Redwood Coast Energy Authority Technical Study

October 10, 2016

CONTENTS

1 Executive Summary

The purpose of the Redwood Coast Energy Authority (RCEA) Technical Study is to assess whether Community Choice Aggregation (CCA) is feasible for Humboldt County and its local communities. The major findings of this Study are summarized below.

A Humboldt County CCA is Feasible

The study examined a variety of scenarios under expected and adverse conditions. In all cases, CCA was financially viable under a reasonable range of assumptions. The scenarios examined were explicitly chosen to assess feasibility while achieving the community's energy goals as identified through a variety of methods including:

- The RePower Humboldt Strategic Plan
- Work by RCEA and its Board of Directors
- Public engagement at a number of forums

Financial feasibility was defined to ensure that the CCA should remain solvent, with sufficient financial reserves, even under the most adverse outcomes studied, while maintaining rate competitiveness with PG&E.

Supporting Local Renewable Generation

A key goal for the prospective CCA is to support and develop local renewable generation. This has a number of benefits.

- ***Economic*** – Support local economic activity by preserving and providing jobs and benefits to County residents
- ***Environmental*** – Improve environmental stewardship through use of cleaner energy sources with lower greenhouse gas emissions
- ***Reliability*** – Increase reliability by developing additional local generation in Humboldt County to decrease the chance of loss of power under stressed conditions on the grid.

The scenarios analyzed included varying amounts of local renewable generation from:

- *Biomass*
- *Community Solar*
- *Local Hydro*
- *Rooftop Solar*

A CCA would also be able to develop local *wind* generation plus other sources of supply that may become economically viable in the future such as *offshore wind* and *tidal* generation.

Local Control to Realize Energy Goals

A key benefit of establishing a CCA, which has been a motivator for CCAs that have already been established in California and elsewhere, is local control of energy investments. The community, via its elected representatives who sit on the RCEA's board of directors, will be able to direct funds from electric customers' payments toward areas of priority for the local community. This may include local renewable generation, as discussed above, as well as other areas that are considered important such as:

- *Energy Efficