energy supply portfolio costs of the City CCA program were analyzed as a part of this initial feasibility analysis. Each of the bulleted items below was analyzed to identify the average and standard deviation for any given hour of every month. This average and variation were used to identify the potential range of operating conditions.:

- Electricity Load – As discussed in Appendix D, load forecasts were based on the 2013-15 data provided by SDG&E, and the customer load for each rate classification of customer was analyzed. The time of year has a significant impact on energy demand and resulting energy supply costs. For example, in Southern California, summer hours in late afternoon have typically the highest demand and highest market prices due to the air conditioning system load. In late December, there is a noticeable demand increase at sunset due to the number of holiday lights that are switched on by daylight sensors. These month and time of day factors were considered as part of the analysis.
- Customer-Owned Solar PV Output – Based on the National Renewable Energy Laboratory (NREL) PVWatts[13] analysis tool, an estimated solar output was developed based on historical and projected numbers of solar installations.
    - The projected growth in Customer-Owned Solar PV Output is detailed in Appendix D Load Forecast Development.
    - The NREL PVWatts tool estimates the output of fixed panel solar photovoltaic based on the forecasted capacity of customer owned solar PV systems and time of day throughout the year. The output from customer owned solar was deducted from the amount of load served by the CCA.
    - The variability of the customer owned solar was also included in the MCSM model to which adds to the variability of the customer load itself.
- Power Procurement Costs
    - Renewable PPAs as described further in segment titled "Renewable Power Purchase Agreement Costs"
    - Natural Gas PPAs as described further in segment titled "Natural Gas Power Purchase Agreement Costs"
    - CAISO market purchases/sales as described further in segment titled "CAISO Market Costs"
- Day Ahead market prices – Historic locational marginal pricing (LMP) was used as the basis for future years' price forecast and expected volatility

[13] National Renewable Energy Laboratory (NREL) PVWatts™ Site Specific Data Calculator http://pvwatts.nrel.gov/

- Real-time market prices - Historic Real-time LMP was used as the basis for future years' price forecast and expected volatility

The following additional assumptions and qualifications were made:

- No separate operating and maintenance responsibilities or resultant costs were included in the estimated cost of power procurement as these costs are assumed to be included in the negotiated PPA pricing.
- With bilateral energy and resource adequacy contracts there are often credit and collateral provisions in the contract. For example, suppliers may provide options for extending financial credit to the CCA. However, no costs associated with establishing needed credit capacity were included in this Study.
- The cost estimates developed for PPAs for renewable and natural-gas fired generation will vary from the existing IOU portfolio costs which incorporate self-generation and confidential PPA contracts with varying origination dates, durations, and prices. These existing contracts could have been signed any time after the year 2001 and the California electricity crisis.[14] Additionally, the estimated procurement costs may vary with other CCAs due to each CCA's PPA contract provisions in addition to the locational marginal pricing of the CAISO as described in the segment titled "CAISO Market Costs."

Once the various cost components were developed, a Monte Carlo simulation was run to evaluate a range of possible outcomes for energy supply costs. The Monte Carlo simulation (discussed further in the segment titled "Monte Carlo Energy Supply Portfolio Cost Analysis") combined the variability in load with the load growth forecast, the customer-owned solar PV forecast, and other variables to estimate short-term, medium-term and long-term electricity demand that the City CCA Program will have to supply.

The following segments provide the assumptions and methodology used to develop the various components of the energy supply costs including renewable generation PPAs, natural gas generation PPAs, CAISO market purchases/sales, as well as capacity and resource adequacy costs. The cost forecasts discussed here provide the basis for the Monte Carlo energy supply portfolio cost analysis.

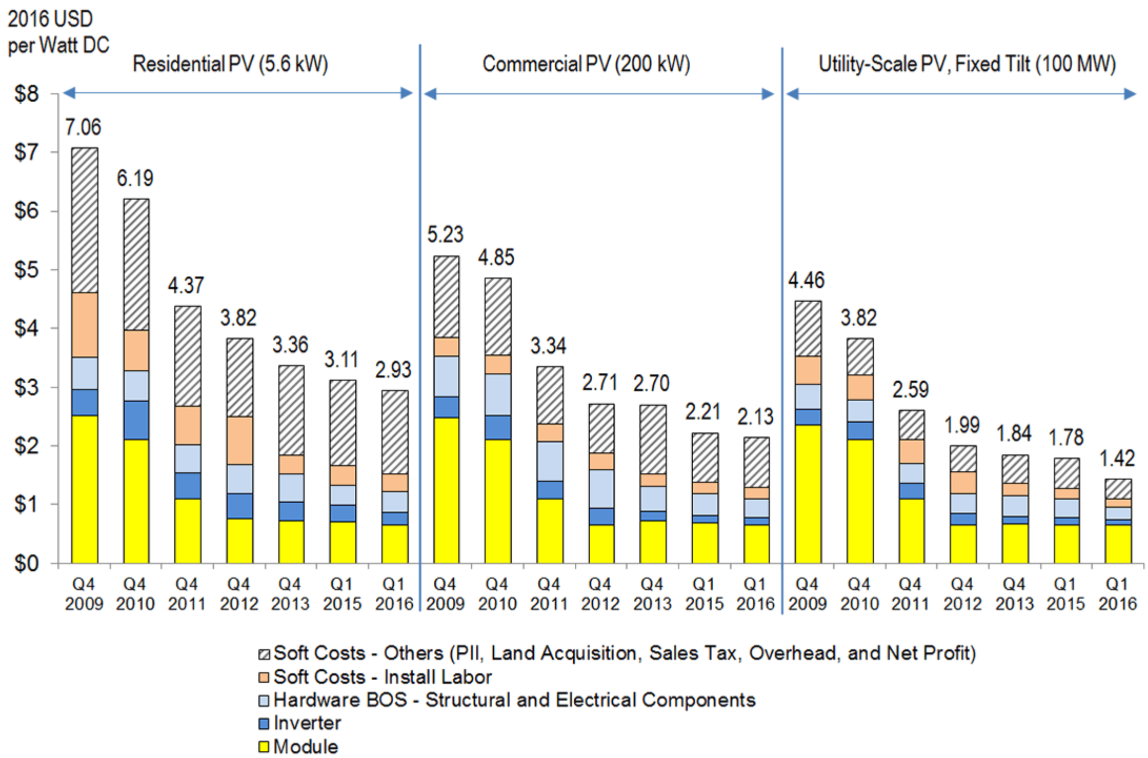
RENEWABLE POWER PURCHASE AGREEMENT COSTS

Historical data provides a general understanding that the cost of renewable energy is decreasing. The 2016 NREL U.S. Solar Photovoltaic System Cost Benchmark Report[15] states that utility-scale (> 2MW) photovoltaic systems have reached $1.42 per Watt DC (or $1.99 per Watt AC) for fixed-tilt systems, and $1.49 per Watt DC (or $1.79 per Watt AC) for one-axis-tracking systems. NREL's historical PV system cost trends, for residential, commercial, and utility-scale installations, are illustrated in Figure E-1.

[14] EIA Subsequent Events California's Energy Crisis summary: https://www.eia.gov/electricity/policies/legislation/california/subsequentevents.html

[15] NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016 http://www.nrel.gov/docs/fy16osti/66532.pdf

Figure E-1: Replica of NREL PV System Cost Benchmark Summary (inflation adjusted), Q4 2009 – Q1 2016[16]



However, according to the CPUC's Q1 2016: Biennial RPS Program Update,[22] the California IOUs' RPS procurement costs have been increasing since 2011 as shown in Figure E-2. This disconnect between national trends and actual RPS procurement costs in California may be in part due to the RPS program itself.[17] The initial 2002 RPS applied only to IOUs. RPS procurement costs initially increased until 2008 and then declined until 2011. In 2011, Senate Bill X1-2 (SBX) expanded RPS to municipal utilities, electric service providers, and CCAs.[18] Prior to SBX, many of these LSEs had not been aggressively pursuing renewable generation portfolios.

As a result of the expansion of the RPS mandate in 2011, there appears to be a classic supply and demand interplay: increased demand for RPS-compliant resources may be driving up cost due to supply

[16] Figure from NREL Report shows U.S. solar PV costs continuing to fall in 2016, September 28, 2016: http://www.nrel.gov/news/press/2016/37745

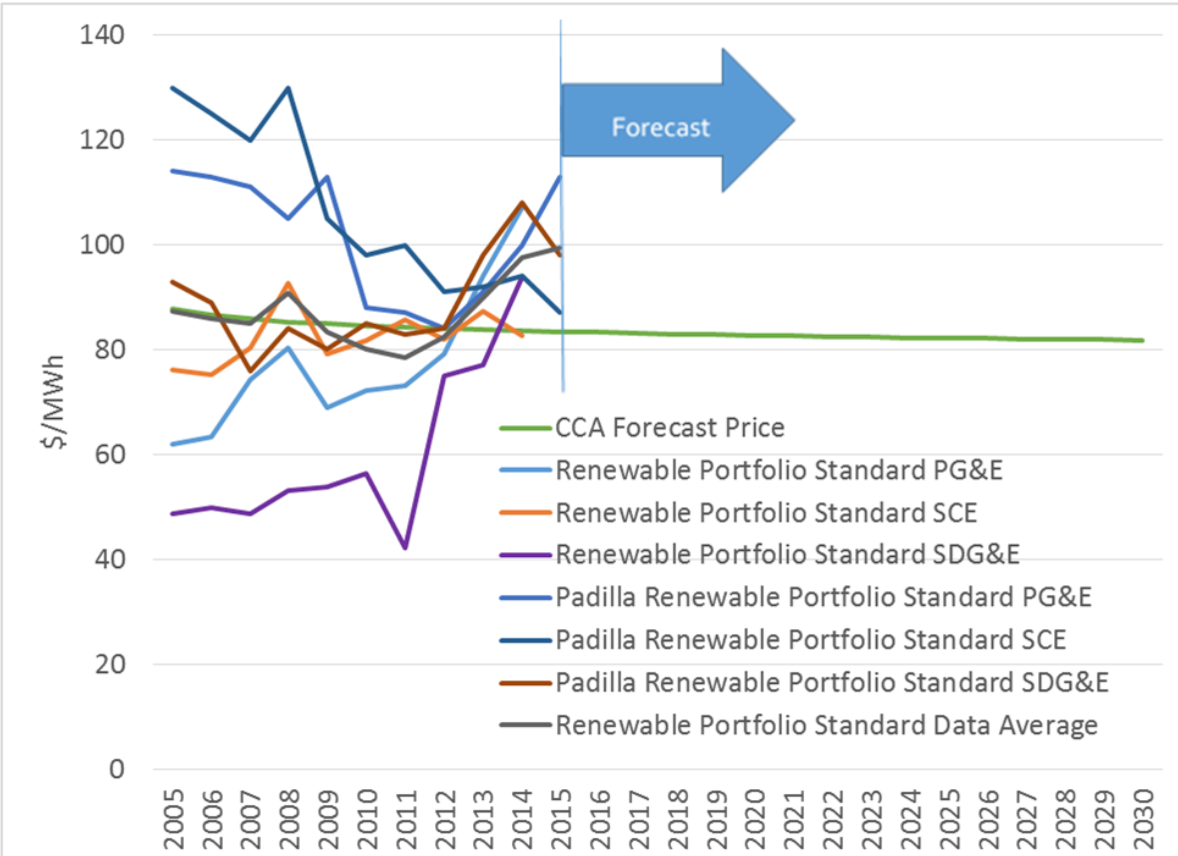
USD = United States Dollar; DC = Direct Current; PV = Photovoltaic; PII = permitting, inspection and interconnection; BOS = balance of system; Q1 = 1st Quarter; Q4 = 4th Quarter

[17] CPUC RPS Program Overview http://www.cpuc.ca.gov/RPS_Overview/

[18] CEC Renewables Portfolio Standard Reports and Notices from Publicly Owned Utilities: http://www.energy.ca.gov/portfolio/rps_pou_reports.html ; CPUC RPS Program Overview: http://www.cpuc.ca.gov/RPS_Overview/

constraints. The Padilla Report[19] to the California Legislature for 2015 Renewable Procurement Costs begins to show that supply may be increasing to meet the additional demand, as depicted in Figure E-2.[20] This Study combined all of the data sources identified in Figure E-2, including the IOUs' RPS filings and the Padilla report, to develop the forecasted utility scale renewable generation cost forecast[21] used in the Monte Carlo energy supply portfolio cost analysis.

Figure E-2: IOU RPS Compliance Cost[22]



[19] 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 Report 2016 -Final - Print.pdf

[20] 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."

[21] In this instance, a regression analysis using logarithmic least squares fitting was used: http://mathworld.wolfram.com/LeastSquaresFittingLogarithmic.html

[22] 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

An AB67 legislative report[23] also speculated on the reason for the increasing and decreasing cost for utility scale bulk renewable generation:

> *"From 2003 to 2014, the average TOD-adjusted price of contracts approved by the CPUC has increased from 5.4 cents to 7.6 cents/kWh in nominal dollars, and decreased from 8.2 cents to 7.6 cents/kWh in real dollars. One reason for this increase in nominal pricing is that the IOUs contracted with existing renewable facilities at the beginning of the RPS program and with mostly new facilities in more recent years in order to meet the 20% and 33% RPS targets. These new facilities typically result in higher contract costs in order to recover the capital needed to develop new facilities. Having said that, the decrease in RPS contract prices in terms of real dollars indicates that the renewable market in California is robust and competitive and has matured since the start of the RPS program."*

NATURAL GAS POWER PURCHASE AGREEMENT COSTS

A large portion of the annual electricity supply in California and the SDG&E service territory comes from natural gas. Table E-3 depicts the sources of energy supply by type for SDG&E, with natural gas comprising 54% of the power mix for 2015.

[23] 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

Table E-3: 2015 SDG&E Power Content Label[24]

POWER CONTENT LABEL		
ENERGY RESOURCES	SDG&E 2015 POWER MIX (Actual)	2015 CA POWER MIX**
Eligible Renewable	**35%**	**22%**
-- Biomass & waste	2%	3%
-- Geothermal	0%	4%
-- Small hydroelectric	0%	1%
-- Solar	18%	6%
-- Wind	15%	8%
Coal	0%	6%
Large Hydroelectric	0%	5%
Natural Gas	54%	44%
Nuclear	0%	9%
Other	0%	0%
Unspecified sources of power*	**11%**	**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 **SDG&E**. For general information about the Power Content Label, contact the California Energy Commission at 1-844-217-4925 or http://www.energy.ca.gov/pcl/.

It is assumed that the City CCA program will need to secure at least a portion of its energy supply portfolio from natural-gas fired generation resources, depending on the renewable portfolio content (RPC) Scenario examined. The Study assumes that the bulk of this natural gas energy supply will come from PPAs.

Existing PPAs between LSEs and independent power producers are confidential contracts. As a result, actual historical contractual pricing is not available for this Study. However, multiple alternative sources of data and information can provide insight into the likely range of bilateral PPA prices for natural gas generation for the City CCA program. Forecasting the efficiency of natural gas-fired generation, or how much fuel is required to produce a unit of energy, and the price of natural gas, the analysis derives the forecasted cost of natural gas generation.

The U.S. Department of Energy's Energy Information Administration (EIA) tracks the monthly price of natural gas sold to the electric power industry[25] in dollars per thousand cubic feet (Mcf), which is roughly equivalent to dollars per million British Thermal Units (MMBTU).[26] A generation unit's "heat rate" measures the efficiency of converting the fuel to energy and is typically expressed as BTU per kWh. The

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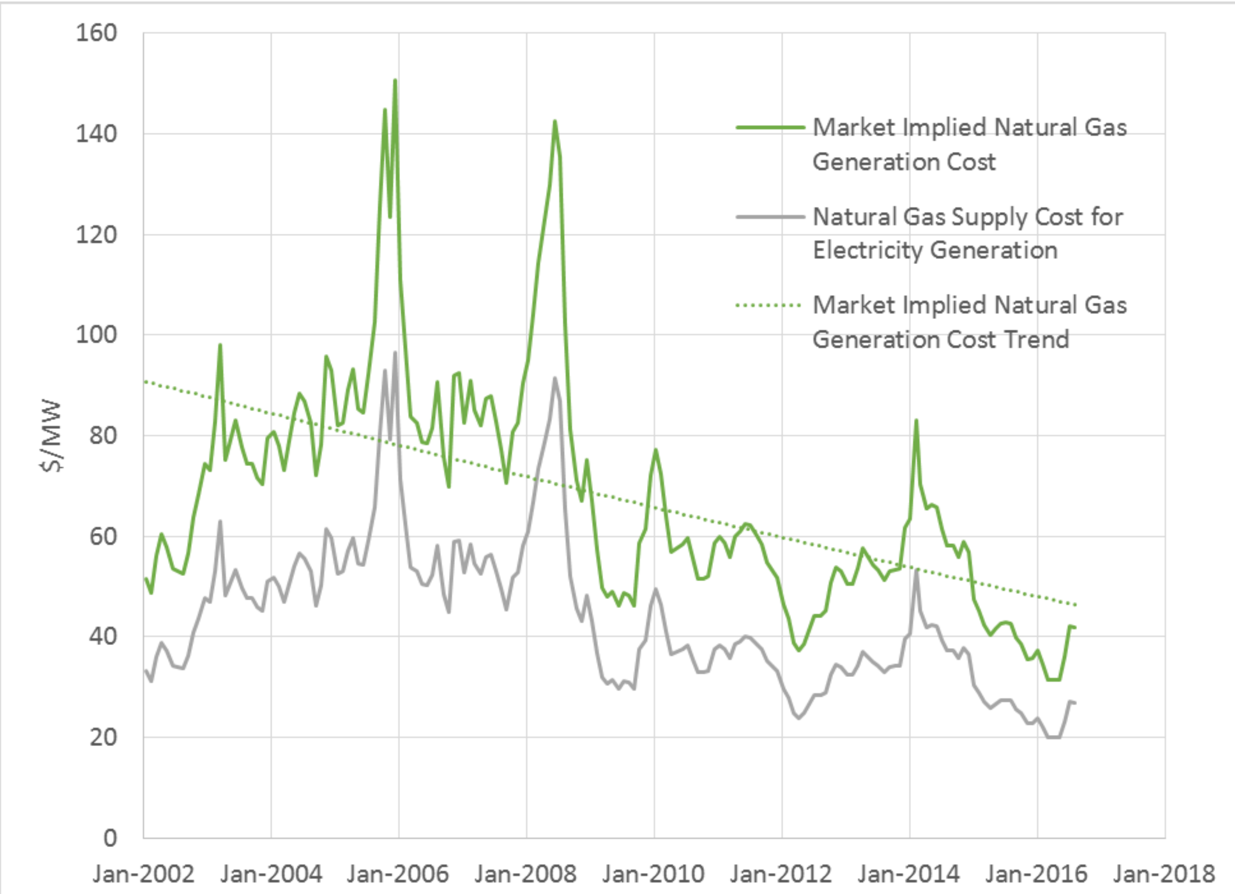
[24] Power Content Label required by AB 162 (Statute of 2009) and Senate Bill 1305 (Statutes of 1997): http://www.energy.ca.gov/pcl/labels/

[25] EIA California Natural Gas Price Sold to Electric Power Customers: https://www.eia.gov/dnav/ng/hist/n3045ca3m.htm

[26] How Natural Gas is Measured http://www.tulsagastech.com/measure.html

CEC 2015 Update of the Thermal Efficiency of Gas-Fired Generation in California[27] estimates the 2014 average heat rate to be 7,760 BTU per kWh. Combining these data results in an approximate natural gas supply cost, expressed in $ per MW, and as shown in Figure E-3 with the lower gray line labeled "Natural Gas Supply Cost for Electricity Generation."

Figure E-3: California Natural Gas Generation Cost based on Natural Gas Price and Heat Rate Conversion

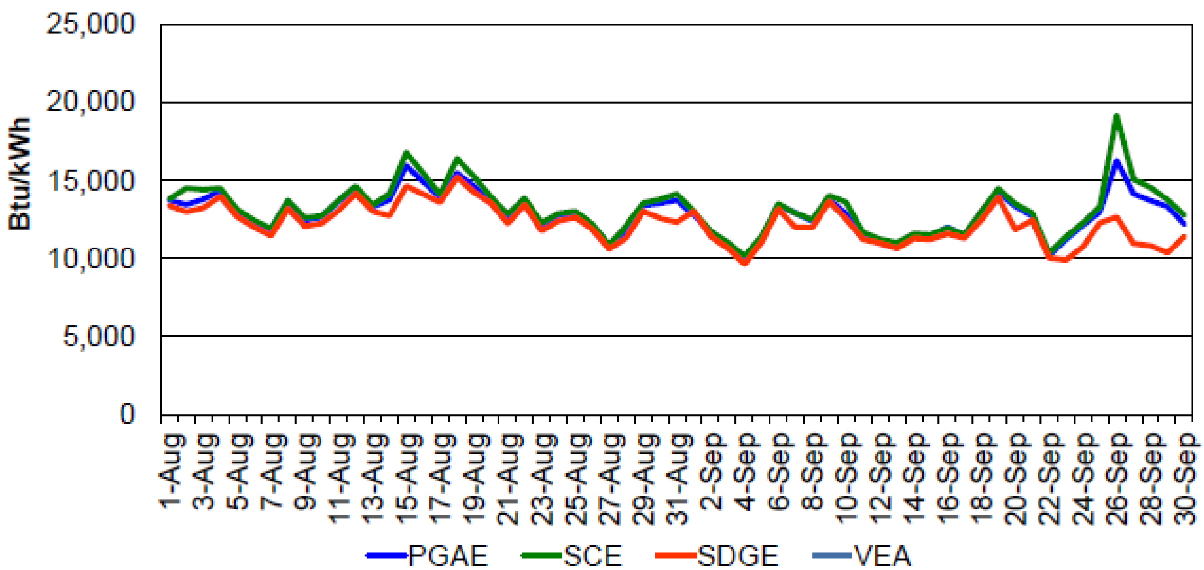


Additionally, the monthly CAISO Market Performance Metric Catalog[28] derives a Daily Integrated Forward Market Default Load Aggregation Point (DLAP) Market Implied Heat Rate as shown in Figure E-4. While the EIA heat rate data indicated a recent range of 7,500 to 8,000 BTU per kWh for California, the CAISO market implied heat rate for 2016 shows a range of 10,000 to 15,000 BTU per kWh.

[27] 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

[28] CAISO Market Performance Metric Catalog: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AF1E04BD-C7CE-4DCB-90D2-F2ED2EE8F6E9

Figure E-4: Replica of Market Performance Metric Catalog for September 2016 Daily IFM Default Load Aggregation Point Market Implied Heat Rate[29]

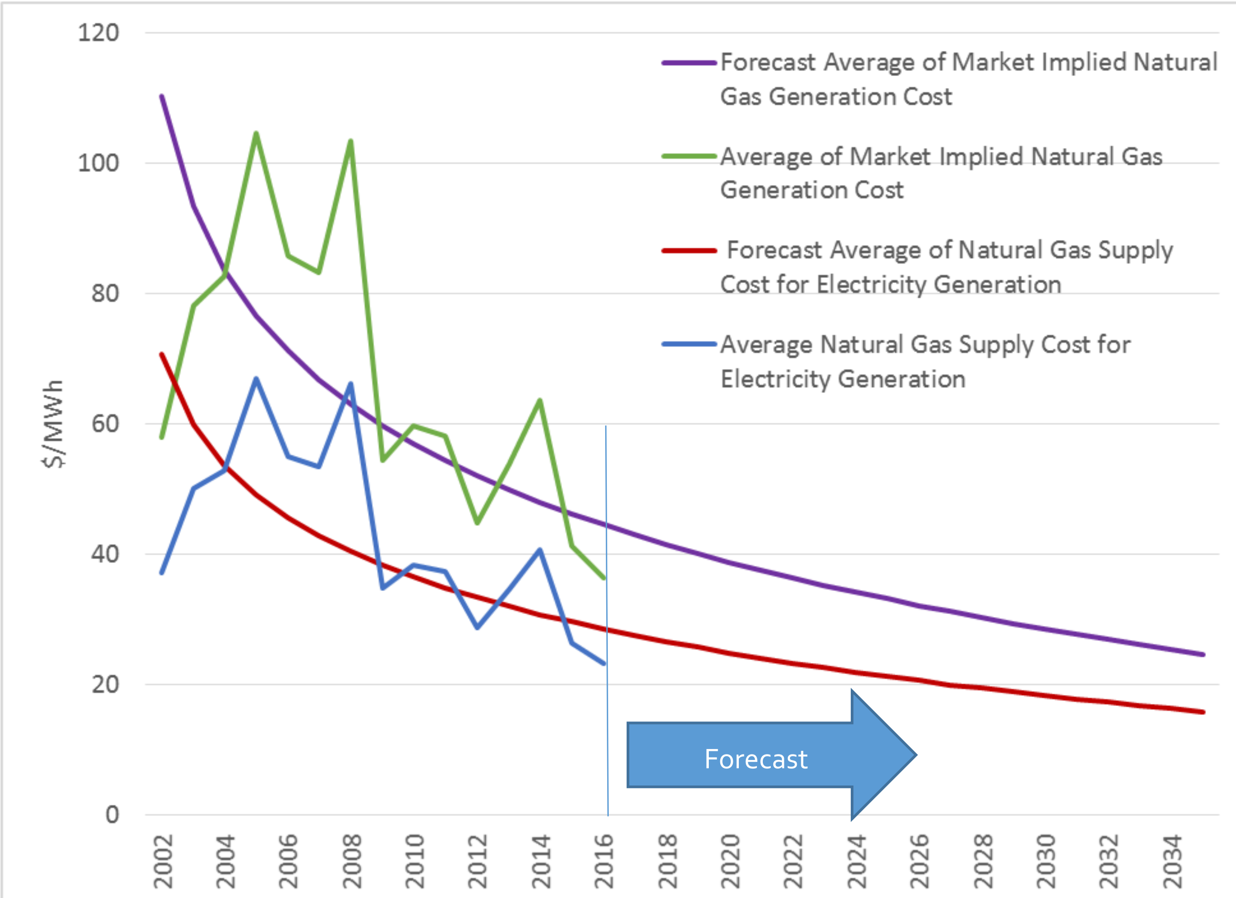


This 33-87% markup represents the difference between the fuel cost for natural gas generation units and the sale price of their energy, and is also reflected as Market Implied Natural Gas Generation Cost in Figure E-3.

Combining the EIA California Natural Gas Generation Cost based on Natural Gas Price and Heat Rate Conversion with the CAISO market implied heat rate as well as the improvement in natural gas generation heat rate (efficiency), the forecast of natural gas generation supply cost was developed, as shown in Figure E-5. This Study then used the "Average of Market Implied Price" in Figure E-5 to develop the forecasted natural gas generation cost used in the Monte Carlo energy supply portfolio cost analysis.

[29] Market Performance Metric Catalog for September 2016:
https://www.caiso.com/Documents/MarketPerformanceMetricCatalogforSep2016.pdf
PGAE = Pacific Gas & Electric; SCE = Southern California Edison; SDGE = San Diego Gas & Electric; VEA = Valley Electric Association

Figure E-5: Natural Gas Generation Supply Cost



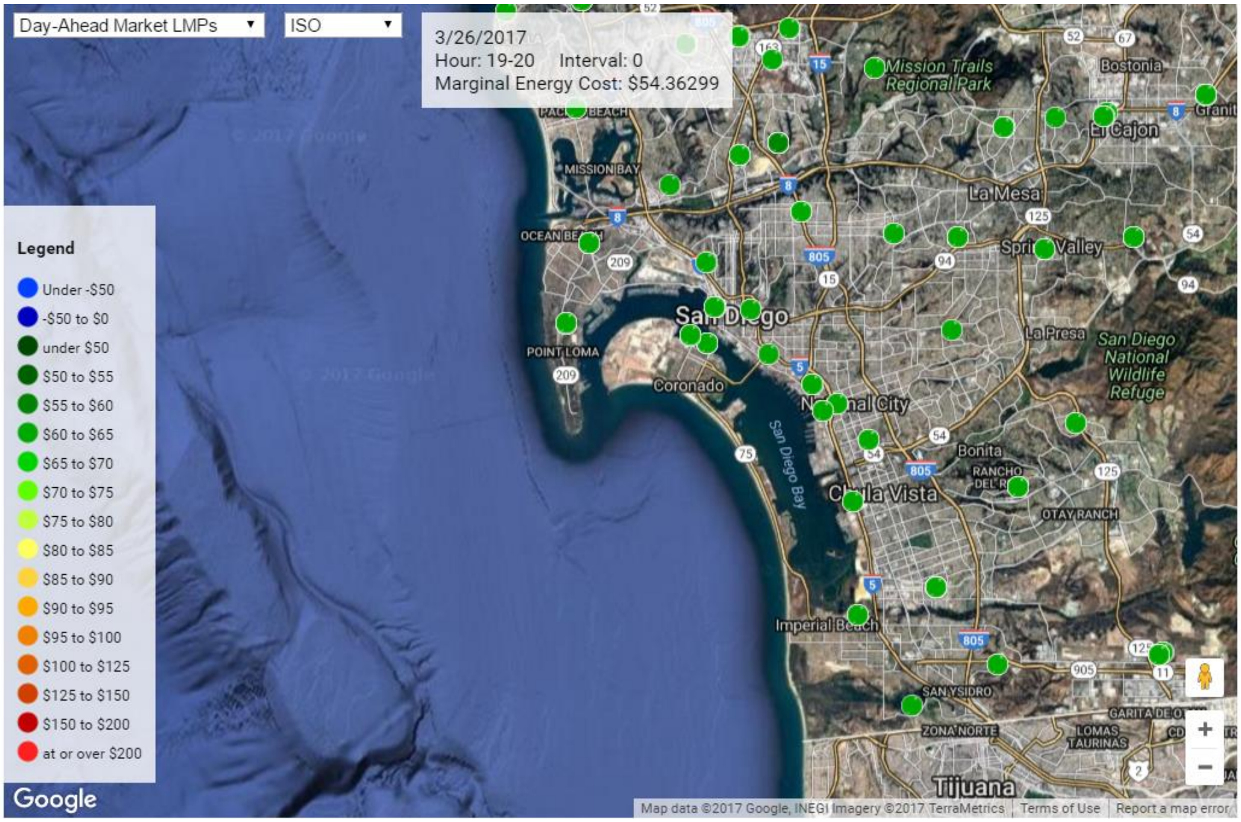
CAISO MARKET COSTS

The Study assumes that the CCA will generate power and/or use PPAs to purchase the majority of energy to serve customer needs, rather than buying from the short-term market. However, load forecasts are never perfect and PPAs will never exactly align with demand. Quantities to supplement self-generation and PPA supply are purchased from the CAISO day-ahead and real-time markets that balance supply and demand for participating LSEs. This Section discusses how pricing for CCA supply from day-ahead and real-time markets was determined.

CAISO utilizes 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. The City of San Diego is served by multiple price nodes (pNodes) with different LMPs as can be seen in the CAISO LMP contour map[30] illustrated in Figure E-6. The SDG&E DLAP is the weighted average price for all pNodes within SDG&E service territory.

[30] California ISO Market price maps: http://www.caiso.com/pages/pricemaps.aspx

Figure E-6: March 26, 2017 CAISO LMP Map for San Diego.



Using a map of the City of San Diego boundary in combination with the CAISO market price map, pNodes were identified (listed in Table E-4) to analyze the CAISO day-ahead and real-time energy costs within the City of San Diego. The San Diego pNode analysis essentially develops a San Diego DLAP and provides insight into historical prices and price volatility. This analysis also determines whether the prices and volatility are less than or greater to that in the larger SDG&E service territory DLAP or, more broadly, the State of California.

Table E-4: CAISO pNodes identified within the City of San Diego

CAISO pNodes identified within the City of San Diego				
ARTESN_6_N001	B_6_N003	B_6_N005	B_6_N007	BERNARDO_6_N001
BERNARDO_6_N009	BERNARDO_6_N014	CABRILLO_1_N001	CABRILLO_6_N001	CABRILLO_6_N004
CABRILLO_6_N011	CARLTNHS_1_N004	CARLTNHS_1_N011	CARLTNHS_1_N012	CENTERS_6_N004
CENTERS_6_N008	CHCARITA_1_N004	CHCARITA_1_N008	CHCARITA_1_N012	CHOLLAS_6_N001
CHOLLAS_6_N008	CLAIRMNT_6_N001	CLAIRMNT_6_N008	DELMAR_6_N001	DELMAR_6_N010
DELMAR_6_N011	EASTGATE_6_N004	EASTGATE_6_N101	EASTGATE_6_N201	ELLIOTT_6_N001
ELLIOTT_6_N004	F_6_N001	F_6_N002	F_6_N005	FENTON_6_N001
FRIARS_1_N001	GENESEE_6_N001	GENESEE_6_N005	GENESEE_6_N011	GENESEE_6_N015

CAISO pNodes identified within the City of San Diego				
KEARNEY_7_N001	KETTNER_6_N001	KETTNER_6_N004	KYOCERA_6_N001	LAJOLLA_6_N001
LAJOLLA_6_N007	MESAHGTS_6_N007	MESAHGTS_6_N011	MESARIM_6_N001	MESARIM_6_N007
MESARIM_6_N008	MIRAMAR_6_N001	MIRAMAR_6_N004	MIRAMAR_6_N017	MIRAMREF_7_B1
MISSION_2_N035	MISSION_6_N031	MISSION_6_N040	MISSION_6_N049	MISSON_1_N015
MRGT_6_NODE1	OLDTOWN_6_N002	OLDTOWN_6_N003	PACFCBCH_6_N001	PACFCBCH_6_N004
POINTLMA_6_N001	POINTLMA_6_N014	POINTLMA_6_N021	RCARMEL_6_N001	RCARMEL_6_N004
RCARMEL_6_N011	ROSECYN_6_N017	SAMPSON_6_N010	SCRIPPS_6_N001	SCRIPPS_6_N008
SCRIPPS_6_N013	STREAMVW_6_N007	TOREYPNS_6_N001	TOREYPNS_6_N007	TOREYPNS_6_N008
TOREYPNS_6_N008	UCM_6_N001	UCM_6_N002	UCM_6_N006	URBAN_6_N001
URBAN_6_N009				

Day-Ahead Market Locational Marginal Price

A portion of the CCA market purchases will be made in the CAISO day-ahead market. The CAISO day-ahead pricing is posted on a platform known as the Open Access Same-time Information System (OASIS).[31] CAISO day-ahead prices obtained from OASIS, as shown in Figure E-7, show significant variability and volatility when compared to the range of likely costs for the PPA contracts shown in Figure E-5.

[31] California ISO Open Access Same-time Information System (OASIS) http://oasis.caiso.com/mrioasis

Figure E-7: San Diego Average CAISO Day-Ahead Pricing

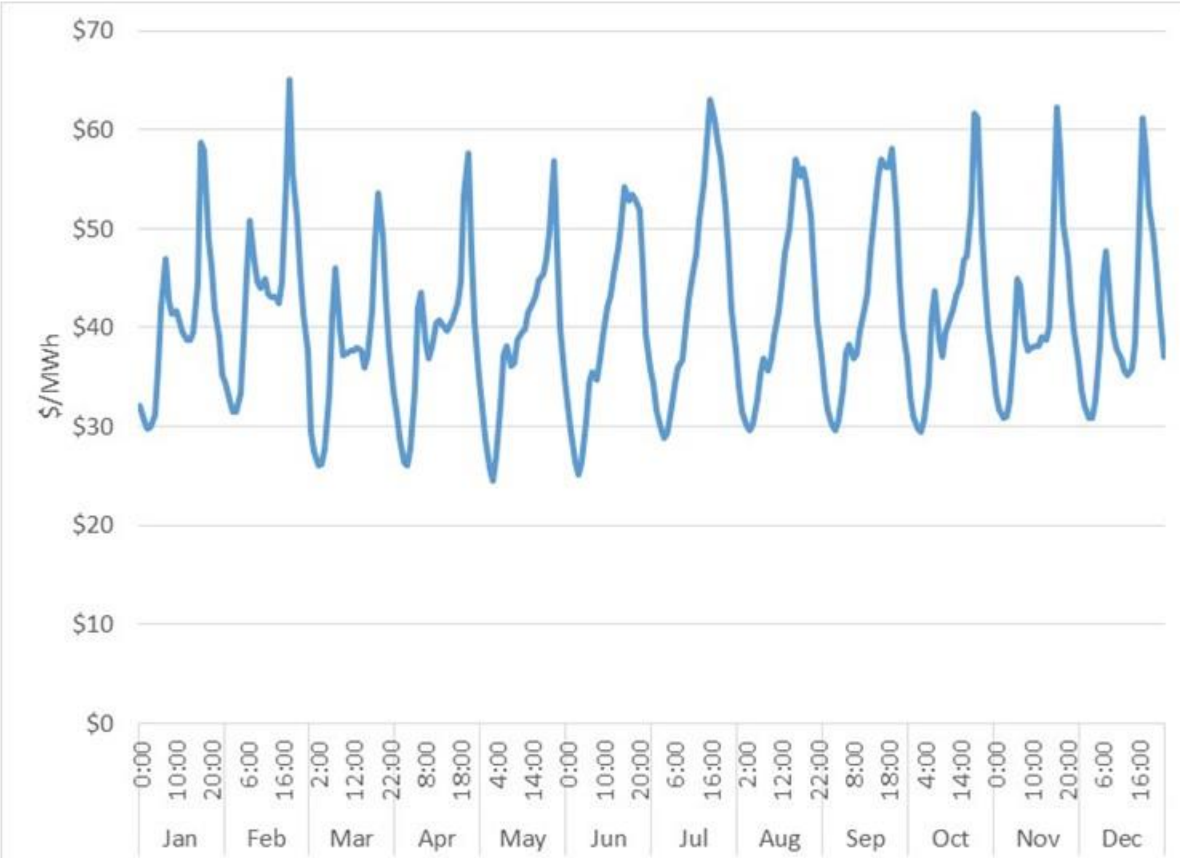
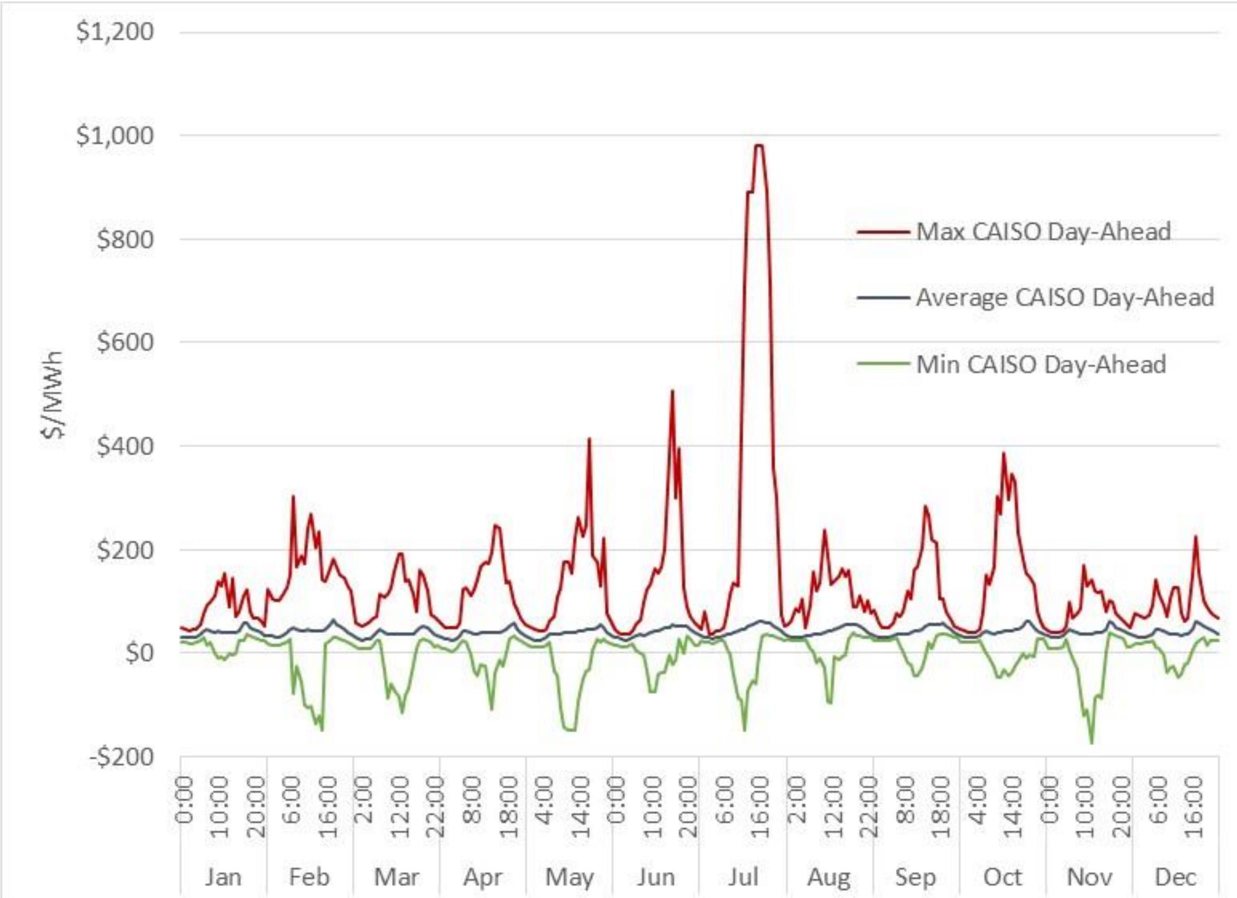


Figure E-8 illustrates the maximum, average and minimum range for CAISO DLAP pricing for SDG&E. Illustrating the volatility of recent day-ahead market activity, SDG&E DLAP pricing in May of 2016 ranged from $-0.70 to $194.53 per MWh. Negative pricing indicates the CAISO has excess generation that cannot 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 $194.53 translates to $0.19453 per kWh.

Figure E-8: Maximum, Average and Minimum Hourly CAISO Day-Ahead SDG&E DLAP Pricing



CAISO Real-time Market CCA Pricing

A portion of the City CCA program's market purchases will be procured in the CAISO real-time market. The CAISO 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 are market products that serve the real-time balancing needs for electricity supply and demand.

Real-time market costs for the CCA were estimated using the real-time five-minute interval LMP data from CAISO OASIS.[32] As can be seen by comparing Figures E-8 and E-10, the volatility and price magnitude of the real-time market is significantly greater than that of the day-ahead market.

[32] California Independent System Operator (CAISO) Open Access Same-time Information System (OASIS) http://oasis.caiso.com/mrioasis

Figure E-9: Hourly Average of CAISO Real-Time SDG&E DLAP Cost

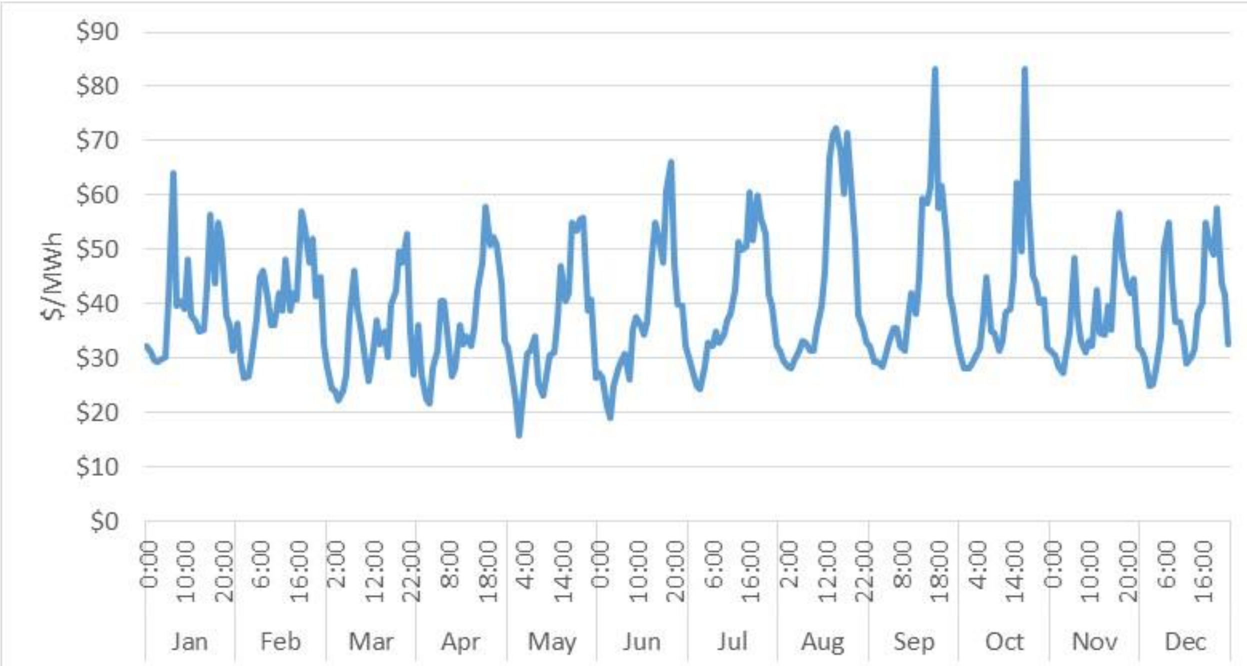
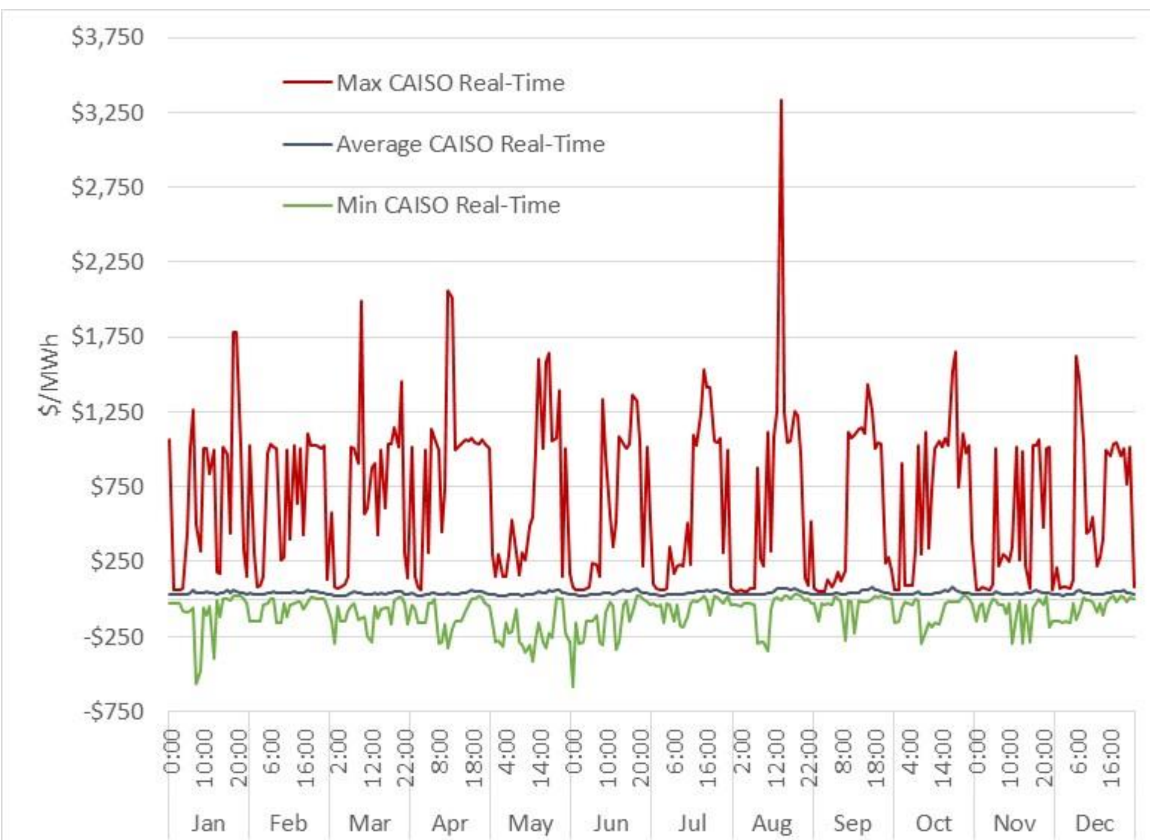


Figure E-10: Maximum, Average and Minimum CAISO Real-Time SDG&E DLAP Pricing



CAISO Price Extremes and Volatility

The amount of renewable resources on the system impacts CAISO power prices which impacts the City CCA program's energy supply costs. Essentially, if there is more renewable generation than expected from customer-owned solar PV DG and/or utility scale renewable generation, then prices can be very low or negative as long as the supply exceeds demand. Similarly, if renewable generation is less than expected, then CAISO prices increase to entice additional generation resources to make up the shortfall. The following conditions drive price extremes:

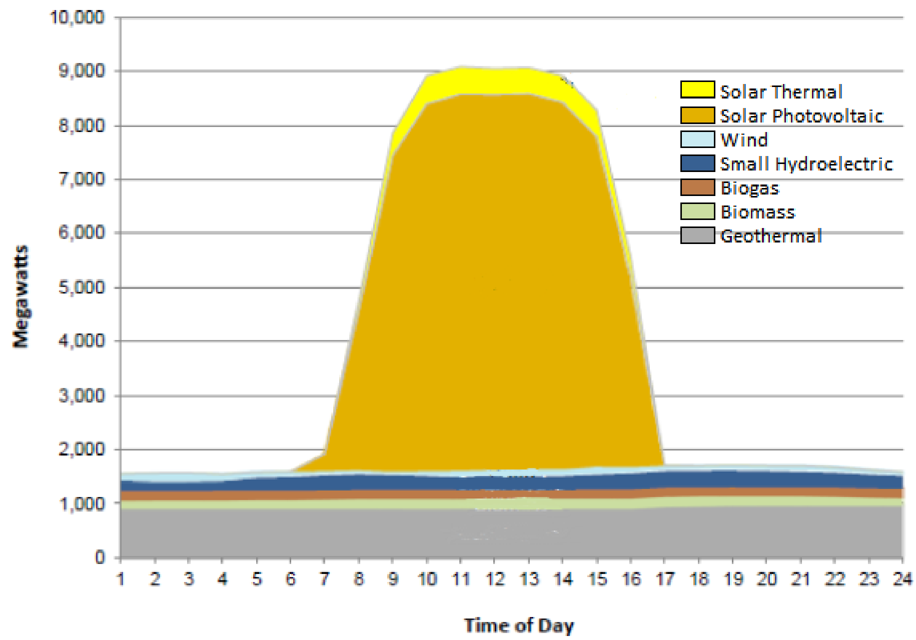
- The variable output from customer-owned solar PV DG results in less predictable demand resulting in load forecasts that are either too high or too low because the variable output modifies the amount of energy that the LSE must provide.
- During hours when solar irradiation at ground level is high, generation from customer-owned solar PV DG reduces overall system demand while at the same time utility-scale solar PV, purchased through PPAs, is likely overproducing relative to its nominal output. This dampened demand/over supply condition drives CAISO pricing downward as supply exceeds demand.
- During hours with less solar irradiation at ground level, less generation from customer-owned PV DG increases overall system demand while at the same time utility-scale solar PV, is likely underproducing relative to its nominal output. This increased demand/reduced supply condition increases overall CAISO pricing as marginally more expensive resources are dispatched to serve this load.

Unfortunately, this variability of renewable generation drives the increasing volatility of the CAISO market prices and this requires more complex CAISO market products to mitigate the volatility. The implication for the City CCA program's energy supply portfolio management will be to 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 exposure to the CAISO market prices.

The CAISO now tracks the amount of statewide renewable resources that contribute to the total electricity needs for participating LSEs in California.[33] This analysis includes renewable resources from all participants and does not include customer-owned DG (which have the effect of reducing demand). Figure E-11 illustrates the mid-day ramping of utility-scale solar resources with other renewable resources continuing to generate throughout the day.

[33] CAISO Renewables Watch: http://www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx

Figure E-11: Replica of CAISO's November 10, 2016 Renewables Watch Renewable Portfolio



The Study assumes that the energy cost forecasts, which are based on current trends, still apply with increasing levels of renewable generation. However, the intermittency of renewable generation resources combined with the variability of solar generation output during daylight hours may make these assumptions change going forward. For example:

- As more solar generation capacity is added to the system, the value of that daytime capacity diminishes.
- When renewable generation, including solar PV, has enough capacity to meet daytime electricity demand, natural gas generation will still be required to be on-line to provide local and system reliability reserve, area frequency and voltage support and to provide additional generation when renewable output is less than expected. While natural gas-fired generation output is low, the resulting effective heat rates are suboptimal and will tend to increase the cost of energy supplied by these natural gas-fired resources. The economic and financial impacts on natural gas-fired generation may result in large shifts from historical pricing patterns and cause additional cost uncertainty for future energy supply portfolios.
- When renewable generation exceeds demand, CAISO prices will be negative (i.e., the CAISO will pay takers of energy) requiring energy storage charging, demand response resources to increase demand, and potentially the curtailment of renewable generation to keep the electricity grid in balance.

Resource Adequacy

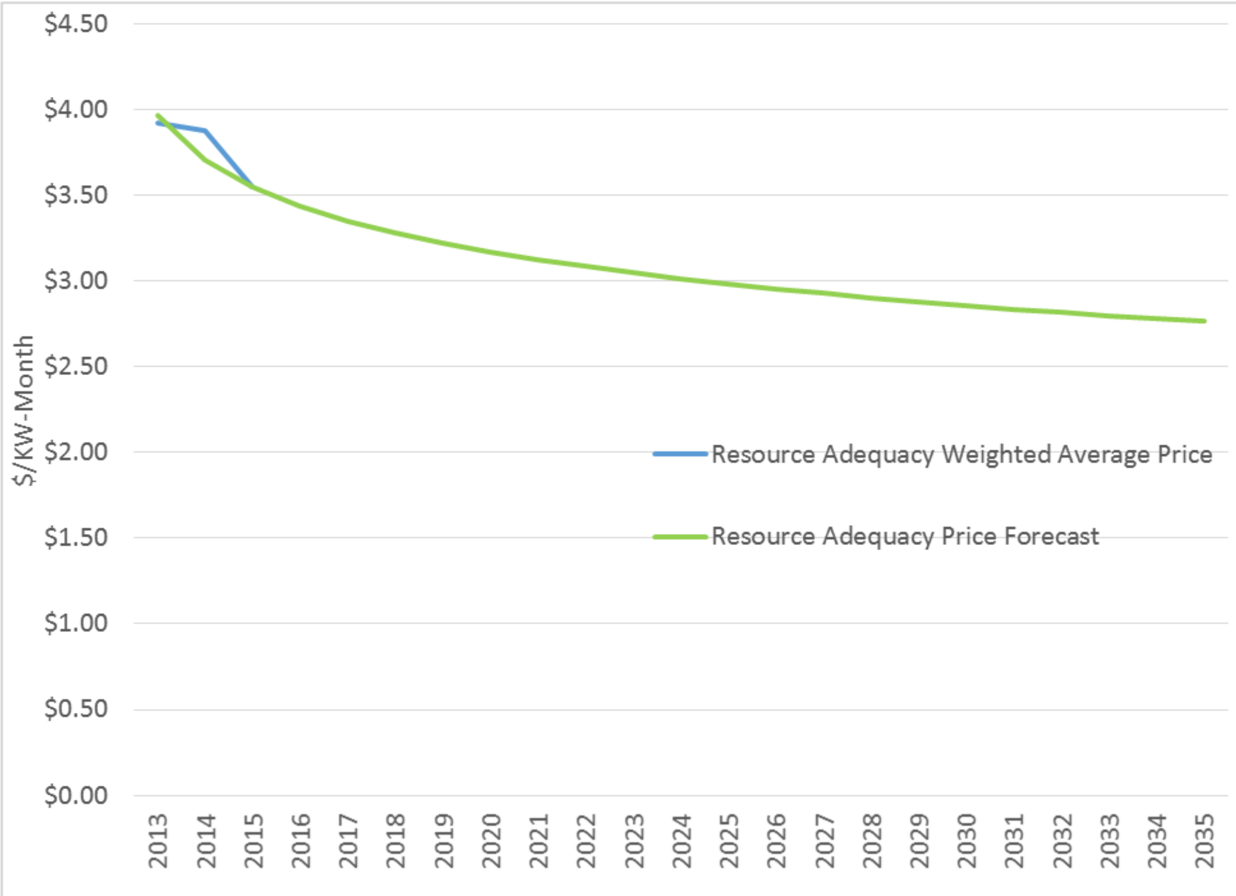
LSEs can procure RA capacity through various processes, but most will require a specific solicitation because currently there is no liquid market for capacity products in California and all RA transactions occur in the bilateral marketplace.[34] The most straightforward approach is the use of the "full requirements load following" type of PPAs that provide all energy (renewable and conventional including base load and shaped load requirements), capacity (system and local RA), distribution losses, uplift and any ancillary charges. LSEs can issue requests for proposals for procurement of RA capacity, soliciting a capacity amount, price, and term from qualified power marketers and/or generation owners, either as stand-alone requests or as part of a larger, more comprehensive procurement initiative. California utilities go through this process annually using a request for offer (RFO) process to procure RA products for their bundled service customers. LSEs can require RA be provided as part of PPAs covering purchased energy and capacity through one solicitation. Most power marketers and all generation owners are potential suppliers of RA products. Because the RA capacity market is illiquid, price discovery is difficult. However, the CPUC's 2013 – 2014 Resource Adequacy Report[35] estimates a range of capacity pricing. Table E-5 shows the Southern California region or South of Path 26 Zone (known as SP-26) pricing from this report.

Table E-5: SP-26 Aggregated RA Contract Prices 2013-1735

SP-26 Aggregated RA Contract Prices 2013-17[35]	$/kW Month
Weighted Average Price	$3.60
Average Price	$3.61
Minimum Price	$0.09
Maximum Price	$26.54
85^{th} Percentile	$8.20

[34] Note that the CPUC is considering a Demand Response Auction Mechanism (DRAM) for demand response resources after bifurcation of Demand Response (DR) resources into "load modifying" and "supply side" DR.
[35] CPUC *2013 – 2014 Resource Adequacy Report, August 2015,* www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6325

Figure E-12: Resource Adequacy Price Forecast



This Study used the historical data from the 2013 – 2014 Resource Adequacy Report to develop the forecasted RA cost used in the Monte Carlo energy supply portfolio cost analysis illustrated in Figure E-12. This decreasing trend in RA cost is consistent with the increase in DG PV. A decade ago, the peak demand and most expensive RA resources were required slightly before the solar PV output peak. As DG PV has increased, this daytime peak capacity requirement has decreased.

MONTE CARLO ENERGY SUPPLY PORTFOLIO COST ANALYSIS

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. The Monte Carlo Simulation Model (MCSM) runs assist these decisions by evaluating the likely load based on statistical probability of occurrence. For purposes of this feasibility Study, the MCSM ran ten simulated 15-year load forecasts to estimate the potential variability in future customer load based on past behavior. The variability of both customer-owned variable generation as well as utility scale bulk renewable generation on the power supply side has also been modeled in the MCSM. These simulations bound the City CCA program's exposure to volatile market prices.

The Monte Carlo energy supply portfolio cost analysis used the load forecast, energy supply portfolio cost estimates and a statistical interpretation of the associated variables to estimate both demand and power supply costs for every hour of every day in the 2020-2035 time horizon of this Study. The following RPC Scenarios were run in the MCSM:

- Base Case Scenario - 50% Renewable Portfolio Content power supply for 98% of CCA customers with the remaining 2% of CCA customers opting up to the 100% Renewable Portfolio Content optional program
- Scenario 2 - 50% Renewable Portfolio Content power supply for all customers
- Scenario 3 - 80% Renewable Portfolio Content power supply for all customers
- Scenario 4 - 100% Renewable Portfolio Content power supply for all customers
- Scenario 5 - 80% Renewable Portfolio Content power supply for 98% of CCA customers with the remaining 2% of CCA customers opting up to the 100% Renewable Portfolio Content optional program

Ten MCSM simulations for each Scenario were run to determine the 95% confidence interval for both usage and energy supply portfolio costs. The following outlines the basic tasks conducted as part of the Monte Carlo energy supply portfolio cost analysis.

- Load Forecast
    - The load analysis used historical hourly usage data to determine the historical average and standard deviation with confidence intervals to inform the expected load and quantity of power needed to be purchased in advance through PPAs.
    - The Study relied on the annual electricity usage for SDG&E's entire service territory from 2001 to 2015, as reported in the U.S. Department of Energy's Energy Information Administration's Form EIA-826,[36] to develop a curve fit forecast of electric energy consumption through 2035. This load forecast was then adjusted for future years to include only bundled customers within the City CCA program's territory.
    - Every hour of every day for the 2020-2035 Study period was then simulated using a normal statistical distribution with the average and standard deviation of demand for any given hour of any given month, with differentiation between weekdays and weekends/holidays.
- Customer Owned DG
    - The simulated days for 2020-2035 then estimate customer Solar PV output with a normal statistical distribution for variable output for any given hour of any given month, with differentiation between weekdays and weekends/holidays.
- Utility-Scale Renewable Generation
    - The actual output from bulk renewable generation is considered variable generation. To simulate this, the output was adjusted randomly relative to expected electricity delivery between -6% and +6% with the average output meeting expectations.
    - When excess bulk renewable generation is provided, the excess is modeled as sold into the CAISO market.
    - When bulk renewable generation provides less energy than expected, additional energy is modeled as being procured from the CAISO market.

[36] DOE Energy Information Agency, Form EIA-826Monthly SDG&E Delivery & Sales 2010-2015: http://www.eia.gov/electricity/data/eia826/

- CAISO Supply Costs
  - CAISO Supply Costs were simulated for the 2020-2035 Study period using day-ahead and real-time LMP pricing from January 2013 through October 2016 combined with a beta distribution constrained by the maximum and minimum market prices encountered for any given hour of any given month, with differentiation between weekdays and weekends/holidays.
- Results for the various renewable portfolio content Scenarios were developed.

50% RENEWABLE PORTFOLIO CONTENT SCENARIO

Table E-6 reflects the 95% confidence interval power procurement costs developed from the ten MCSM runs for the 50% RPC Scenario.

Table E-6: 95% Confidence Interval Procurement Costs for 50% RPC Scenario

Year	Net Simulated Annual MWh	RA $	Natural Gas PPA $	Renewable Energy PPA $	CPUC Day-Ahead $	CPUC Real-Time $	Storage Cost per Year	Total	$ per MWh
2020	7,129,503	$62,818,232	$146,769,569	$317,485,266	$1,804,609	$12,571,731	$1,832,089	$543,281,496	$76
2021	7,098,102	$62,935,459	$138,295,339	$316,068,351	$1,903,095	$13,130,050	$1,693,839	$534,026,134	$75
2022	7,086,700	$63,046,446	$136,120,446	$305,226,331	$1,541,333	$12,398,022	$1,565,905	$519,898,484	$73
2023	7,077,799	$63,151,915	$134,704,909	$308,854,246	$1,829,207	$12,171,631	$1,447,536	$522,159,444	$74
2024	7,084,168	$63,252,454	$127,050,582	$306,974,962	$1,930,975	$12,509,876	$1,338,031	$513,056,880	$72
2025	7,048,318	$63,348,549	$122,648,919	$308,523,420	$1,781,923	$12,070,619	$1,236,740	$509,610,170	$72
2026	7,044,270	$63,440,612	$120,437,828	$298,836,043	$1,798,237	$12,214,744	$1,143,057	$497,870,520	$71
2027	7,038,783	$63,528,992	$118,017,247	$299,335,993	$1,935,875	$12,366,483	$1,056,419	$496,241,008	$71
2028	7,050,206	$63,613,996	$113,897,268	$304,004,208	$1,846,091	$11,842,244	$976,303	$496,180,110	$70
2029	7,026,284	$63,695,886	$110,129,045	$302,456,296	$1,820,032	$12,659,898	$902,226	$491,663,383	$70
2030	7,026,740	$63,774,897	$106,951,693	$301,659,656	$1,870,970	$12,762,843	$833,737	$487,853,795	$69
2031	7,024,550	$63,851,234	$103,162,930	$294,832,146	$1,800,228	$11,891,459	$770,419	$476,308,415	$68
2032	7,048,259	$63,925,082	$102,895,509	$293,790,454	$1,747,557	$12,943,428	$711,885	$476,013,915	$68
2033	7,040,691	$63,996,604	$99,792,289	$299,500,554	$1,887,195	$12,398,799	$657,778	$478,233,219	$68
2034	7,047,360	$64,065,950	$98,321,589	$290,779,404	$1,968,940	$12,356,425	$607,764	$468,100,073	$66
2035	7,050,004	$64,133,254	$96,194,791	$291,866,047	$1,725,923	$11,662,946	$561,538	$466,144,498	$66

Tables E-7 through E-12 provide the range of simulated power procurement results for the 50% RPC Scenario that fed into the procurement costs that were displayed in Table E-6. The minimum, average, and maximum columns provide the range and mean of the Monte Carlo results from 10 simulation runs. The 95% CI column takes the variation from those 10 runs, and prescribes the upper end of a 95% confidence interval. That is, there is a 95% probability that expected costs will be less than the 95% CI value.

Table E-7: Range of Simulated Annual Natural Gas Generation Procurement Costs

Year	Minimum Natural Gas PPA $	Average Natural Gas PPA $	95% CI Natural Gas PPA $	Maximum Natural Gas PPA $
2020	$115,771,809	$137,793,485	$146,769,569	$161,879,546
2021	$102,296,057	$128,766,572	$138,295,339	$151,321,540
2022	$104,465,657	$126,794,685	$136,120,446	$152,134,806
2023	$95,436,062	$124,242,917	$134,704,909	$149,411,255
2024	$95,973,182	$118,452,444	$127,050,582	$140,601,901
2025	$87,543,057	$112,129,038	$122,648,919	$140,556,885
2026	$85,555,144	$110,439,157	$120,437,828	$135,904,214
2027	$84,079,020	$108,787,735	$118,017,247	$131,561,710
2028	$82,360,651	$105,214,111	$113,897,268	$126,660,820
2029	$76,767,483	$100,412,643	$110,129,045	$127,988,938
2030	$68,776,599	$96,584,939	$106,951,693	$126,201,069
2031	$65,015,853	$92,983,125	$103,162,930	$117,204,621
2032	$71,122,240	$93,763,698	$102,895,509	$115,849,538
2033	$62,530,653	$89,538,866	$99,792,289	$114,403,696
2034	$63,933,714	$88,637,631	$98,321,589	$113,320,193
2035	$60,336,327	$86,080,309	$96,194,791	$111,355,990

Table E-8: Range of Simulated Annual 50% Renewable Portfolio Content Generation Procurement Costs

Year	Minimum RPC PPA $	Average RPC PPA $	95% CI RPC PPA $	Maximum RPC PPA $
2020	$227,259,645	$293,531,944	$317,485,266	$354,204,321
2021	$232,953,462	$292,750,204	$316,068,351	$351,703,571
2022	$233,465,108	$284,821,809	$305,226,331	$338,181,427
2023	$241,112,467	$290,094,848	$308,854,246	$335,261,463
2024	$239,959,372	$287,366,065	$306,974,962	$340,583,452
2025	$243,936,483	$288,945,789	$308,523,420	$343,162,030
2026	$241,959,301	$281,319,527	$298,836,043	$334,348,617
2027	$234,118,806	$280,945,149	$299,335,993	$325,115,409

Year	Minimum RPC PPA $	Average RPC PPA $	95% CI RPC PPA $	Maximum RPC PPA $
2028	$239,995,337	$287,060,167	$304,004,208	$328,284,622
2029	$245,671,514	$287,104,107	$302,456,296	$326,534,443
2030	$234,919,468	$283,732,914	$301,659,656	$328,949,907
2031	$245,095,501	$280,582,208	$294,832,146	$314,192,618
2032	$244,323,469	$279,781,576	$293,790,454	$316,381,377
2033	$252,731,571	$285,986,718	$299,500,554	$323,077,571
2034	$250,376,814	$279,454,899	$290,779,404	$304,701,083
2035	$252,103,606	$280,532,622	$291,866,047	$311,885,183

Table E-9: Range of Simulated Annual CAISO Day-Ahead Market Procurement Costs

Year	Minimum CPUC Day-Ahead $	Average CPUC Day-Ahead $	95% CI CPUC Day-Ahead $	Maximum CPUC Day-Ahead $
2020	-$1,612,526	$922,094	$1,804,609	$2,852,253
2021	-$1,173,914	$1,065,591	$1,903,095	$3,158,766
2022	-$1,368,274	$734,901	$1,541,333	$2,720,405
2023	-$1,029,270	$1,056,511	$1,829,207	$3,031,909
2024	-$2,325,442	$862,272	$1,930,975	$3,506,164
2025	-$1,303,131	$934,251	$1,781,923	$3,363,036
2026	-$1,336,071	$908,196	$1,798,237	$3,138,924
2027	-$1,087,950	$1,098,043	$1,935,875	$3,426,908
2028	-$884,481	$1,035,063	$1,846,091	$3,121,345
2029	-$1,082,446	$952,398	$1,820,032	$3,161,237
2030	-$1,015,524	$1,060,536	$1,870,970	$2,921,772
2031	-$1,193,871	$975,589	$1,800,228	$2,898,998
2032	-$1,562,406	$878,904	$1,747,557	$3,114,965
2033	-$1,151,512	$1,006,452	$1,887,195	$3,339,670
2034	-$1,295,099	$1,067,647	$1,968,940	$3,467,311
2035	-$1,236,078	$873,262	$1,725,923	$3,123,977

Table E-10: Range of Simulated Annual CAISO Real-Time Market Procurement Costs

Year	Minimum CPUC Real-Time $	Average CPUC Real-Time $	95% CI CPUC Real-Time $	Maximum CPUC Real-Time $
2020	$6,271,216	$10,755,604	$12,571,731	$15,510,329
2021	$6,684,189	$11,077,374	$13,130,050	$17,045,334
2022	$6,005,053	$10,499,011	$12,398,022	$15,259,649
2023	$4,912,558	$10,172,544	$12,171,631	$15,164,439
2024	$5,984,957	$10,569,991	$12,509,876	$15,961,060
2025	$6,253,521	$10,518,918	$12,070,619	$14,023,423
2026	$5,492,464	$10,436,608	$12,214,744	$14,516,937
2027	$5,958,669	$10,469,487	$12,366,483	$15,340,129
2028	$5,285,024	$9,941,517	$11,842,244	$15,217,005
2029	$6,472,486	$10,848,708	$12,659,898	$15,972,715
2030	$5,978,789	$10,847,267	$12,762,843	$15,670,081
2031	$5,718,637	$9,955,816	$11,891,459	$15,094,496
2032	$6,550,740	$11,041,442	$12,943,428	$15,888,624
2033	$6,243,655	$10,634,143	$12,398,799	$14,817,535
2034	$6,612,913	$10,577,986	$12,356,425	$15,438,506
2035	$6,049,012	$9,985,330	$11,662,946	$14,700,336

Table E-11: Range of Simulated Total Power Supply Portfolio Procurement Costs

Year	Minimum $	Average $	95% CI $	Maximum $
2020	$412,340,465	$507,653,449	$543,281,496	$599,096,771
2021	$405,389,093	$498,289,041	$534,026,134	$587,858,510
2022	$407,179,895	$487,462,756	$519,898,484	$572,908,638
2023	$405,031,268	$490,166,271	$522,159,444	$567,468,517
2024	$404,182,555	$481,841,256	$513,056,880	$565,243,062
2025	$401,015,220	$477,113,285	$509,610,170	$565,690,663
2026	$396,254,506	$467,687,155	$497,870,520	$552,492,361
2027	$387,653,957	$465,885,825	$496,241,008	$540,029,567

Year	Minimum $	Average $	95% CI $	Maximum $
2028	$391,346,831	$467,841,158	$496,180,110	$537,874,091
2029	$392,427,149	$463,915,969	$491,663,383	$538,255,446
2030	$373,267,965	$456,834,289	$487,853,795	$538,351,462
2031	$379,257,774	$449,118,390	$476,308,415	$514,012,387
2032	$385,071,009	$450,102,586	$476,013,915	$515,871,471
2033	$385,008,750	$451,820,561	$478,233,219	$520,292,854
2034	$384,302,056	$444,411,877	$468,100,073	$501,600,807
2035	$381,947,659	$442,166,315	$466,144,498	$505,760,277

Table E-12: Range of Simulated Total Power Supply Portfolio Procurement Cost per MW

Year	Minimum $/MW	Average $/MW	95% CI $/MW	Maximum $/MW
2020	$58	$71	$76	$84
2021	$58	$70	$75	$82
2022	$58	$69	$73	$80
2023	$58	$69	$74	$80
2024	$57	$68	$72	$80
2025	$57	$68	$72	$80
2026	$57	$66	$71	$78
2027	$55	$66	$70	$76
2028	$56	$66	$70	$76
2029	$56	$66	$70	$76
2030	$53	$65	$69	$76
2031	$54	$64	$68	$73
2032	$55	$64	$67	$73
2033	$55	$64	$68	$74
2034	$55	$63	$66	$71
2035	$54	$63	$66	$71

80% RPC PORTFOLIO

Table E-13 reflects the 95% confidence interval power procurement costs developed from the ten MCSM runs for the 80% RPC Scenario.

Table E-13: 95% Confidence Interval Procurement Costs for 80% RPC Scenario

Year	Net Simulated Year MWh	RA $	Natural Gas PPA $	Renewable Energy PPA $	CPUC Day-Ahead $	CPUC Real-Time $	Storage Cost per Year	Total	$/MWh
2020	7,128,330	$62,818,232	$58,070,733	$489,798,522	$2,314,542	$12,218,657	$1,832,089	$627,052,776	$88
2021	7,098,521	$62,935,459	$56,404,152	$502,565,975	$2,335,611	$12,149,567	$1,693,839	$638,084,603	$90
2022	7,085,116	$63,046,446	$54,004,333	$483,376,155	$1,559,109	$12,028,645	$1,565,905	$615,580,593	$87
2023	7,070,817	$63,151,915	$52,844,641	$499,319,008	$1,830,566	$12,626,786	$1,447,536	$631,220,452	$89
2024	7,086,089	$63,252,454	$50,904,845	$486,192,871	$2,233,936	$11,601,061	$1,338,031	$615,523,197	$87
2025	7,056,087	$63,348,549	$49,316,867	$478,022,792	$2,310,330	$12,672,818	$1,236,740	$606,908,096	$86
2026	7,045,391	$63,440,612	$49,844,067	$493,660,420	$2,308,730	$11,903,081	$1,143,057	$622,299,966	$88
2027	7,039,675	$63,528,992	$47,198,449	$478,633,318	$1,852,131	$12,447,754	$1,056,419	$604,717,063	$86
2028	7,049,704	$63,613,996	$45,400,093	$477,062,081	$2,039,809	$12,573,649	$976,303	$601,665,931	$85
2029	7,024,250	$63,695,886	$43,395,756	$482,026,435	$2,021,376	$12,182,303	$902,226	$604,223,981	$86
2030	7,028,249	$63,774,897	$42,276,682	$481,661,420	$2,053,056	$12,547,596	$833,737	$603,147,388	$86
2031	7,025,125	$63,851,234	$42,788,449	$474,181,009	$2,018,721	$12,180,844	$770,419	$595,790,675	$85
2032	7,052,958	$63,925,082	$42,360,314	$469,774,303	$1,887,472	$12,349,889	$711,885	$591,008,945	$84
2033	7,039,085	$63,996,604	$40,425,042	$473,766,975	$2,136,748	$12,302,857	$657,778	$593,286,003	$84
2034	7,043,127	$64,065,950	$37,631,534	$464,303,478	$2,166,721	$12,560,494	$607,764	$581,335,941	$83
2035	7,052,847	$64,133,254	$38,764,346	$467,169,436	$2,392,591	$12,664,807	$561,538	$585,685,972	$83

Tables E-14 through Table E-19 provide the range of simulated power procurement results for the 80% RPC Scenario that fed into the procurement costs that were displayed in Table E-13.

Table E-14: Range of Simulated Annual Natural Gas Generation Procurement Costs

Year	Minimum Natural Gas PPA $	Average Natural Gas PPA $	95% CI Natural Gas PPA $	Maximum Natural Gas PPA $
2020	$45,046,795	$54,478,302	$58,070,733	$63,137,961
2021	$42,461,728	$52,331,357	$56,404,152	$63,496,765
2022	$39,082,362	$49,998,553	$54,004,333	$60,436,169
2023	$40,394,245	$49,285,300	$52,844,641	$58,360,115
2024	$36,013,608	$46,689,649	$50,904,845	$57,730,932
2025	$36,215,517	$45,522,455	$49,316,867	$55,393,614
2026	$33,958,488	$45,471,947	$49,844,067	$56,166,062

2027	$33,968,177	$43,318,840	$47,198,449	$54,128,715
2028	$32,324,362	$41,642,363	$45,400,093	$51,194,353
2029	$30,232,564	$39,539,328	$43,395,756	$49,861,702
2030	$27,463,363	$38,088,266	$42,276,682	$48,575,183
2031	$29,809,653	$38,952,855	$42,788,449	$49,609,504
2032	$28,284,040	$38,515,408	$42,360,314	$48,778,844
2033	$26,892,236	$36,466,455	$40,425,042	$46,930,332
2034	$26,908,379	$34,613,673	$37,631,534	$41,826,537
2035	$23,719,501	$34,445,385	$38,764,346	$46,054,096

Table E-15: Range of Simulated Annual 80% Renewable Portfolio Content Generation Procurement Costs

Year	Minimum RPC PPA $	Average RPC PPA $	95% CI RPC PPA $	Maximum RPC PPA $
2020	$376,836,614	$455,682,724	$489,798,522	$544,570,854
2021	$376,892,797	$467,399,094	$502,565,975	$554,910,459
2022	$374,954,852	$452,271,028	$483,376,155	$529,770,273
2023	$380,057,826	$465,881,271	$499,319,008	$549,874,026
2024	$358,946,175	$451,967,054	$486,192,871	$534,958,514
2025	$393,208,693	$453,279,341	$478,022,792	$522,630,024
2026	$379,542,577	$460,653,360	$493,660,420	$547,329,124
2027	$380,407,049	$450,357,833	$478,633,318	$527,725,918
2028	$380,368,873	$450,007,380	$477,062,081	$513,726,334
2029	$383,987,141	$455,244,189	$482,026,435	$523,430,991
2030	$406,823,031	$460,633,661	$481,661,420	$511,634,819
2031	$389,151,597	$451,945,080	$474,181,009	$503,346,103
2032	$390,881,691	$447,253,952	$469,774,303	$503,514,988
2033	$395,541,414	$454,048,498	$473,766,975	$498,438,265
2034	$381,684,938	$442,792,701	$464,303,478	$499,142,135
2035	$412,170,755	$451,599,570	$467,169,436	$491,777,113

Table E-16: Range of Simulated Annual CAISO Day-Ahead Market Procurement Costs

Year	Minimum CPUC Day-Ahead $	Average CPUC Day-Ahead $	95% CI CPUC Day-Ahead $	Maximum CPUC Day-Ahead $
2020	-$2,367,790	$1,056,079	$2,314,542	$3,986,458
2021	-$1,139,724	$1,292,986	$2,335,611	$3,837,049
2022	-$2,188,874	$538,339	$1,559,109	$3,002,234
2023	-$1,555,795	$883,558	$1,830,566	$3,531,565
2024	-$1,180,612	$1,215,390	$2,233,936	$3,960,447
2025	-$1,879,300	$1,153,256	$2,310,330	$4,221,537
2026	-$1,991,373	$1,222,011	$2,308,730	$3,813,062
2027	-$2,340,431	$745,797	$1,852,131	$3,504,130
2028	-$2,539,443	$782,296	$2,039,809	$4,463,246
2029	-$1,500,382	$944,935	$2,021,376	$3,679,112
2030	-$1,954,709	$938,574	$2,053,056	$3,713,216
2031	-$1,884,504	$917,674	$2,018,721	$4,006,370
2032	-$2,505,706	$737,660	$1,887,472	$3,499,841
2033	-$1,852,784	$1,023,292	$2,136,748	$3,754,803
2034	-$2,135,002	$1,034,041	$2,166,721	$3,914,370
2035	-$2,202,938	$1,158,341	$2,392,591	$4,052,750

Table E-17: Range of Simulated Annual CAISO Real-Time Market Procurement Costs

Year	Minimum CPUC Real-Time $	Average CPUC Real-Time $	95% CI CPUC Real-Time $	Maximum CPUC Real-Time $
2020	$5,952,932	$10,446,517	$12,218,657	$14,968,282
2021	$5,087,024	$10,283,668	$12,149,567	$14,814,585
2022	$6,137,566	$10,378,521	$12,028,645	$14,759,699
2023	$5,758,427	$10,725,714	$12,626,786	$15,720,910
2024	$6,211,807	$9,957,150	$11,601,061	$14,689,697
2025	$5,822,117	$10,730,100	$12,672,818	$15,942,103
2026	$5,792,849	$10,177,426	$11,903,081	$14,796,725

Year	Minimum CPUC Real-Time $	Average CPUC Real-Time $	95% CI CPUC Real-Time $	Maximum CPUC Real-Time $
2027	$6,567,527	$10,725,706	$12,447,754	$15,485,036
2028	$6,254,272	$10,837,525	$12,573,649	$15,378,537
2029	$6,287,301	$10,511,314	$12,182,303	$14,798,010
2030	$5,960,032	$10,599,585	$12,547,596	$15,439,354
2031	$5,273,989	$10,270,010	$12,180,844	$14,802,762
2032	$4,826,806	$10,413,639	$12,349,889	$14,535,377
2033	$5,562,341	$10,288,026	$12,302,857	$16,247,160
2034	$6,812,533	$10,801,972	$12,560,494	$15,630,588
2035	$5,381,229	$10,754,414	$12,664,807	$15,230,405

Table E-18: Range of Simulated Total Power Supply Portfolio Procurement Costs

Year	Minimum $	Average $	95% CI $	Maximum $
2020	$490,118,873	$586,313,943	$627,052,776	$691,313,876
2021	$487,931,124	$595,936,404	$638,084,603	$701,688,157
2022	$482,598,259	$577,798,793	$615,580,593	$672,580,727
2023	$489,254,154	$591,375,294	$631,220,452	$692,086,067
2024	$464,581,463	$574,419,727	$615,523,197	$675,930,075
2025	$497,952,316	$575,270,442	$606,908,096	$662,772,568
2026	$481,886,210	$582,108,411	$622,299,966	$686,688,641
2027	$483,187,734	$569,733,588	$604,717,063	$665,429,211
2028	$480,998,363	$567,859,863	$601,665,931	$649,352,770
2029	$483,604,735	$570,837,878	$604,223,981	$656,367,927
2030	$502,900,350	$574,868,719	$603,147,388	$643,971,206
2031	$486,972,388	$566,707,272	$595,790,675	$636,386,392
2032	$486,123,797	$561,557,626	$591,008,945	$634,966,017
2033	$490,797,589	$566,480,653	$593,286,003	$630,024,942
2034	$477,944,563	$553,916,102	$581,335,941	$625,187,344
2035	$503,763,340	$562,652,501	$585,685,972	$621,809,156

Table E-19: Range of Simulated Total Power Supply Portfolio Procurement Cost per MW

Year	Minimum $/MW	Average $/MW	95% CI $/MW	Maximum $/MW
2020	$69	$82	$88	$97
2021	$69	$84	$90	$98
2022	$68	$82	$87	$95
2023	$70	$84	$89	$97
2024	$66	$81	$87	$95
2025	$71	$82	$86	$94
2026	$69	$83	$88	$97
2027	$69	$81	$86	$94
2028	$69	$81	$85	$92
2029	$69	$81	$86	$93
2030	$72	$82	$86	$91
2031	$70	$81	$85	$90
2032	$70	$80	$84	$90
2033	$70	$81	$84	$89
2034	$68	$79	$82	$89
2035	$72	$80	$83	$88

100% RPC SCENARIO

Table E-20 reflects the 95% confidence interval power procurement costs developed from the ten MCSM runs for the 100% RPC Scenario.

Table E-20: 95% Confidence Interval Procurement Costs for 100% Renewable Portfolio

Year	Net Simulated Year MWh	RA $	Natural Gas PPA $	Renewable Energy PPA $	CPUC Day-Ahead $	CPUC Real-Time $	Storage Cost per Year	Total	$ per MWh
2020	7,133,002	$62,818,232	$0	$635,828,606	$2,637,326	$12,144,898	$1,832,089	$715,261,151	$100
2021	7,099,059	$62,935,459	$0	$619,266,835	$1,893,070	$12,678,607	$1,693,839	$698,467,810	$98
2022	7,088,618	$63,046,446	$0	$612,831,498	$1,886,305	$12,712,266	$1,565,905	$692,042,420	$98
2023	7,071,967	$63,151,915	$0	$613,790,674	$1,937,310	$12,426,115	$1,447,536	$692,753,550	$98
2024	7,082,508	$63,252,454	$0	$608,310,013	$2,231,580	$12,701,792	$1,338,031	$687,833,870	$97
2025	7,053,247	$63,348,549	$0	$607,437,492	$2,489,952	$12,360,777	$1,236,740	$686,873,510	$97

2026	7,041,496	$63,440,612	$0	$612,570,055	$1,745,012	$12,732,216	$1,143,057	$691,630,952	$98
2027	7,035,466	$63,528,992	$0	$600,131,113	$2,100,848	$12,313,337	$1,056,419	$679,130,708	$97
2028	7,048,318	$63,613,996	$0	$595,875,723	$2,317,174	$12,746,072	$976,303	$675,529,268	$96
2029	7,024,550	$63,695,886	$0	$595,091,563	$2,332,556	$12,311,563	$902,226	$674,333,795	$96
2030	7,026,580	$63,774,897	$0	$596,579,556	$2,085,998	$12,352,384	$833,737	$675,626,572	$96
2031	7,027,944	$63,851,234	$0	$601,985,018	$2,426,229	$12,196,747	$770,419	$681,229,647	$97
2032	7,050,873	$63,925,082	$0	$596,442,910	$2,245,995	$12,883,710	$711,885	$676,209,582	$96
2033	7,034,458	$63,996,604	$0	$590,143,067	$1,875,675	$12,524,470	$657,778	$669,197,594	$95
2034	7,043,236	$64,065,950	$0	$593,095,641	$2,741,000	$12,211,807	$607,764	$672,722,163	$96
2035	7,052,563	$64,133,254	$0	$579,629,278	$2,381,154	$12,046,542	$561,538	$658,751,765	$93

Tables E-21 through E-25 provide the range of simulated power procurement results for the 100% RPC Scenario that fed into the procurement costs that were displayed in Table E-20.

Table E-21: Range of Simulated Annual 100% Renewable Portfolio Content Generation Procurement Costs

Year	Minimum RPC PPA $	Average RPC PPA $	95% CI RPC PPA $	Maximum RPC PPA $
2020	$458,931,120	$585,135,327	$635,828,606	$702,180,313
2021	$472,365,839	$577,477,212	$619,266,835	$687,305,485
2022	$454,161,574	$573,107,162	$612,831,498	$663,473,962
2023	$454,847,030	$568,815,621	$613,790,674	$685,101,013
2024	$465,783,453	$569,851,422	$608,310,013	$657,907,504
2025	$482,783,904	$568,153,831	$607,437,492	$667,442,261
2026	$475,699,440	$574,489,687	$612,570,055	$670,067,369
2027	$487,261,774	$565,431,804	$600,131,113	$657,916,383
2028	$477,311,092	$563,110,932	$595,875,723	$650,363,933
2029	$479,013,583	$563,352,308	$595,091,563	$646,864,632
2030	$502,379,818	$569,315,139	$596,579,556	$633,846,412
2031	$494,624,379	$570,592,286	$601,985,018	$656,440,858
2032	$498,915,111	$568,217,735	$596,442,910	$641,250,724
2033	$497,595,965	$562,346,921	$590,143,067	$631,174,619
2034	$506,970,523	$568,656,032	$593,095,641	$633,410,640
2035	$502,132,630	$557,336,078	$579,629,278	$616,929,574

Table E-22: Range of Simulated Annual CAISO Day-Ahead Market Procurement Costs

Year	Minimum CPUC Day-Ahead $	Average CPUC Day-Ahead $	95% CI CPUC Day-Ahead $	Maximum CPUC Day-Ahead $
2020	-$2,557,200	$1,200,407	$2,637,326	$4,787,441
2021	-$2,630,560	$626,530	$1,893,070	$3,919,417
2022	-$2,405,078	$634,227	$1,886,305	$3,717,676
2023	-$2,395,078	$685,875	$1,937,310	$3,806,540
2024	-$3,146,997	$851,436	$2,231,580	$4,337,777
2025	-$2,256,977	$1,138,709	$2,489,952	$4,436,448
2026	-$1,801,619	$791,309	$1,745,012	$3,141,506
2027	-$2,531,890	$812,959	$2,100,848	$3,960,242
2028	-$1,464,396	$1,144,926	$2,317,174	$4,216,750
2029	-$2,062,055	$1,075,234	$2,332,556	$4,549,882
2030	-$2,097,002	$864,484	$2,085,998	$3,724,981
2031	-$2,252,081	$1,004,346	$2,426,229	$4,829,575
2032	-$2,283,480	$992,193	$2,245,995	$4,176,765
2033	-$2,439,861	$661,785	$1,875,675	$3,695,942
2034	-$2,835,169	$1,326,187	$2,741,000	$4,693,523
2035	-$2,244,261	$1,164,675	$2,381,154	$4,190,481

Table E-23: Range of Simulated Annual CAISO Real-Time Market Procurement Costs

Year	Minimum CPUC Real-Time $	Average CPUC Real-Time $	95% CI CPUC Real-Time $	Maximum CPUC Real-Time $
2020	$5,453,620	$10,333,347	$12,144,898	$14,651,239
2021	$6,572,531	$10,854,173	$12,678,607	$15,956,763
2022	$4,943,423	$10,693,968	$12,712,266	$16,051,849
2023	$5,267,488	$10,515,067	$12,426,115	$15,003,102
2024	$5,893,529	$10,652,315	$12,701,792	$16,300,576
2025	$5,395,608	$10,439,699	$12,360,777	$15,432,713
2026	$7,089,580	$11,064,617	$12,732,216	$15,469,777

Year	Minimum CPUC Real-Time $	Average CPUC Real-Time $	95% CI CPUC Real-Time $	Maximum CPUC Real-Time $
2027	$5,944,501	$10,612,469	$12,313,337	$14,975,310
2028	$6,393,367	$10,815,702	$12,746,072	$16,160,657
2029	$5,396,936	$10,225,272	$12,311,563	$16,531,328
2030	$5,706,633	$10,530,595	$12,352,384	$15,159,494
2031	$4,800,185	$10,037,962	$12,196,747	$15,732,261
2032	$5,450,509	$10,816,793	$12,883,710	$16,176,592
2033	$5,477,304	$10,553,189	$12,524,470	$15,516,026
2034	$5,145,294	$10,421,204	$12,211,807	$14,995,876
2035	$5,712,913	$10,412,006	$12,046,542	$14,532,348

Table E-24: Range of Simulated Total Power Supply Portfolio Procurement Costs

Year	Minimum $	Average $	95% CI $	Maximum $
2020	$526,477,861	$661,319,403	$715,261,151	$786,269,314
2021	$540,937,108	$653,587,214	$698,467,810	$771,810,963
2022	$521,312,271	$649,047,708	$692,042,420	$747,855,839
2023	$522,318,890	$644,616,014	$692,753,550	$768,510,107
2024	$533,120,471	$645,945,658	$687,833,870	$743,136,343
2025	$550,507,824	$644,317,528	$686,873,510	$751,896,711
2026	$545,571,068	$650,929,280	$691,630,952	$753,262,320
2027	$555,259,796	$641,442,643	$679,130,708	$741,437,346
2028	$546,830,362	$639,661,859	$675,529,268	$735,331,639
2029	$546,946,575	$639,250,926	$674,333,795	$732,543,954
2030	$570,598,083	$645,318,851	$675,626,572	$717,339,521
2031	$561,794,136	$646,256,247	$681,229,647	$741,624,346
2032	$566,719,107	$644,663,687	$676,209,582	$726,241,048
2033	$565,287,791	$638,216,278	$669,197,594	$715,040,968
2034	$573,954,362	$645,077,138	$672,722,163	$717,773,755
2035	$570,296,073	$633,607,551	$658,751,765	$700,347,194

Table E-25: Range of Simulated Total Power Supply Portfolio Procurement Cost per MW

Year	Minimum $/MW	Average $/MW	95% CI $/MW	Maximum $/MW
2020	$74	$93	$100	$110
2021	$77	$92	$98	$108
2022	$74	$92	$98	$105
2023	$74	$91	$98	$108
2024	$76	$91	$97	$104
2025	$79	$91	$97	$106
2026	$78	$93	$98	$107
2027	$79	$91	$96	$105
2028	$78	$91	$96	$104
2029	$78	$91	$96	$104
2030	$82	$92	$96	$102
2031	$80	$92	$97	$105
2032	$81	$91	$96	$103
2033	$81	$91	$95	$101
2034	$82	$92	$95	$102
2035	$81	$90	$93	$99

ENERGY SUPPLY PORTFOLIO COST SUMMARY

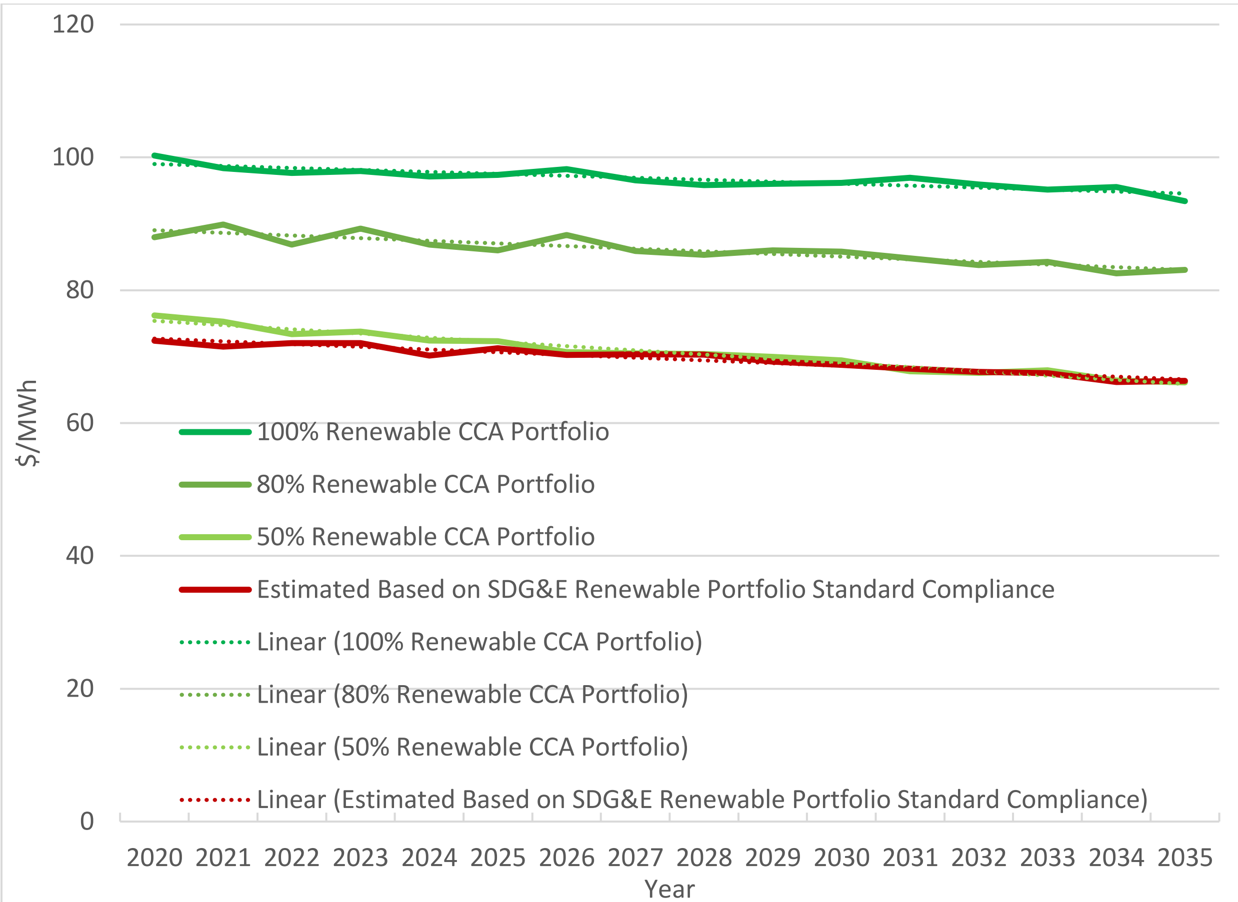
This Study utilized the 95% CI cost estimates from the Monte Carlo simulations which provides an estimate that has a statistical 95% probability of being at or below the CI estimate. However, the maximum simulated cost of supply identified in the tables for each RPC Scenario are an average of 9% higher than the 95% CI number. Therefore, the next step to determine whether a CCA is financially feasible is to issue a Request for Information (RFI) to power suppliers to validate the assumptions as well as the cost of power results described herein.

To better understand how the CCA energy supply portfolio costs compare with the incumbent IOU costs, a cost of power estimate aligning with the forecasted SDG&E RPC is compared to the CCA cost of power for the 50%, 80% and 100% CCA RPC Scenarios, as illustrated in Figure E-13.

The assumed SDG&E energy supply cost uses the same Monte Carlo simulation methodology as was utilized for the CCA RPC Scenarios. While actual SDG&E energy supply costs are likely different than what is depicted, for comparative purposes the Monte Carlo simulation uses the SDG&E progression of contracted RPS-generation amounts[37] through 2020 and assuming compliance with the 2030 goal of 50% RPC.

The peaks and troughs in power supply costs each year is due to the simulation results where customer usage and cost of power vary per the methodology described earlier. Therefore, we have included the dotted linear lines to indicate a smoothed linear trend in power supply costs between the various RPC Scenarios for the City CCA program and SDG&E.

Figure E-13: Cost of Power Comparison 2020-2035



[37] CPUC RPS Home Page - Renewable Procurement Status Percentages show SDG&E's RPS eligible resource mix to be: 31.6% RPS in 2014, 35.2% RPS in 2015 and 45.2% RPS in 2020: http://www.cpuc.ca.gov/RPS_Homepage/

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APPENDIX F

CARBON DIOXIDE EMISSIONS DEVELOPMENT

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APPENDIX F

CARBON DIOXIDE EMISSIONS DEVELOPMENT

Appendix F provides the methodology and assumptions used to develop the estimates of carbon dioxide (CO_2) emissions by Scenario.

This section discusses the current trends in national and California-specific generation emissions. These trends are important as they provide the context for pursuing a higher renewable portfolio content (RPC) for energy supplied to the City CCA Program. While the cost of renewable generation has been decreasing over the last decade, so has the cost of the primary fuel source (natural gas) used to produce the majority of electric energy in California. In addition, the state of California's RPS is driving lower greenhouse gas emissions. SDG&E is currently exceeding the California RPS requirements. Therefore, the greenhouse gas considerations for pursuing a higher RPC via the City CCA program must be weighed against the projections based on current and developing trends (or the "as-is" case).

The environmental analysis established within this Study assesses greenhouse gas emissions under a multitude of different future scenarios, including varying IOU generation portfolios. The analysis began by analyzing the emissions impact of natural gas generation on a per MWh basis. Then, the proportion of demand served by natural gas was altered to understand the impact of the different levels of renewable generation within the RPC Scenarios.

The generation and emissions resulting from the CAISO market is not considered in this analysis. Rather, the simple assumption was made that each MWh that is not served by renewable generation is served by natural gas. This is not a perfect analysis for a variety of reasons, including that it does not consider hydroelectric or nuclear production, nor does it consider the efficiency of natural gas generation under different operating circumstances (always-on vs. only at peak periods). However, these figures are intended to provide an indicative approximation of GHG impact for decision makers.

Utilizing available state or multiple-state level emissions data, such as EPA's eGRID data, is not ideal for this type of analysis as those data sets 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 figure. The average emissions factor may or may not align with utility-specific supply portfolios given the performance of various plants operating. Furthermore, this data lends little insight into the effects of increasing renewable generation content. Because of these issues, the analysis was conducted to compare environmental impacts based on natural gas generation emission factors. This approach allows for an apples-to-apples comparison of the different CCA RPC Scenarios and SDG&E RPS scenarios.

ZERO GHG EMISSIONS GENERATION

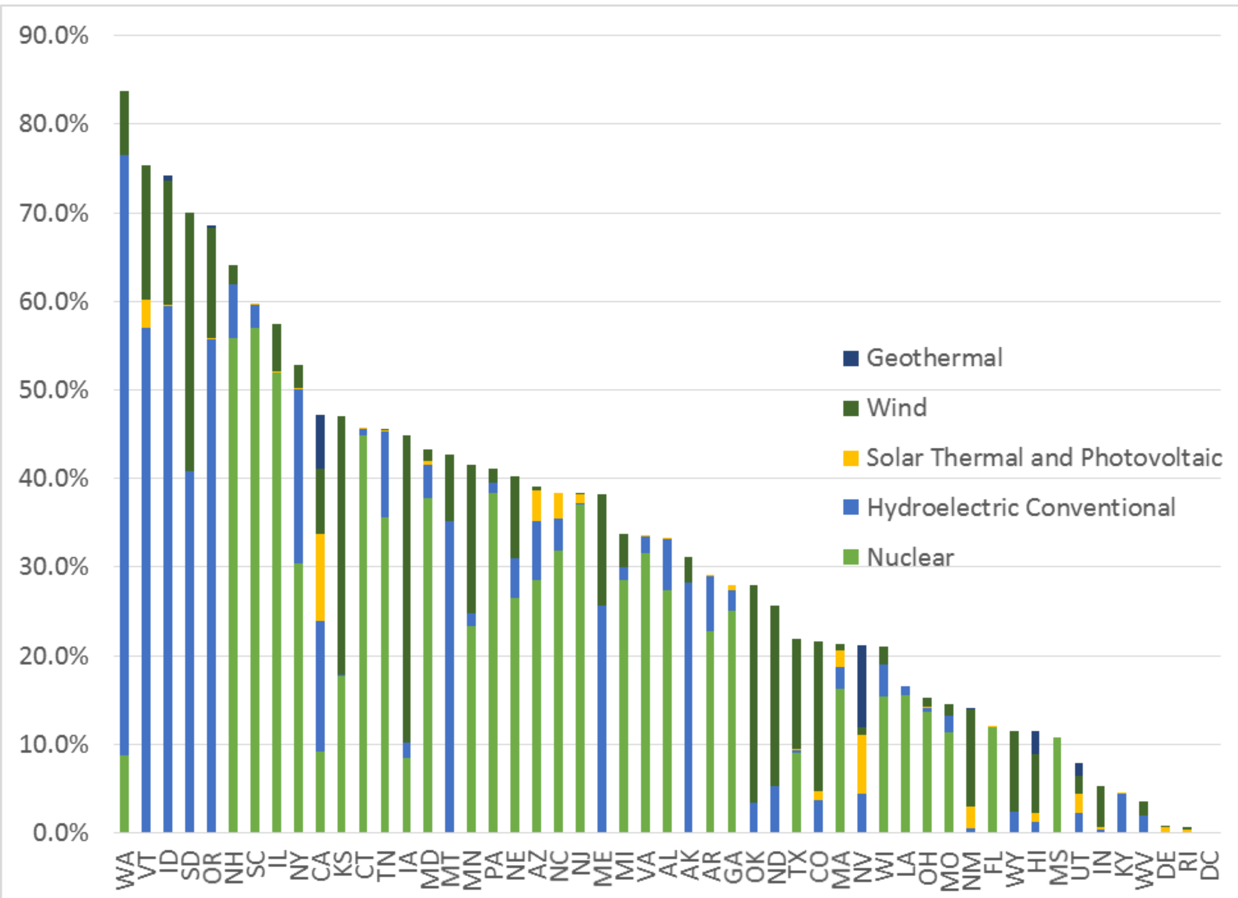
According to preliminary Energy Information Administration (EIA) data for 2016,[1] California generated 47.2% of electricity with zero emission sources including:

[1] US EIA Electric Power Monthly https://www.eia.gov/electricity/monthly/

- Nuclear: 9.2%
- Conventional Hydroelectric: 14.8%
- Solar Thermal and Photovoltaic: 9.8%
- Wind: 7.3%
- Geothermal: 6.1%

Including nuclear and hydroelectric generation, California ranks tenth compared to other states in terms of zero emission generation sources. However, California also has the most diverse portfolio of zero emission generation sources as illustrated in FigureF-1.

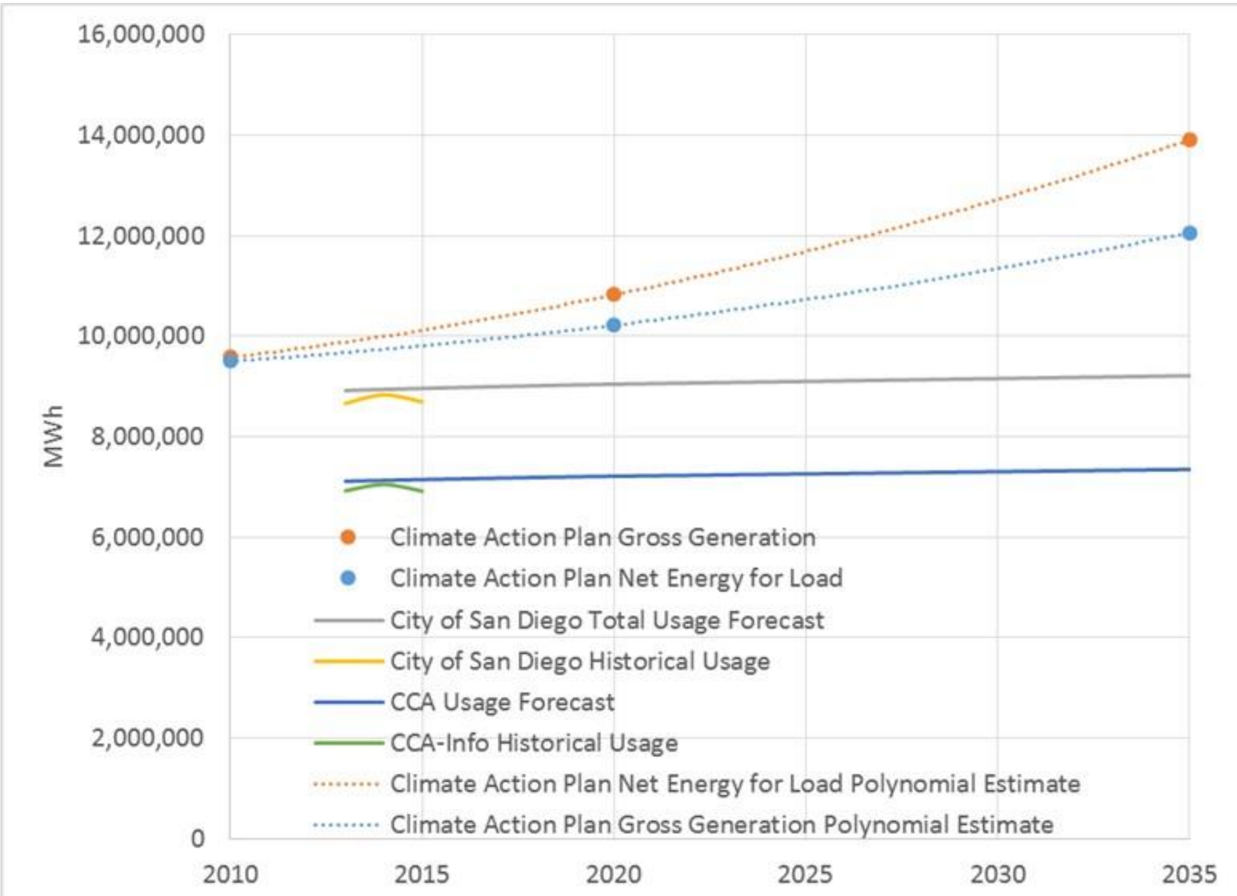
Figure F-1: Percentage of Zero Emissions Electricity Consumption by State



EMISSION REDUCTION COMPARISON WITH THE CLIMATE ACTION PLAN

The City of San Diego Climate Action Plan (CAP) [2] assumed a certain level of Net Energy for Load (GWh) based on linear load growth from 2010 to 2020; and then to 2035. This Study's load forecast, however, estimates 25% lower usage in 2035 than was estimated in the CAP, as depicted in Figure F-2 and Table F-1.

Figure F-2: Climate Action Plan and CCA Feasibility Report Forecast Comparison



[2] City of San Diego Climate Action Plan https://www.sandiego.gov/sites/default/files/final_july_2016_cap.pdf

Table F-1: City of San Diego Climate Action Plan Table 2, Net Energy and Generation Estimate and CCA Forecast Comparison

Forecast (MWh)	2010	2013	2014	2015	2020	2035
CAP Table 2 Net Energy for Load[3]	9,505,000				10,220,000	12,061,000
CAP Gross Generation[4]	9,580,000				10,826,000	13,910,000
City of San Diego Total Usage Forecast		8,921,014	8,942,709	8,962,954	9,047,866	9,215,353
City of San Diego Historical Usage		8,665,605	8,836,536	8,695,795		
City of San Diego Total Bundled Customer Usage Forecast		7,115,749	7,133,054	7,149,202	7,216,931	7,350,526
City of San Diego Bundled Customer Historical Usage Total		6,926,341	7,050,745	6,919,251		

Two primary factors contribute to this lower usage:

1. Lower load growth forecast in comparison with the CAP as detailed in Appendix D; and
2. Increasing customer adoption of PV system which reduces the amount of electricity provided by the LSE.

EMISSIONS FROM NATURAL GAS GENERATION

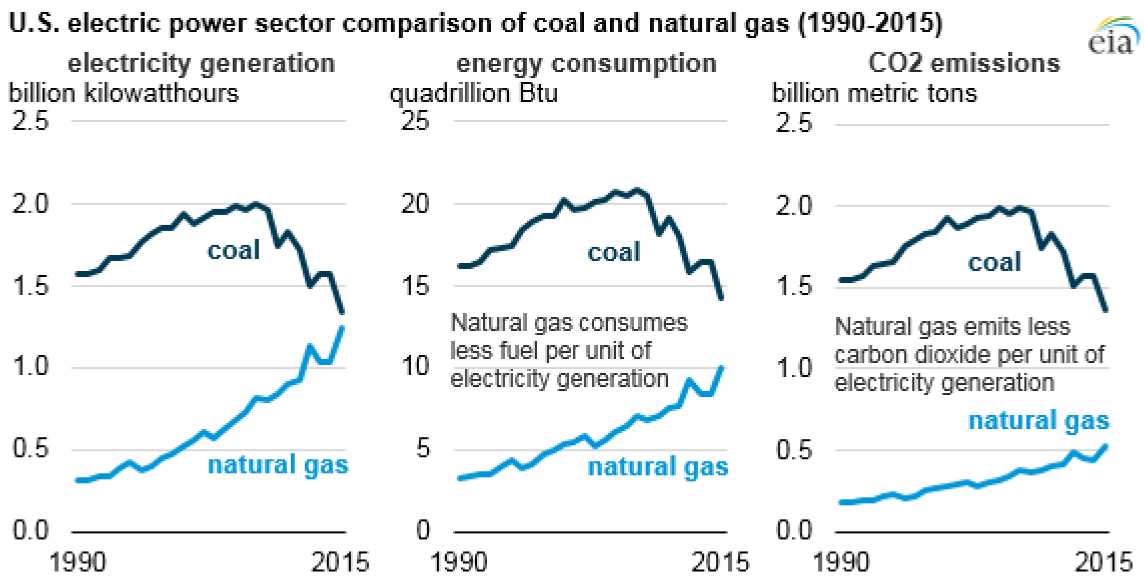
According to the EIA, "Carbon dioxide emissions from electricity generation in 2015 were lowest since 1993."[5] Figure F-3 from the EIA illustrates the increase in natural gas fueled generation and associated reduction in CO_2 emissions.

[3] San Diego CAP notation: Kavalec, Chris, Nicholas Fugate, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Kate Sullivan, and Malachi Weng-Gutierrez, 2013. California Energy Demand 2014-2024 Final Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency. California Energy Commission, Electricity Supply Analysis. Division. Publication Number: CEC-200-2013-004-SF-VI. Values beyond 2024 are extrapolated.

[4] San Diego CAP notation: Gross generation is the sum of net energy for load (GWh), additional electricity load in the City of San Diego from CA Electric Vehicle Policies and Program (includes transmission and distribution losses), and electricity generation from CA Solar Programs (does not include transmission and distribution losses).

[5] Carbon Dioxide emissions from the electric power sector: http://www.eia.gov/todayinenergy/detail.php?id=26232

Figure F-3: Comparison of Coal and Natural Gas Generation



According to the EIA,[6] in 2016 with a heat rate of 10,408, natural gas generation results in 1.22 pounds of CO_2 per kWh. 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. Per the CEC's Quarterly Fuels and Energy Report,[7] the heat rate for natural gas emissions in California in 2014 was 7,760, or 25% better than the EIA cited heat rate. This translates to an associated reduction in CO_2 emissions to 0.91 pounds of CO_2 per kWh. Additionally, the heat rate for natural gas generation has been improving over time and this Study assumes that it will continue to do so, as illustrated in Figure F-4.

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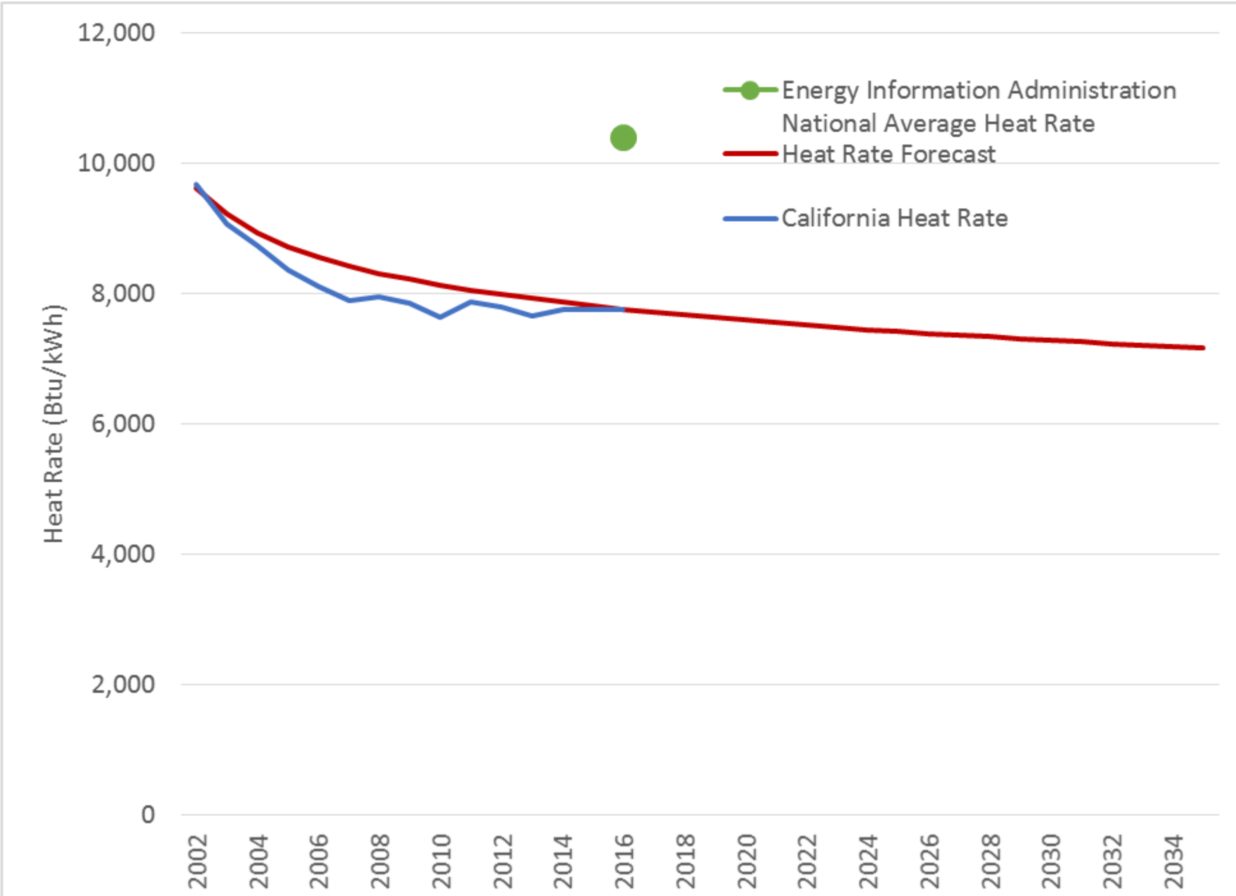
[6] EIA: Carbon dioxide is produced per kWh when generating electricity http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11

[7] 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

Figure F-4: Natural Gas Generation Heat Rate (Efficiency)



As a result, the CO_2 output from natural gas is continuing to improve compared to the prior San Diego baseline CAP emissions factor assumptions, as depicted in Table F-2. Even without the increase in RPC, combined with a citywide load forecast summarized in the same table, there is a significant improvement in emissions, which further reduce the weighted emissions factor.

Table F-2: Emissions Improvement Relative to San Diego CAP, Without Increased RPC

Year	CAP Gross Generation (MWh)	Baseline CAP Emissions Factor (lbs. CO_2e/MWh	CAP Baseline Emissions (CO_2e/MWh)	This Study's Forecasted All City Generation (MWh)	This Study's Forecasted Emissions Factor with NG Heat Rate Improvements (lbs. CO_2e/MWh)	This Study's Emissions, without additional RPC (CO_2e/MWh)	Combined % Improvement in Emissions, without additional RPC
2010	9,580,000	730	6,993,400,000				
2020	10,826,000	730	7,902,980,000	9,047,866	488	4,415,358,608	44%
2035	13,910,000	730	10,154,300,000	9,215,353	420	3,870,448,260	62%

CCA GREENHOUSE GAS EMISSIONS REDUCTION POTENTIAL

Consistent with direction from the State of California, the City has established a greenhouse gas reduction target of 50% below a 2010 baseline by 2035. Long-term reductions established by the state extend these targets to an 80% reduction by 2050. The largest sources of emissions in the City are from electricity, natural gas, and fossil fuel-based transportation. The City established its renewable energy policy and is pursuing a 100% renewable electricity goal in support of its overall greenhouse gas emissions reductions target. To determine the extent to which a CCA would achieve greenhouse gas emissions reductions through the use of renewable generation, forecasts of SDG&E's RPC need to be compared to the City CCA program's RPC Scenarios.

SDG&E currently has two major sources of energy supply: RPS-eligible resources and natural gas-fired resources as illustrated in Table F-3, its 2015 SDG&E Power Content Label.

Table F-3: 2015 SDG&E Power Content Label[8]

POWER CONTENT LABEL		
ENERGY RESOURCES	SDG&E 2015 POWER MIX (Actual)	2015 CA POWER MIX**
Eligible Renewable	**35%**	**22%**
-- Biomass & waste	2%	3%
-- Geothermal	0%	4%
-- Small hydroelectric	0%	1%
-- Solar	18%	6%
-- Wind	15%	8%
Coal	0%	6%
Large Hydroelectric	0%	5%
Natural Gas	54%	44%
Nuclear	0%	9%
Other	0%	0%
Unspecified sources of power*	**11%**	**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 **SDG&E**. For general information about the Power Content Label, contact the California Energy Commission at 1-844-217-4925 or http://www.energy.ca.gov/pcl/.

The 11% of unspecified sources of power in SDG&E's 2015 energy portfolio shown is likely comprised of CAISO supplied power, which was comprised of the following generation mix:[9]

- 40% Natural Gas
- 28% Import from other states
- 18% Non-Hydro Renewables
- 8% Nuclear
- 5% Hydroelectric

Per the CPUC RPS homepage,[10] SDG&E had actual past RPS compliance and forward contracts in place that exceed the California RPS requirements as shown in Table F-4.

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

[9] CAISO Annual Market Report: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

[10] California Renewables Portfolio Standard (RPS) http://www.cpuc.ca.gov/RPS_Homepage/

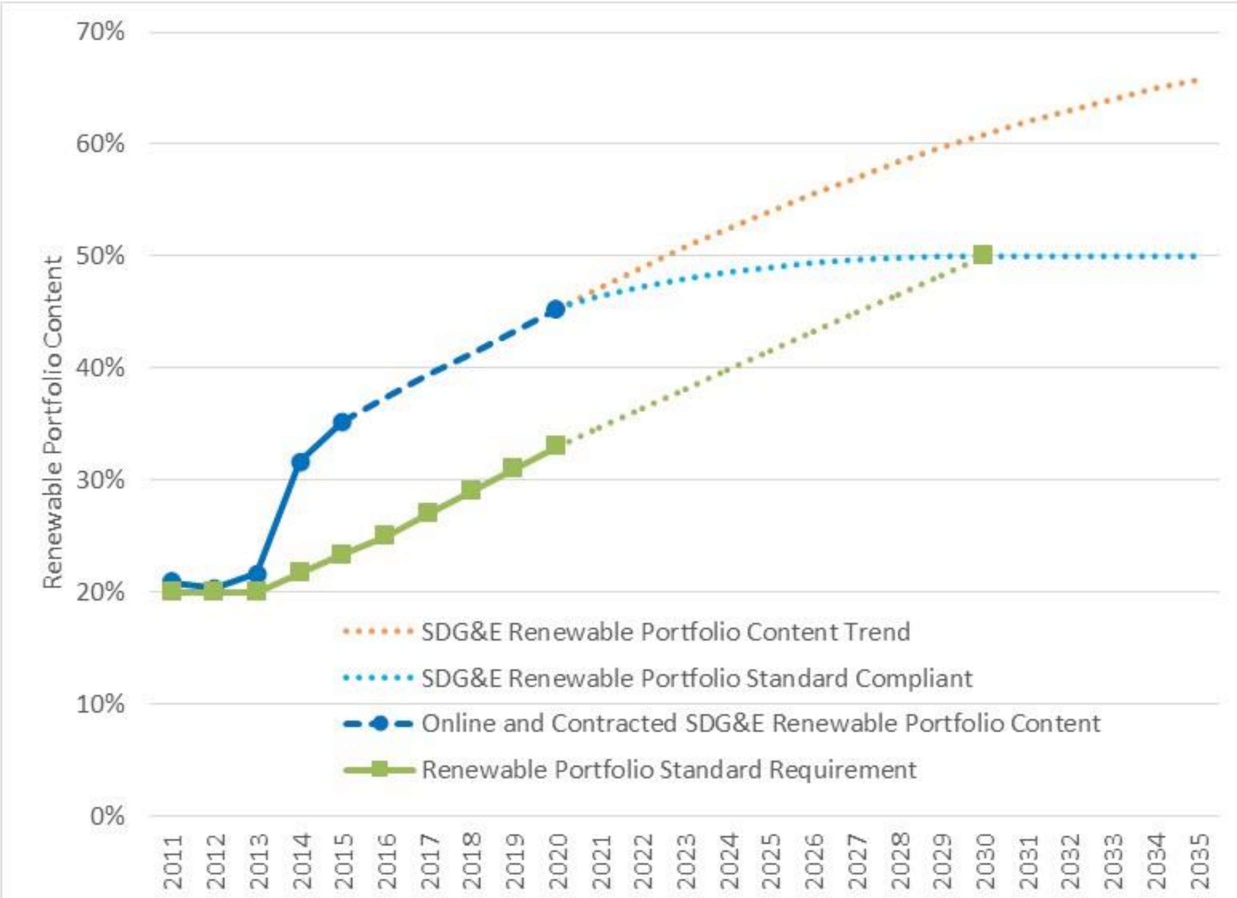
Table F-4: Actual and Contracted SDG&E RPS-Compliant Resources Relative to California RPS Requirements

Year	RPS Requirement[11]	Actual and Contracted SDG&E RPS %
2014	21.7%	31.6%
2015	23.3%	35.2%
2020	33%	45.2%
2030	50%	

Figure F-5 summarizes and forecasts the estimated SDG&E RPS-compliant generation for 2003 through 2030 based on SDG&E's contracted RPS PPAs. The Study assumes that SDG&E meets the 50% RPS goal in 2030 and maintains the 50% RPS until 2035. The Study forecast is shown in the light blue dotted line, labeled SDG&E Renewable Portfolio Standard Compliant. The assumption that SDG&E will only meet the 2030 50% RPS requirement may underestimate SDG&E's actual RPS for 2030, considering that SDG&E exceeded the 2014 goal by almost 10%, exceeded the 2015 goal by almost 12% and already has RPS contracts in place to exceed the 2020 RPS goal by over 12%. An alternative forecast for SDG&E's RPC, taking into account the history of exceeding RPS goals, is represented by the SDG&E Renewable Portfolio Content Trend line. This trend line, included solely for illustrative purposes, indicates that SDG&E could exceed 60% RPS by 2030 rather than just meeting the 50% RPS requirement. Both of these scenarios are considered in comparison with the CCA RPC Scenarios. However, SDG&E has not indicated it would exceed RPS requirements and this data is not used in Study results.

[11] California 33% RPS Procurement Rules: http://www.cpuc.ca.gov/RPS_Procurement_Rules_33/

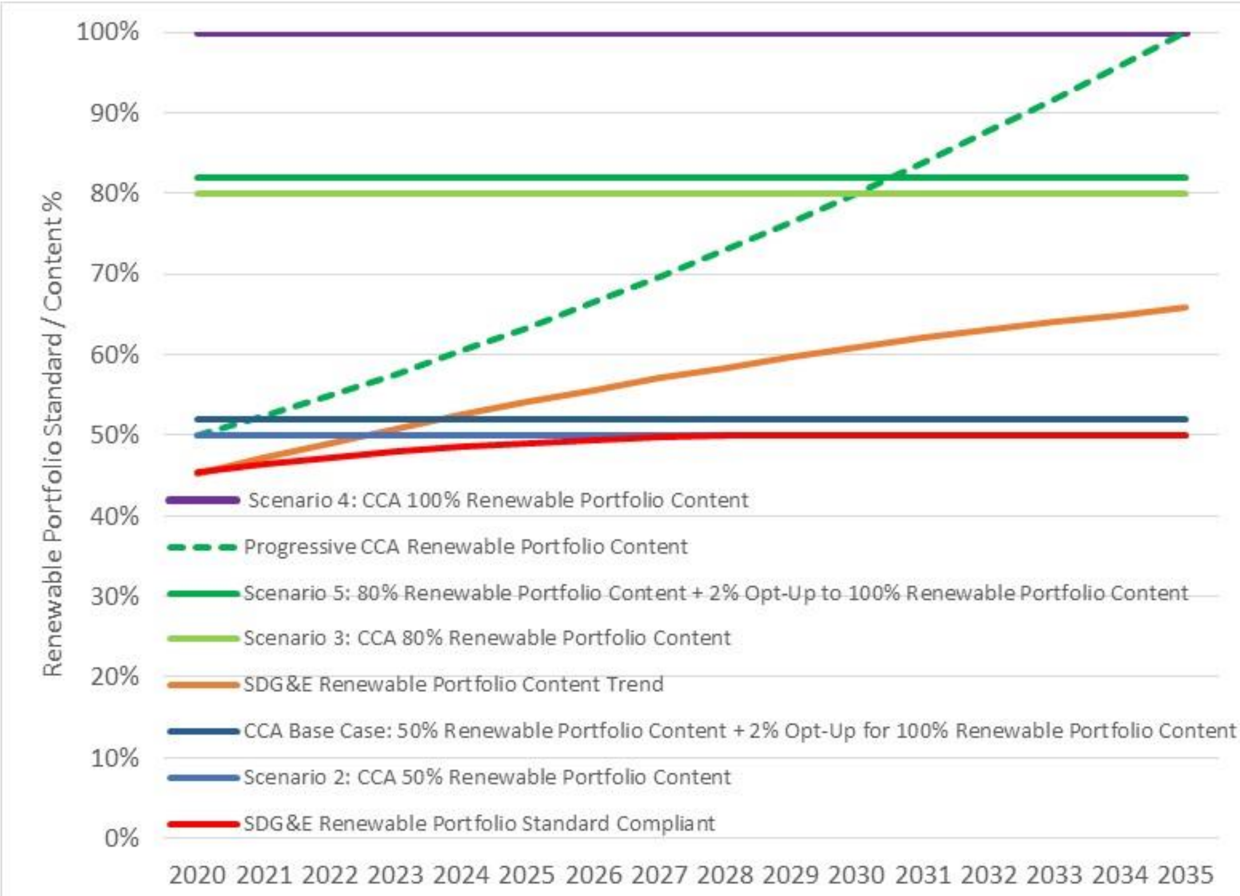
Figure F-5: Actual SDG&E RPS Generation 2003-15 and Estimated Annual SDG&E RPS Generation 2016 - 2030[12]



The SDG&E RPS trend line (based on historical data), the Study's SDG&E RPS estimate (not exceeding 50%) and the CCA RPC Scenarios are depicted in Figure F-6.

[12] CPUC RPS Monthly Project Status Table for SDG&E (updated August 10, 2016) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12370

Figure F-6: SDG&E RPS Estimate, SDG&E RPS Trend, and CCA RPC Scenarios



Including the improving heat rate for natural gas generation and increasing RPC for SDG&E yields a CO_2 equivalent per MWh comparison between the SDG&E RPS Trend, the Study's SDG&E RPS Estimate, and the CCA RPC Scenarios[13] as summarized in Table F-5. The emissions continue to decline post 2030, even in those Scenarios where the RPC meets the 2030 RPS requirement and then continues unchanged, due to the declining heat rate of natural gas-fired generation.

Table F-5: Estimated Weighted Emissions Factor for SDG&E and CCA RPC Scenarios

Year	Emissions Factor CO_2e	Study Forecast of SDG&E Pounds of CO_2e/MWh	SDG&E RPS Trend Pounds of CO_2e/MWh	CCA 50% RPC Pounds of CO_2e/MWh	CCA 80% RPC Pounds of CO_2e/MWh	CCA 100% RPC Pounds of CO_2e/MWh
2020	488	488	486	445	178	0
2021	481	481	468	443	177	0
2022	475	475	449	441	176	0

[13] It is assumed that direct access customer LSEs will also comply with RPS requirements. However, for the purposes of this Study it is assumed that direct access customers opt-out of CCA service.

Year	Emissions Factor CO_2e	Study Forecast of SDG&E Pounds of CO_2e/MWh	SDG&E RPS Trend Pounds of CO_2e/MWh	CCA 50% RPC Pounds of CO_2e/MWh	CCA 80% RPC Pounds of CO_2e/MWh	CCA 100% RPC Pounds of CO_2e/MWh
2023	468	468	432	439	175	0
2024	462	462	415	437	175	0
2025	456	456	400	435	174	0
2026	450	450	385	433	173	0
2027	444	444	371	432	173	0
2028	438	438	358	430	172	0
2029	433	433	346	428	171	0
2030	427	427	334	427	171	0
2031	426	426	323	426	170	0
2032	424	424	313	424	170	0
2033	423	423	304	423	169	0
2034	421	421	296	421	169	0
2035	420	420	288	420	168	0

Table F-6 provides a comparison of the SDG&E RPS Trend forecast and the CCA RPC Scenarios with the Study's forecast of SDG&E emissions. This data indicates:

- The SDG&E trend line forecast with more than 60% RPS by 2030 results in a 15% reduction in CO_2 emissions compared to the Study's forecast of SDG&E emissions.
- The 50% RPC CCA Scenario results in a 3% reduction in CO_2 emissions output compared to the Study's forecast of SDG&E emissions from 2020-2035.
- The 80% RPC CCA Scenario results in a 61% reduction in CO_2 emissions output compared to the Study's forecast of SDG&E emissions from 2020-2035.
- The 100% RPC CCA Scenario results in a 100% reduction in CO_2 emissions output compared to the Study's forecast of SDG&E emissions from 2020-2035.
- A hypothetical progression from 50% RPC in 2020 to 80% RPC in 2030 and 100% RPS in 2035 results in a 46% reduction in CO_2 emissions compared to the Study's forecast of SDG&E emissions from 2020-2035.

Table F-6: CO_2 Output Comparison with SDG&E

Year	SDG&E RPS Compliant Content Estimate		SDG&E RPS Trend [*]		CCA 50% RPC	CCA 80% RPC	CCA 100% RPC	Progressive CCA RPC	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
2020	45.2%	1.6	45.3%	1.6	1.4	0.6	-	50%	1.4
2021	45.7%	1.5	47.2%	1.5	1.4	0.6	-	52%	1.4
2022	46.2%	1.5	49.0%	1.4	1.4	0.6	-	55%	1.3
2023	46.6%	1.5	50.8%	1.4	1.4	0.6	-	58%	1.2
2024	47.1%	1.5	52.4%	1.3	1.4	0.6	-	60%	1.1
2025	47.6%	1.5	54.0%	1.3	1.4	0.6	-	63%	1.0
2026	48.1%	1.4	55.6%	1.2	1.4	0.6	-	66%	0.9
2027	48.6%	1.4	57.0%	1.2	1.4	0.6	-	70%	0.8
2028	49.0%	1.4	58.4%	1.1	1.4	0.6	-	73%	0.7
2029	49.5%	1.4	59.7%	1.1	1.4	0.5	-	76%	0.6
2030	50.0%	1.4	60.9%	1.1	1.4	0.5	-	80%	0.5
2031	50.0%	1.4	62.0%	1.0	1.4	0.5	-	84%	0.4
2032	50.0%	1.4	63.1%	1.0	1.4	0.5	-	88%	0.3
2033	50.0%	1.4	64.0%	1.0	1.4	0.5	-	92%	0.2
2034	50.0%	1.3	64.9%	0.9	1.3	0.5	-	96%	0.1
2035	50.0%	1.3	65.7%	0.9	1.3	0.5	-	100%	-
TOTAL		22.9		19.0 [*]	22.2	8.9	-		11.9
CO_2 Reduction over (c)					3%	61%	100%		48%
CO_2 Reduction over (c) (MMT)					0.7	14.0	22.9		11.0

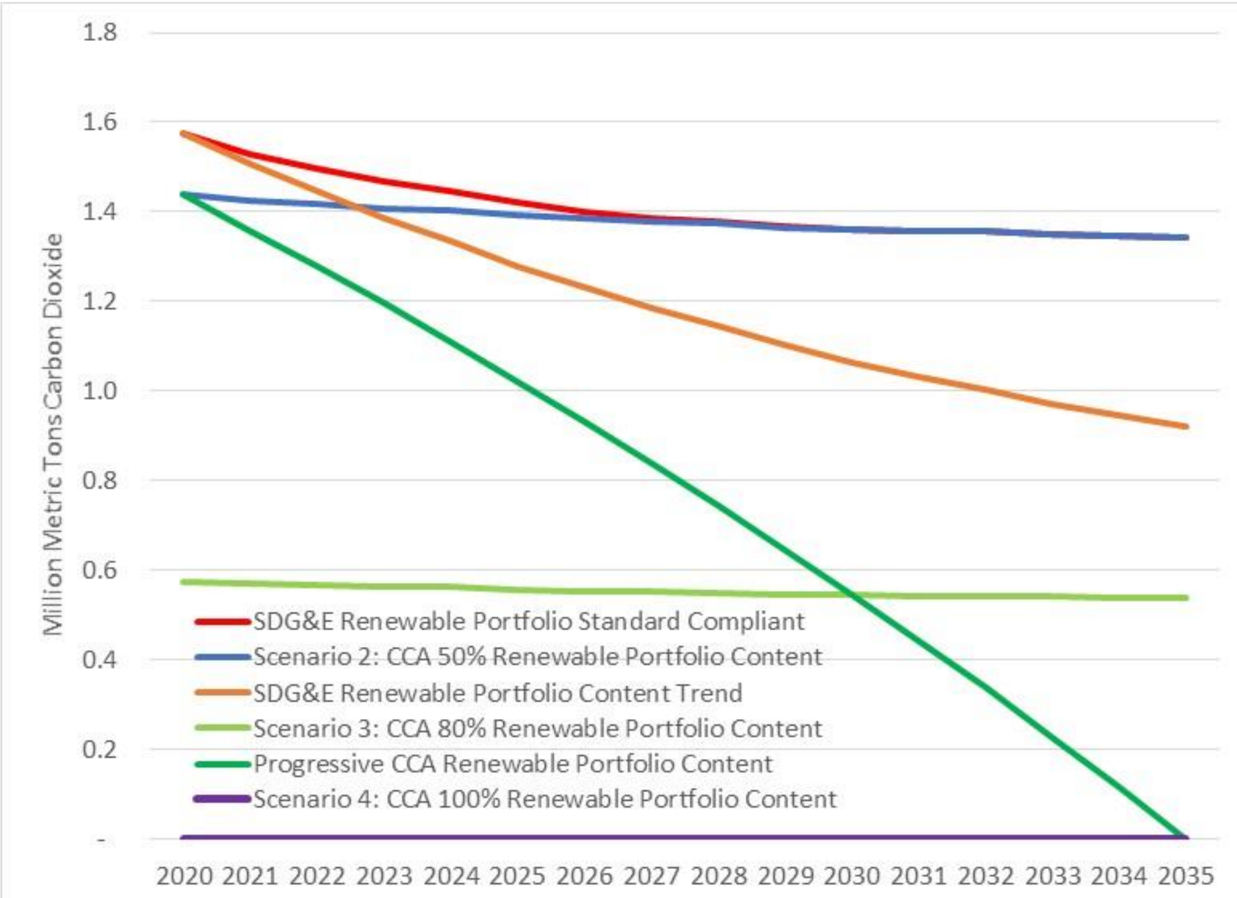
[*] For Illustrative purposes only; SDG&E has not indicated it would exceed RPS mandates.

Key:
- **RPS—California Renewable Portfolio Standard**
- **MMT—Million Metric Tons**
- **CO_2—Carbon Dioxide**
- **CCA—Community Choice Aggregation**
- **RPC—Renewable Portfolio Content**

Within the CAP,[14] the City identified a roughly 60% reduction in total GHG emissions in 2035 as a result of the CAP. This emissions reduction can be compared with the CO_2 reduction percentages displayed in Table F-6 for the different CCA RPC Scenarios. This data is illustrated graphically in Figure F-7.

[14] https://www.sandiego.gov/sites/default/files/final_july_2016_cap.pdf

Figure F-7: RPC Scenario Carbon Dioxide Emissions Comparison with SDG&E Projected RPS



APPENDIX G

SAN DIEGO GAS AND ELECTRIC RATES

APPENDIX G

SAN DIEGO GAS AND ELECTRIC RATES

The fundamental measure of CCA feasibility is the achievement of the CCA goals and objectives while maintaining competitive generation rates with SDG&E. SDG&E rate tariffs are regulated by the California Public Utilities Commission (CPUC). For residential customers, there are two primary components to the electricity rates: delivery service and electric commodity (generation), both assessed on a $ per kWh basis. For commercial and industrial customers, a demand charge may also be applicable, assessed on a $ per kW basis. SDG&E bundled customers receive both delivery and energy services from SDG&E and pay the applicable delivery service, demand, and generation rates. Direct Access and CCA customers pay SDG&E the delivery component while paying their CCA or energy service provider for the electric commodity (generation).

At the onset of electrification and for many decades after, a flat rate structure was used for electric utility services with a single price for each kWh consumed, no matter the amount. However, as energy efficiency and conservation goals came to the fore of public policy decision-making, utilities started implementing a tiered rate structure that encourages lower energy use. For years, the CPUC has required that California IOUs use a tiered rate structure, with the lowest rates applied to a set amount of initial use and increasing rates with increased energy consumption. The intent of this tiered rate structure was to encourage energy conservation and efficiency.

In October 2013, Governor Jerry Brown signed Assembly Bill (AB) 327 into law which made several changes to the IOU rate structures. First, AB 327 allows a new fixed monthly charge of up to $10, or up to $5 for California Alternate Rates for Energy (CARE)[1] customers. In addition, it requires a default residential rate with at least 2 tiers, with the Tier 1 usage level being no less than the mandated baseline allocation.[2]

AB 327 also authorizes the CPUC to potentially raise the required percentages of renewable energy, known as the Renewable Portfolio Standard (RPS), higher than the previously required 25% by 2016 and 33% by 2020 and 50% by 2030. For example, the CPUC could decide to raise the required RPS, to say, 45% by 2025. Changes under AB 327 will not go into effect until they are approved by the CPUC.

SDG&E files general rate cases with the CPUC with each covering a three-year period of operations. 2016 is a "test year" for the current SDG&E general rate case cycle[3]. A general rate case provides SDG&E funding application details for infrastructure investment, customer service, and power procurement. The SDG&E 2016 general rate case is considered by the CPUC in two phases:

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[1] SDG&E California Alternate Rates for Energy (CARE): http://www.sdge.com/residential/care-video

[2] SDG&E Understanding Rates: http://www.sdge.com/understanding-rates

[3] San Diego Gas and Electric (SDG&E) General Rate Case (GRC) Proceedings (Phase I): http://www.cpuc.ca.gov/General.aspx?id=10434

- Phase 1 Application 14-11-003[4] determining the total amount the utility is authorized to collect; and
- Phase 2 Application 15-04-012[5] determining the share of the cost each customer class is responsible and the rate schedules for each class.

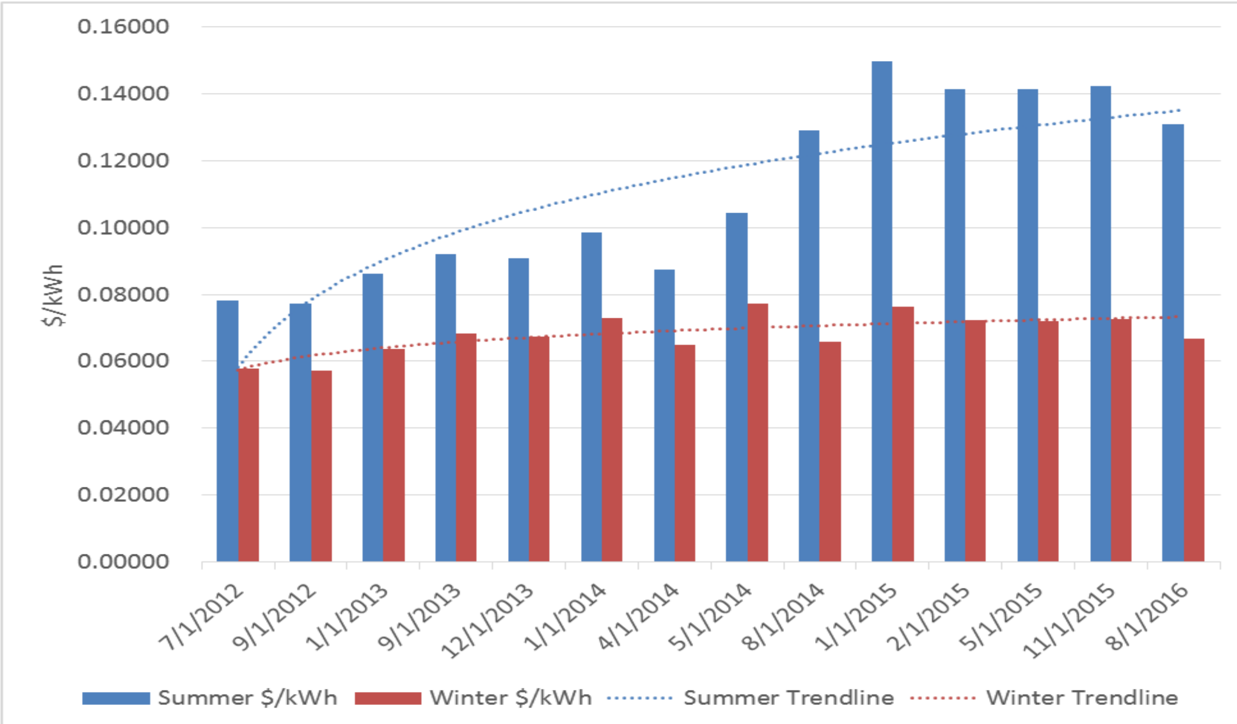
SDG&E also files Rate Design Window applications with the CPUC in intermittent years for changes to rates.

SDG&E RESIDENTIAL GENERATION RATES

The generation rate is the component of the SDG&E rate tariffs that the City CCA program customers would stop paying and begin paying the CCA, based on the rates developed and approved by the San Diego City Council or another CCA oversight board option. Figure G-1 provides an overview of the SDG&E residential generation rates since 2012 based on a "SDG&E Commodity Rates" summary provided by SDG&E.

[4] SDG&E 2016 GRC Phase 1: http://www.sdge.com/regulatory-filing/12931/sdge-grc-testimony-exhibit-list
[5] SDG&E 2016 GRC Phase 2: http://www.sdge.com/sdge-2016-GRC-Phase-2

Figure G-1: SDG&E Residential Generation Rates



SDG&E COMMERCIAL AND INDUSTRIAL GENERATION RATES

The CPUC ordered SDG&E to implement mandatory Time of Use (TOU) rates for small and medium commercial customers with up to 200 kW demand starting in 2014[6] and mandatory Critical Peak Pricing (CPP) rates for large commercial customers with over 200 kW demand starting in 2007.[7] SDG&E customers are defaulted to a certain rate, but have the option of selecting an alternative rate:

- CPP rates seek to impose higher electricity prices on the days of highest electricity usage (peak days). Generation capacity needs to be available to meet the demand on those peak days despite the fact that only six to twelve peak days occur per year. Electricity tends to get more expensive as demand approaches the available capacity (as would be expected in a typical commodity supply and demand market). Therefore, imposing higher prices on the days that high demand is forecasted should result in a lower demand. CPP rates became default for SDG&E customers in 2007.
- Real Time Pricing (RTP) seeks to align retail electricity pricing with the real-time cost of supply. True RTP programs have been limited to date for a variety of reasons including:
- The market prices available through a Regional Transmission Organizations (RTO) or Independent System Operators, like CAISO, reflect day-ahead and real-time market prices that are not

[6] SDG&E Application 11-10-002 and subsequent CPUC Decision 14-01-002, January 16, 2014

[7] CPUC Decision 05-04-053 addressed CPP rates for customers with greater than 200 kW of demand; SDG&E Application 05-01-017 followed Decision 05-04-053 and proposed a default CPP Structure for commercial and industrial customers with peak demands exceeding 300 kW; CPUC Decision D0605038 adopted default critical peak pricing for 2007.

necessarily correlated with the total supply portfolio at any given time. For instance, ample supply may be available, but if non-dispatchable (renewable) generation deviates from the expected output, market prices may spike or drop drastically to incentivize immediate response and keep electricity supply and demand in balance.

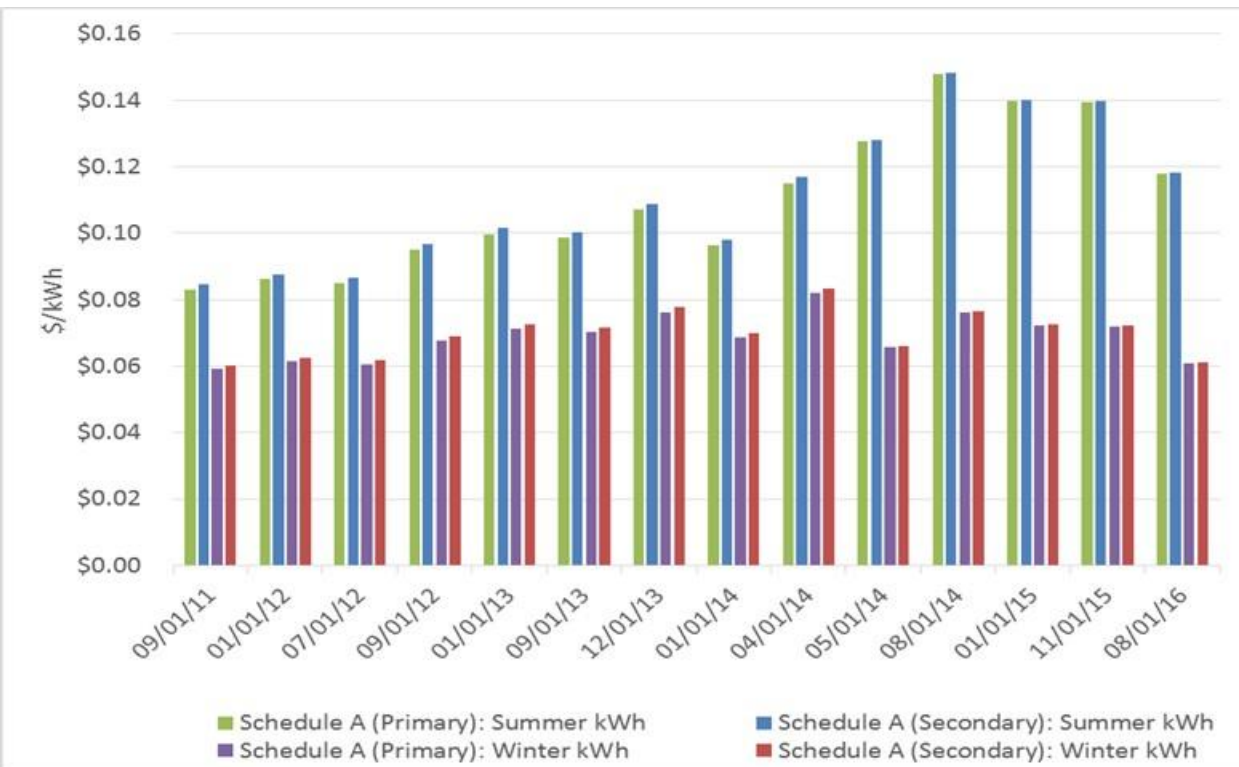
- The demand response technology needed for customers to respond to fluctuations in real-time market prices is still maturing
- The Federal Energy Regulatory Commission (FERC) is the ISO and RTO regulatory authority while state utility commissions, such as the CPUC, have jurisdiction over IOU retail rates.

SDG&E classifies commercial and industrial customers based on the industry or use for the electricity, as well as the amount of demand by the customer. In keeping with the logic to promote conservation and energy efficiency through increased prices for higher usage, often larger customers pay higher rates than smaller customers. The different SDG&E commercial and industrial rate classes applicable within the City CCA program's territory are described and summarized in the following bulleted discussion points and Figures. Supplemental data used to create these Figures is provided in the last segment of this Appendix.

Small Commercial Customers - Schedule A (General Service)

This rate class includes single- and three-phase commercial and three-phase residential service including lighting and power, except that the customer whose monthly maximum demand exceeds or is expected to exceed 20 kW or has exceeded 20 kW for 12 consecutive months.

Figure G-2: Schedule A Electric Energy Commodity Cost (EECC)



Large Commercial Customer - Schedule AL-TOU (General Service – Time Metered)

Applicable to all metered non-residential customers whose Monthly Maximum Demand equals, exceeds, or is expected to equal or exceed 20 kW. This schedule is the utility's standard tariff for commercial and industrial customers with a Monthly Maximum Demand equaling or exceeding 20 kW. Customers on this Schedule whose Monthly Maximum Demand is not less than 20 kW for three consecutive months will also take commodity service on Schedule EECC-CPP-D. Figure G-3 provides Schedule AL, EECC, by service level, season, and time period from September 2011 through August 2016. Figure G-4 provides the Critical Peak Pricing Commodity Cost, by service level, season, and time period from September 2012 through August 2016.

Schedule AY-TOU (General Service – Time Metered)

- As of September, 1999, this schedule is closed to any new customers. This schedule is optionally available to all metered non-residential customers who request service on this schedule and whose maximum annual demand does not exceed 500 kW. Customers on this Schedule whose Monthly Maximum Demand is not less than 20 kW for three consecutive months will also take commodity service on Schedule EECC-CPP-D.
- Large Commercial & Industrial - Schedule A6- TOU (General Service – Time Metered Optional)
- This schedule is optionally available to customers receiving service at Primary, Primary Substation, or Transmission service voltage level, as defined in Rule 1, whose maximum demand is 500 kW or greater during any 15-minute interval of the most recent 12-month period.

Figure G-3: Schedule AL Electric Energy Commodity Cost (EECC)

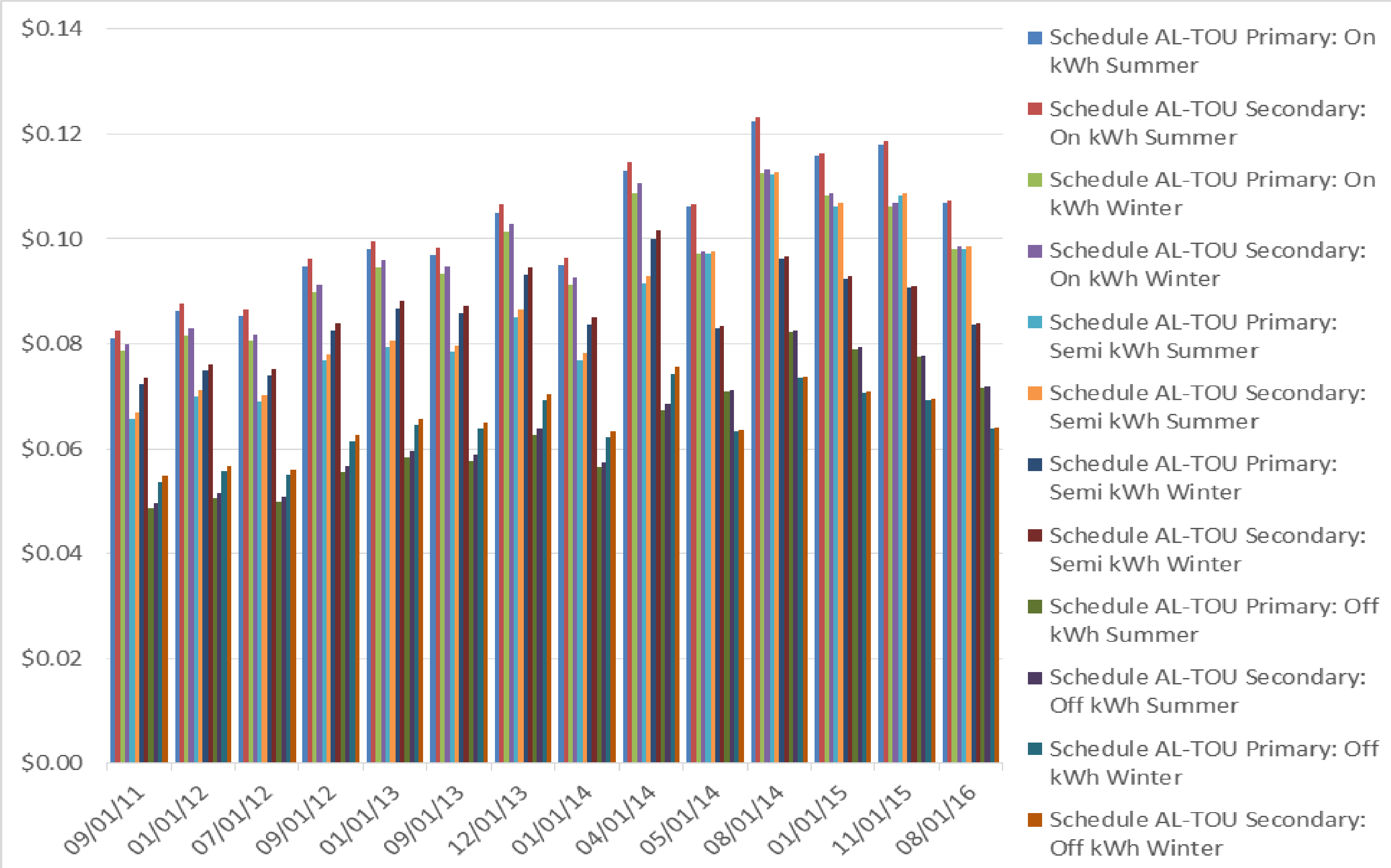
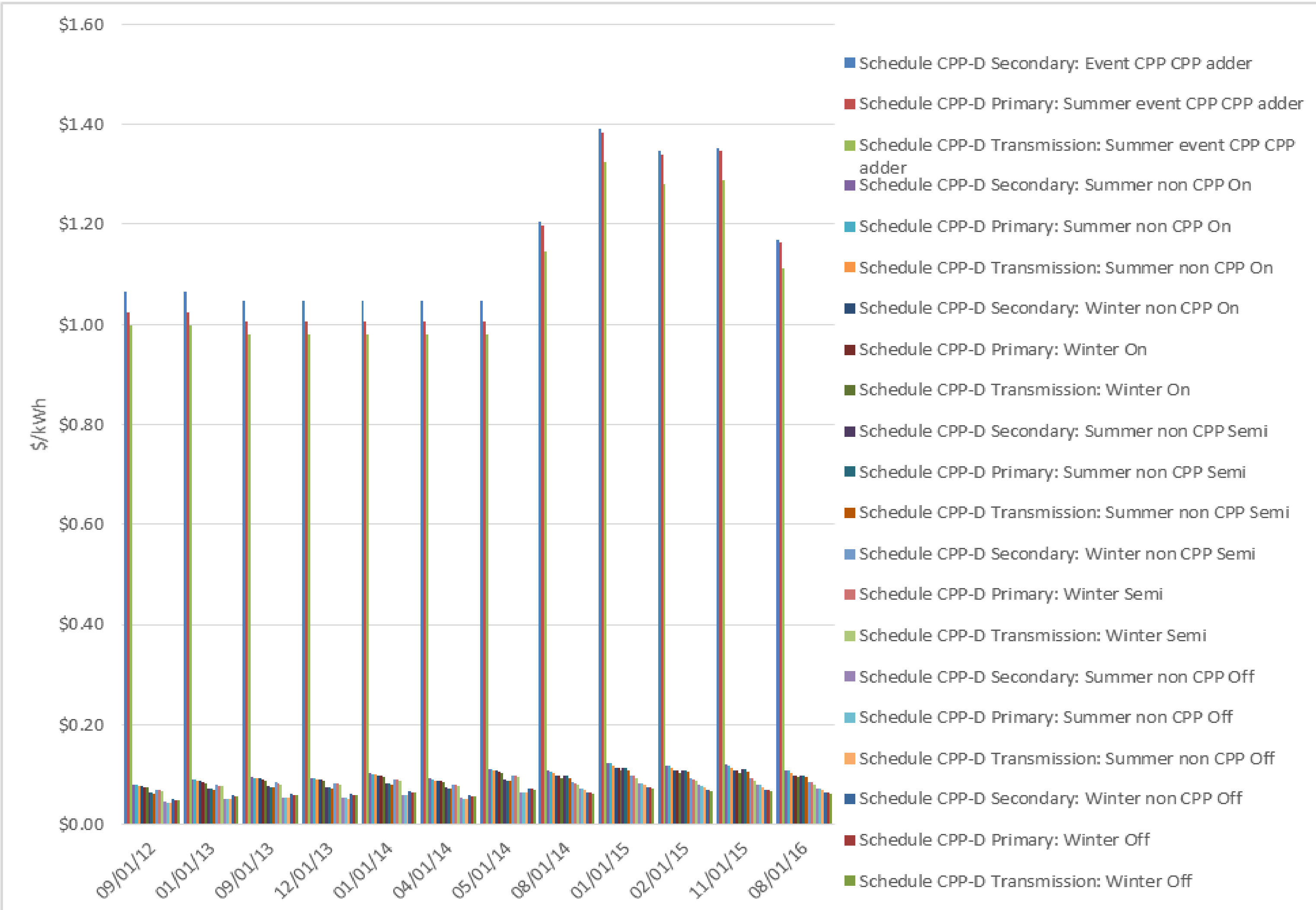


Figure G-4: Critical Peak Pricing Commodity Cost



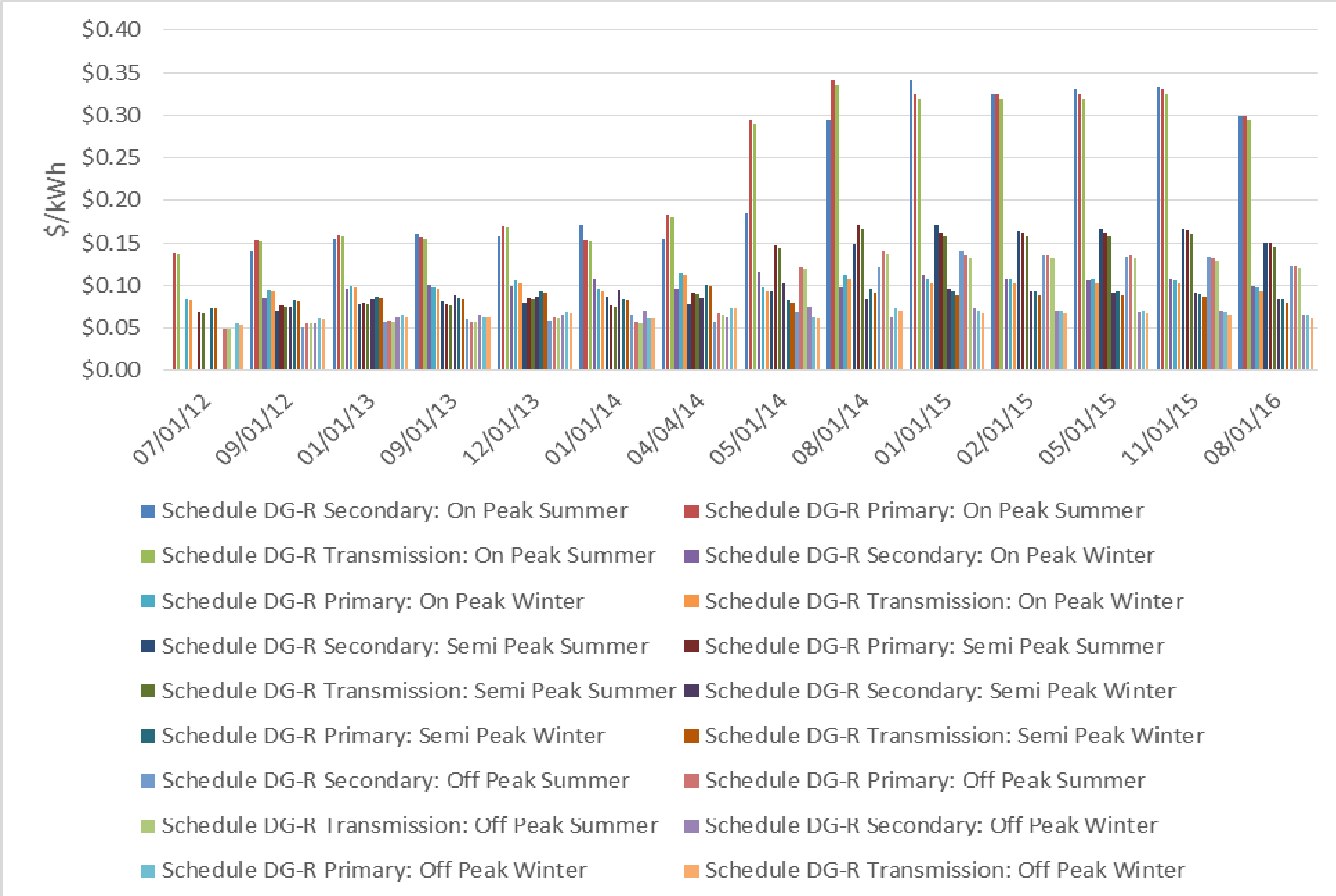
PA-T-1 (Experimental Power - Agricultural - Optional Time-Of-Use)

- This is an optional schedule provided by the utility, on an experimental basis, for the purpose of evaluating time varying rates. Available to agricultural and water pumping customers whose Maximum Monthly Demand is expected to be above 500 kW. This schedule is also available to those agricultural and water pumping customers whose maximum demand is less than 500 kW who are installing or have installed facilities or procedures to reduce their annual on-peak energy consumption by 1,500 kWh. Customers on this Schedule whose Monthly Maximum Demand is not less than 200 kW will also take commodity service on Schedule EECC-CPP-D-AG.

Schedule DG-R, Distributed Generation Renewable - Time Metered

Service under this Schedule is available on a voluntary basis for all metered non-residential customers whose peak annual load is equal to or less than 2MW, and who have operational, distributed generation, and the capacity of that operational distributed generation is equal to or greater than 10% of their peak annual load. Distributed generation that qualifies for service under this Schedule is limited to solar, fuel cells (regardless of fuel source), and other renewable distributed generation, as more fully defined in Special Condition 17, fueled with gas derived from biomass, digester gas, or landfill gas. Figure G-5 provides Schedule DG-R, the Distributed Generation Renewable EECC, by service level, season, and time period from July 2012 through August 2016.

Figure G-5: Schedule DG-R Distributed Generation Renewable Electric Energy Commodity Cost (EECC)



A-TC (Traffic Control Service)

- Applicable to local, state or other governmental agencies for service to traffic signal systems utilized 24 hours per day, located on streets, highways or other public thoroughfares. This schedule is closed to new customers with non-residential loads that maintain a minimum annual load factor of at least 90 percent, as demonstrated by load sampling, and to customer owned outdoor area lighting furnished from dusk to dawn where photo cells have been installed on all loads.
- Schedule OL-TOU, Outdoor Lighting - Time Metered.
- LS2 (Lighting - Street and Highway Customer-Owned System).
- Applicable for service to governmental agencies and lighting districts for the lighting of streets, highways and other thoroughfares, and to other corporate agencies for the lighting of non-dedicated streets which are accessible to the public, where the customer owns the entire installation, including underground lines from a central point of connection with utility facilities.

BILLING OPTIONS FOR CUSTOMERS

In addition to the tariff rates described above, there are payment programs available to customers:

- Low income discount programs like the CARE program charge lower delivery rates to low income customers under certain qualifying criteria. This SDG&E program is applicable to the delivery charge and would still be available to CCA customers after implementation.
- Level pay plans seek to provide customers with a consistent bill to assist customers in their monthly budgeting. Level pay plans are based on the forecasted average annual bill with scheduled true-up periods to adjust for actual usage that is either above or below the forecasted usage.
- Pre-pay programs enable customers to purchase their electricity prior to consumption. This has been a growing trend for the telecom industry, with pre-paid cell phones and long distance cards. IOUs operating in the State are exploring pre-pay options but have not yet implemented any programs.

COST RESPONSIBILITY SURCHARGE AND POWER CHARGE INDIFFERENCE ADJUSTMENT

The Cost Responsibility Surcharge (CRS) and Power Charge Indifference Adjustment (PCIA) are intended to facilitate the CPUC Section 366.2(c)(3) requirements prohibiting cost shifting between bundled and CCA customers:

> *"It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the Department of Water Resources' electricity purchase costs, as well as electricity purchase contract obligations incurred as of the effective date of the act adding this section, that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.*

A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following:

The electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.

Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation."

SUPPLEMENTAL COMMERCIAL AND INDUSTRIAL RATE SCHEDULES

The detailed data forming the basis for Figures pertaining to commercial and industrial customers within this Appendix are provided in the following supplemental Tables G-1 through G-9.

Table G-1: Small Commercial Customers - Schedule A (General Service)

	Primary Voltage		Secondary Voltage	
Effective Date	Summer	Winter	Summer	Winter
9/1/2011	$0.08304	$0.05922	$0.08449	$0.06026
1/1/2012	$0.08609	$0.06139	$0.08760	$0.06248
7/1/2012	$0.08499	$0.06061	$0.08648	$0.06168
9/1/2012	$0.09488	$0.06766	$0.09654	$0.06886
1/1/2013	$0.09973	$0.07112	$0.10148	$0.07238
9/1/2013	$0.09850	$0.07024	$0.10023	$0.07149
12/1/2013	$0.10694	$0.07626	$0.10882	$0.07761
1/1/2014	$0.09621	$0.06861	$0.09790	$0.06983
4/1/2014	$0.11487	$0.08192	$0.11688	$0.08337
5/1/2014	$0.12749	$0.06580	$0.12781	$0.06605
8/1/2014	$0.14774	$0.07625	$0.14810	$0.07655
1/1/2015	$0.13971	$0.07210	$0.14006	$0.07239
11/1/2015	$0.13945	$0.07197	$0.13979	$0.07225
8/1/2016	$0.11786	$0.06083	$0.11815	$0.06106

Table G-2: Large Commercial Customer - Schedule AL-TOU (General Service – Time Metered), Primary Voltage

Primary Voltage						
	Summer			Winter		
Effective Date	Off Peak	On Peak	Semi Peak	Off Peak	On Peak	Semi Peak
9/1/2011	$0.04870	$0.08115	$0.06572	$0.05373	$0.07873	$0.07231
1/1/2012	$0.05047	$0.08634	$0.06993	$0.05569	$0.08160	$0.07495
7/1/2012	$0.04983	$0.08528	$0.06907	$0.05498	$0.08056	$0.07400
9/1/2012	$0.05562	$0.09481	$0.07679	$0.06137	$0.08993	$0.08260
1/1/2013	$0.05847	$0.09808	$0.07943	$0.06451	$0.09453	$0.08682
9/1/2013	$0.05775	$0.09689	$0.07847	$0.06372	$0.09336	$0.08575
12/1/2013	$0.06269	$0.10503	$0.08506	$0.06918	$0.10136	$0.09310
1/1/2014	$0.05641	$0.09495	$0.07690	$0.06224	$0.09120	$0.08377
4/1/2014	$0.06734	$0.11293	$0.09146	$0.07431	$0.10887	$0.10000
5/1/2014	$0.07094	$0.10607	$0.09711	$0.06338	$0.09719	$0.08297
8/1/2014	$0.08220	$0.12256	$0.11226	$0.07344	$0.11262	$0.09614
1/1/2015	$0.07904	$0.11577	$0.10626	$0.07061	$0.10829	$0.09244
11/1/2015	$0.07756	$0.11800	$0.10831	$0.06929	$0.10626	$0.09071
8/1/2016	$0.07154	$0.10682	$0.09805	$0.06391	$0.09801	$0.08366

Table G-3: Large Commercial Customer - Schedule AL-TOU (General Service – Time Metered), Secondary Voltage

Secondary Voltage						
	Summer			Winter		
Effective Date	Off Peak	On Peak	Semi Peak	Off Peak	On Peak	Semi Peak
9/1/2011	$0.04962	$0.08242	$0.06678	$0.05476	$0.07993	$0.07349
1/1/2012	$0.05143	$0.08769	$0.07105	$0.05676	$0.08285	$0.07617
7/1/2012	$0.05078	$0.08661	$0.07018	$0.05603	$0.08179	$0.07520
9/1/2012	$0.05668	$0.09629	$0.07802	$0.06255	$0.09130	$0.08394
1/1/2013	$0.05958	$0.09961	$0.08071	$0.06575	$0.09597	$0.08823
9/1/2013	$0.05884	$0.09840	$0.07973	$0.06494	$0.09479	$0.08714
12/1/2013	$0.06388	$0.10667	$0.08643	$0.07050	$0.10290	$0.09461
1/1/2014	$0.05748	$0.09643	$0.07814	$0.06343	$0.09259	$0.08513
4/1/2014	$0.06862	$0.11469	$0.09293	$0.07573	$0.11054	$0.10162
5/1/2014	$0.07119	$0.10664	$0.09759	$0.06359	$0.09767	$0.08334
8/1/2014	$0.08250	$0.12322	$0.11280	$0.07369	$0.11318	$0.09657
1/1/2015	$0.07933	$0.11637	$0.10676	$0.07085	$0.10882	$0.09285
11/1/2015	$0.07784	$0.11861	$0.10881	$0.06953	$0.10679	$0.09111
8/1/2016	$0.07179	$0.10738	$0.09850	$0.06412	$0.09849	$0.08403

Table G-4: Large Commercial & Industrial - Schedule A6- TOU (General Service – Time Metered Optional), Primary Voltage

Primary Voltage							
		Summer			Winter		
Effective Date	CPP Adder	Off Peak	On Peak	Semi Peak	Off Peak	On Peak	Semi Peak
9/1/2012	$1.02448	$0.04384	$0.07897	$0.06278	$0.04899	$0.07455	$0.06799
1/1/2013	$1.02448	$0.05036	$0.08923	$0.07123	$0.05611	$0.08465	$0.07732
9/1/2013	$1.00644	$0.05356	$0.09315	$0.07449	$0.05960	$0.08960	$0.08190
12/1/2013	$1.00644	$0.05275	$0.09187	$0.07344	$0.05871	$0.08834	$0.08074
1/1/2014	$1.00644	$0.05831	$0.10063	$0.08065	$0.06479	$0.09696	$0.08870
4/1/2014	$1.00657	$0.05124	$0.08977	$0.07173	$0.05707	$0.08601	$0.07858
5/1/2014	$1.00657	$0.06354	$0.10912	$0.08766	$0.07050	$0.10505	$0.09618
8/1/2014	$1.19759	$0.07094	$0.10608	$0.09713	$0.06338	$0.09719	$0.08297
1/1/2015	$1.38452	$0.08220	$0.12258	$0.11227	$0.07344	$0.11262	$0.09614
2/1/2015	$1.33946	$0.07771	$0.11821	$0.10850	$0.06942	$0.10646	$0.09088
11/1/2015	$1.34606	$0.07810	$0.11878	$0.10903	$0.06977	$0.10700	$0.09134
8/1/2016	$1.16246	$0.07154	$0.10679	$0.09802	$0.06391	$0.09801	$0.08366

Table G-5: Large Commercial & Industrial - Schedule A6- TOU (General Service – Time Metered Optional), Secondary Voltage

Secondary Voltage							
	Summer				Winter		
Effective Date	CPP Adder	Off Peak	On Peak	Semi Peak	Off Peak	On Peak	Semi Peak
9/1/2012	$1.06575	$0.04478	$0.08030	$0.06389	$0.05004	$0.07578	$0.06919
1/1/2013	$1.06575	$0.05141	$0.09071	$0.07246	$0.05728	$0.08602	$0.07866
9/1/2013	$1.04698	$0.05467	$0.09468	$0.07577	$0.06083	$0.09104	$0.08331
12/1/2013	$1.04698	$0.05384	$0.09338	$0.07470	$0.05993	$0.08977	$0.08213
1/1/2014	$1.04698	$0.05950	$0.10227	$0.08202	$0.06611	$0.09851	$0.09021
4/1/2014	$1.04712	$0.05231	$0.09125	$0.07297	$0.05826	$0.08740	$0.07994
5/1/2014	$1.04712	$0.06482	$0.11088	$0.08913	$0.07192	$0.10671	$0.09781
8/1/2014	$1.20453	$0.07119	$0.10665	$0.09760	$0.06359	$0.09767	$0.08334
1/1/2015	$1.39243	$0.08250	$0.12323	$0.11281	$0.07369	$0.11318	$0.09657
2/1/2015	$1.34641	$0.07799	$0.11882	$0.10901	$0.06966	$0.10699	$0.09128
11/1/2015	$1.35304	$0.07838	$0.11940	$0.10954	$0.07001	$0.10752	$0.09174
8/1/2016	$1.16848	$0.07179	$0.10734	$0.09848	$0.06412	$0.09849	$0.08403

Table G-6: Large Commercial & Industrial - Schedule A6- TOU (General Service – Time Metered Optional), Transmission Voltage

Effective Date	Transmission Voltage						
	Summer				Winter		
	CPP Adder	Off Peak	On Peak	Semi Peak	Off Peak	On Peak	Semi Peak
9/1/2012	$0.99849	$0.04318	$0.07751	$0.06167	$0.04827	$0.07312	$0.06681
1/1/2013	$0.99849	$0.04962	$0.08760	$0.06999	$0.05530	$0.08304	$0.07601
9/1/2013	$0.98091	$0.05279	$0.09146	$0.07321	$0.05875	$0.08792	$0.08052
12/1/2013	$0.98091	$0.05198	$0.09020	$0.07217	$0.05788	$0.08668	$0.07937
1/1/2014	$0.98091	$0.05749	$0.09882	$0.07927	$0.06388	$0.09515	$0.08722
4/1/2014	$0.98103	$0.05049	$0.08814	$0.07049	$0.05625	$0.08438	$0.07725
5/1/2014	$0.98103	$0.06265	$0.10718	$0.08618	$0.06952	$0.10311	$0.09459
8/1/2014	$1.14523	$0.06806	$0.10147	$0.09306	$0.06082	$0.09301	$0.07952
1/1/2015	$1.32393	$0.07887	$0.11724	$0.10756	$0.07048	$0.10778	$0.09215
2/1/2015	$1.28046	$0.07456	$0.11300	$0.10390	$0.06662	$0.10189	$0.08711
11/1/2015	$1.28678	$0.07493	$0.11355	$0.10441	$0.06696	$0.10239	$0.08754
8/1/2016	$1.11128	$0.06864	$0.10209	$0.09386	$0.06133	$0.09379	$0.08019

Table G-7: Schedule DG-R, Distributed Generation Renewable - Time Metered, Primary Voltage

	Primary Voltage					
	Summer			Winter		
Effective Date	Off Peak	On Peak	Semi Peak	Off Peak	On Peak	Semi Peak
7/1/2012	$0.04983	$0.13817	$0.06907	$0.05498	$0.08433	$0.07400
9/1/2012	$0.05562	$0.15361	$0.07679	$0.06137	$0.09413	$0.08260
1/1/2013	$0.05847	$0.15890	$0.07943	$0.06451	$0.09895	$0.08682
9/1/2013	$0.05775	$0.15698	$0.07847	$0.06372	$0.09772	$0.08575
12/1/2013	$0.06269	$0.17016	$0.08506	$0.06918	$0.10610	$0.09310
1/1/2014	$0.05641	$0.15383	$0.07690	$0.06224	$0.09546	$0.08377
4/4/2014	$0.06734	$0.18296	$0.09146	$0.07431	$0.11397	$0.10000
5/1/2014	$0.12149	$0.29459	$0.14767	$0.06338	$0.09720	$0.08297
8/1/2014	$0.14078	$0.34081	$0.17084	$0.07344	$0.11263	$0.09614
1/1/2015	$0.13539	$0.32439	$0.16261	$0.07061	$0.10829	$0.09244
2/1/2015	$0.13539	$0.32439	$0.16261	$0.07061	$0.10829	$0.09244
5/1/2015	$0.13539	$0.32439	$0.16261	$0.07061	$0.10829	$0.09244
11/1/2015	$0.13286	$0.33063	$0.16574	$0.06929	$0.10626	$0.09071
8/1/2016	$0.12254	$0.29931	$0.15004	$0.06391	$0.09801	$0.08366

Table G-8: Schedule DG-R, Distributed Generation Renewable - Time Metered, Secondary Voltage

Secondary Voltage						
	Summer			Winter		
Effective Date	Off Peak	On Peak	Semi Peak	Off Peak	On Peak	Semi Peak
9/1/2012	$0.05078	$0.13950	$0.07018	$0.05603	$0.08556	$0.07520
1/1/2013	$0.05668	$0.15508	$0.07802	$0.06255	$0.09550	$0.08394
9/1/2013	$0.05958	$0.16042	$0.08071	$0.06575	$0.10039	$0.08823
12/1/2013	$0.05884	$0.15849	$0.07973	$0.06494	$0.09915	$0.08714
1/1/2014	$0.06388	$0.17179	$0.08643	$0.07050	$0.10765	$0.09461
4/4/2014	$0.05748	$0.15531	$0.07814	$0.06343	$0.09686	$0.08513
5/1/2014	$0.06862	$0.18472	$0.09293	$0.07573	$0.11563	$0.10162
8/1/2014	$0.12175	$0.29516	$0.14814	$0.06359	$0.09767	$0.08334
1/1/2015	$0.14108	$0.34147	$0.17139	$0.07369	$0.11318	$0.09657
2/1/2015	$0.13568	$0.32499	$0.16311	$0.07085	$0.10882	$0.09285
5/1/2015	$0.13314	$0.33124	$0.16625	$0.06953	$0.10679	$0.09111
11/1/2015	$0.13406	$0.33344	$0.16735	$0.07001	$0.10752	$0.09174
8/1/2016	$0.12280	$0.29986	$0.15050	$0.06412	$0.09849	$0.08403

Table G-9: Schedule DG-R, Distributed Generation Renewable - Time Metered, Transmission Voltage

Transmission Voltage						
	Summer			Winter		
Effective Date	Off Peak	On Peak	Semi Peak	Off Peak	On Peak	Semi Peak
7/1/2012	$0.04917	$0.13670	$0.06795	$0.05426	$0.08290	$0.07282
9/1/2012	$0.05489	$0.15198	$0.07555	$0.06057	$0.09253	$0.08128
1/1/2013	$0.05770	$0.15721	$0.07815	$0.06367	$0.09726	$0.08544
9/1/2013	$0.05698	$0.15531	$0.07720	$0.06288	$0.09606	$0.08439
12/1/2013	$0.06187	$0.16835	$0.08369	$0.06827	$0.10429	$0.09162
1/1/2014	$0.05567	$0.15220	$0.07566	$0.06143	$0.09384	$0.08244
4/4/2014	$0.06645	$0.18102	$0.08998	$0.07333	$0.11203	$0.09841
5/1/2014	$0.11862	$0.28997	$0.14360	$0.06082	$0.09302	$0.07952
8/1/2014	$0.13745	$0.33547	$0.16613	$0.07048	$0.10778	$0.09215
1/1/2015	$0.13219	$0.31929	$0.15811	$0.06776	$0.10363	$0.08860
2/1/2015	$0.13219	$0.31929	$0.15811	$0.06776	$0.10363	$0.08860
5/1/2015	$0.13219	$0.31929	$0.15811	$0.06776	$0.10363	$0.08860
11/1/2015	$0.12972	$0.32543	$0.16115	$0.06650	$0.10169	$0.08694
8/1/2016	$0.11964	$0.29460	$0.14589	$0.06133	$0.09379	$0.08019

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APPENDIX H

REFERENCE DOCUMENTS

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APPENDIX H

REFERENCE DOCUMENTS

STATE OF CALIFORNIA

1. Assembly Bill 1890, Chapter 856: http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_cfa_20020625_115107_sen_comm.html
    a. Authorizes retail competition within investor-owned utility (IOU) service areas (direct access).
    b. Authorizes marketers, public agencies, cities, counties, and special districts to offer electric service to customers aggregated on a voluntary basis, provided that each customer in their jurisdiction agrees to participate by a positive written declaration (community aggregation).
2. Assembly Bill 1X Chapter 4: http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0001-0050/abx1_1_bill_20010201_chaptered.pdf
    a. Suspends the right of retail customers of IOUs to acquire electric power service from non-IOU providers until the Department of Water Resources (DWR) no longer supplies power to IOU customers.
    b. Pursuant to AB 1X, the CPUC has suspended direct access as of September 20, 2001.
3. Assembly Bill 80 (April, 2002): http://leginfo.ca.gov/pub/01-02/bill/asm/ab_0051-0100/ab_80_cfa_20020829_030636_asm_floor.html
    a. Establishes an exemption from the direct access suspension which would authorize two cities (Cerritos and San Marcos) in SCE's service area to act as community aggregators and provide direct access service to their residents.
4. Assembly Bill 1169 (July, 2003): ftp://leginfo.ca.gov/pub/03-04/bill/asm/ab_1151-1200/ab_1169_cfa_20030706_170501_sen_comm.html
5. Modifies the statute enacted by AB 80 to limit its application to one city (Cerritos), to permit Cerritos to offer direct access service to specified school facilities outside its jurisdiction, and to provide that the statute doesn't require Cerritos to rely solely on output of the Magnolia power plant.
6. Assembly Bill No. 117 Chapter 838: http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_bill_20020924_chaptered.html
    a. Amends Sections 218.3, 366, 394, and 394.25 and added Sections 331.1, 366.2, and 381.1 to the Public Utilities Code thereby establishing the CCA option.
    b. PDF copy of the bill: http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_bill_20020924_chaptered.pdf
7. Senate Bill No. 695, Chapter 337 (October 2009): ftp://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0651-0700/sb_695_bill_20091011_chaptered.html
    a. Allows new Non-Residential customers to take direct access service from an Electric Service Provider.

8. California Proposition 16 (2010): DEFEATED constitutional amendment that would have required a two-thirds vote of the electorate before a public agency could utilize public funds for electric service. http://en.wikipedia.org/wiki/California_Proposition_16_%282010%29
9. CPUC's CCA Information page: http://www.cpuc.ca.gov/general.aspx?id=2567

SDG&E CCA INFORMATION

1. SDG&E Rules: http://regarchive.sdge.com/tm2/ssi/inc_elec_rules.html
2. SDG&E Miscellaneous Tariffs: https://www.sdge.com/rates-regulations/current-and-effective-tariffs/electric-tariff-book-miscellaneous-rates

EXISTING AND PAST CCA ACTIVITY

Currently Active CCA's

1. Marin Clean Energy (Formerly Marin Energy Authority): https://www.mcecleanenergy.org
    a. Joint Powers Agreement: http://marin.granicus.com/MetaViewer.php?view_id=36&clip_id=3449&meta_id=366049
        i. City of Belvedere
        ii. Town of Corte Madera
        iii. Town of Fairfax
        iv. City of Larkspur
        v. City of Mill Valley
        vi. City of Novato
        vii. City of Richmond
        viii. Town of Ross
        ix. Town of San Anselmo
        x. City of San Rafael
        xi. City of Sausalito
        xii. Town of Tiburon
        xiii. County of Marin
    b. Ordinances: https://www.mcecleanenergy.org/wp-content/uploads/ordinances.pdf
    c. Operating Rules & Regulations:

        https://www.mcecleanenergy.org/wp-content/uploads/operating-rules-regulations-asammended.pdf
    d. 2012 Integrated Resource Plan:
    e. http://www.leanenergyus.org/wp-content/uploads/2013/10/Marin.2012_Integrated_Resource_Plan.pdf

   f. MCE Implementation Plan (October 2012):

   g. https://www.mcecleanenergy.org/wp-content/uploads/2016/06/Addendum-No.-4-to-the-MCE-Revised-CCA-I-Plan-and-SOI-24-Communities.pdf

   h. Certification from the California Public Utilities Commission (September 2012): http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5875

2. Sonoma Clean Power: http://www.sonomacleanpower.org/ - A new CCA modeled on the Marin Energy Authority with the planned Phase 1 enrollment notices to be sent in February 2014. Like MCE, this CCA is focused on delivering a high percentage (options for 50% and 100%) of renewable energy.

   a. Joint Powers Agreement:

      https://sonomacleanpower.org/wp-content/uploads/2015/01/SCPA-Second-Amended-Joint-Powers-Agreement-Approved-7-25-13.pdf

      i. City of Cotati

      ii. City of Santa Rosa

      iii. City of Sebastopol

      iv. City of Sonoma

      v. Sonoma Country/SCWA

      vi. Town of Windsor

   b. Implementation Plan:

      https://sonomacleanpower.org/wp-content/uploads/2015/01/2015-SCP-Implementation-Plan.pdf

   c. feasibility study: http://www.scwa.ca.gov/files/docs/carbon-free-water/cca/CCA%20Feasibility%20Report%20101211.pdf

3. Community Aggregation Cerritos

   a. While not a CCA, Assembly Bill 80 allowed San Diego CCA of Cerritos to act as an Electricity Service Provider (ESP) which became a template for the subsequent AB 117 establishing CCA.

   b. CPUC Decision 10-01-012 Determining San Diego CCA of Cerritos' Rights Under Assembly Bill 80: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/112848.PDF

   c. Cerritos Magnolia Power Plant – Electric Provider: http://www.cerritos.us/NEWS_INFO/green_cerritos/current_green_efforts/energy_efficiency.php

   d. Cerritos Magnolia Power Project: http://www.cerritos.us/GOVERNMENT/city_organization/departments/water_and_power/magnolia_power_project.php

4. CleanPowerSF (http://cleanpowersf.org/) - This program is in the initial stages of enrollment after numerous politically motivated delays. The program's website is transitioning to the SF

Public Utilities Commission and few reference documents are publicly available as of this writing.

   a. Business Plan and Risk Assessment: https://www.mcecleanenergy.org/wp-content/uploads/2016/01/CleanPowerSF-Business-Plan.pdf

   b. CPUC Implementation Plan certification:

      i. May 2010: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5790

      ii. June 2013: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5773

      iii. August 2015: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5769

5. Lancaster Community Choice Aggregation (http://www.lancasterchoiceenergy.com/) – CCA was rolled out to all municipal accounts in May, 2015 and citywide in October 2015. Lancaster has the goal to become the nation's first net-zero city.

   a. Initial Feasibility Report (August 2013) - http://www.lancasterchoiceenergy.com/wp-content/uploads/2016/11/City-of-Lancaster-CCA-Initial-Feasibility-Report-August-2013-1.pdf

   b. Implementation Plan (February 2015) - http://www.cityoflancasterca.org/home/showdocument?id=24349

Explored or Exploring CCA (have not filed documents with CPUC)

1. City of Victorville: http://www.ci.victorville.ca.us/site/popup.aspx?id=2768

2. San Diego Energy District Foundation: http://www.sandiegoenergydistrict.org/index.html

3. City of Davis: http://cityofdavis.org/city-hall/community-development-and-sustainability/sustainability-program/community-choice-energy

4. City of Chula Vista:

   a. Deal set to end power fight between Chula Vista, SDG&E: http://www.sandiegouniontribune.com/sdut-chula-vista-sdge-sign-10-year-utility-contract-2004oct13-story.html

5. City of San Jose (2011): http://www3.sanjoseca.gov/clerk/Agenda/20111004/20111004_0701.pdf

6. East Bay Municipal Utility District (EBMUD):

   Article on decision to not pursue CCA: http://www.mercurynews.com/2012/12/13/berkeley-advocates-disappointed-as-ebmud-drowns-community-choice-2/

7. City of Berkeley: http://www.ci.berkeley.ca.us/communitychoice/

   a. Base Case Feasibility Evaluation (2005): http://www.ci.berkeley.ca.us/uploadedFiles/Planning_and_Development/Level_3_-_Energy_and_Sustainable_Development/Base%20Case%20Feasibilty%20Evaluation,%20Berkeley.pdf

b. City of Albany (2012): www.albanyca.org/Modules/ShowDocument.aspx?documentid=22194

Suspended CCA

San Joaquin Valley Power Authority – First active CCA in California with service commencing in May, 2010.

a. CPUC authorization (April 2007) - http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5882

CCA RESEARCH

1. Public Interest Energy Research (PIER) Program - Community Choice Aggregation Pilot Project - http://www.energy.ca.gov/2009publications/CEC-500-2009-003/CEC-500-2009-003.PDF
    a. Assisted twelve California communities in their investigation of Community Choice Aggregation (CCA) feasibility:
        i. Berkeley:
        ii. Beverly Hills: http://www.beverlyhills.org/cbhfiles/storage/files/filebank/2572--GP-TBR-Chp-3-3-3-4-3-5.pdf
        iii. Emeryville
        iv. Los Angeles County
        v. Marin County
        vi. Oakland
        vii. Pleasanton
        viii. Richmond
        ix. San Diego County
        x. San Marcos
        xi. Vallejo
        xii. West Hollywood
    b. Independent peer review of Navigant Consulting's Community Choice Aggregation Feasibility Studies: http://nature.berkeley.edu/classes/es196/projects/2010final/FaulknerK_2010.pdf
    c. Final Report: http://www.energy.ca.gov/2008publications/CEC-500-2008-091/CEC-500-2008-091.PDF
    d. Appendix A: Roadmap for Renewable Energy Development Procurement, publication # CEC-500-2008-091-APA: http://www.energy.ca.gov/2008publications/CEC-500-2008-091/CEC-500-2008-091-APA.PDF
    e. Appendix B: Project Reports on California Public Utilities Commission Decisions on Community Choice Aggregation, publication # CEC-500-2008-091-APB: http://www.energy.ca.gov/2008publications/CEC-500-2008-091/CEC-500-2008-091-APB.PDF

e. Appendix B: Project Reports on California Public Utilities Commission Decisions on Community Choice Aggregation, publication # CEC-500-2008-091-APB: http://www.energy.ca.gov/2008publications/CEC-500-2008-091/CEC-500-2008-091-APB.PDF

f. Appendix C: Sample Data Request Letters from Local Governments to Investor-Owned Utilities, publication # CEC-500-2008-091-APC: http://www.energy.ca.gov/2008publications/CEC-500-2008-091/CEC-500-2008-091-APC.PDF

g. Appendix D: Key Assumptions Used in the Base Case Feasibility Reports, publication # CEC-500-2008-091-APD: http://www.energy.ca.gov/2008publications/CEC-500-2008-091/CEC-500-2008-091-APD.PDF

h. Appendix E: Community Choice Aggregation Implementation Plan Template, publication # CEC-500-2008-091-APE: http://www.energy.ca.gov/2008publications/CEC-500-2008-091/CEC-500-2008-091-APE.PDF

i. Appendix F: Community Choice Aggregation Fact Sheet, publication # CEC-500-2006-082. Published August 2006, republished April 2009: http://www.energy.ca.gov/2006publications/CEC-500-2006-082/CEC-500-2006-082.PDF

j. Appendix G: Community Choice Aggregation Guidebook, publication # CEC-500-2009-003: http://www.energy.ca.gov/2009publications/CEC-500-2009-003/CEC-500-2009-003.PDF

k. Appendix H: Berkeley, Emeryville, Oakland Business Plan, publication # CEC-500-2008-091-APH: http://www.energy.ca.gov/2008publications/CEC-500-2008-091/CEC-500-2008-091-APH.PDF

CPUC REQUIREMENTS

Table H-1 lists the detailed CPUC requirements for establishing a CCA in the state of California. Requirements include developing an implementation plan, preparing a Statement of Intent, registering the implementation plan with the CPUC, providing evidence of a bond, and ensuring resource adequacy.

Table H-1: CPUC Requirements for CCAs

Requirement	Note
Develop an implementation plan • An organizational structure of the program, its operations, and its funding • Rate setting and other costs to participants • Provisions for disclosure and due process in setting rates and allocating costs among participants • The methods for entering and terminating agreements with other entities • The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures • Termination of the program • A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities	A CCA shall develop an Implementation Plan, as defined in PU Code Section 366.2(c)(3)
Prepare a Statement of Intent providing for the following: • Universal access • Reliability • Equitable treatment of all classes of customers • Any requirements established by state law or by the Commission concerning aggregated service	
Register and file an implementation plan with the CPUC	Within 90 days after the Community Choice Aggregator establishing load aggregation files its implementation plan, the Commission is required to certify that it has received the implementation plan, including any additional information necessary to determine a cost recovery mechanism

Requirement	Note
Provide evidence of Bond/Insurance	Pursuant to Resolution-E-4133, the Commission adopted an interim bond amount of $100,000 (or that amount in cash) that CCAs shall post with the Commission as part of their registration packet pursuant to Decision 05-12-041
Ensure resource adequacy	

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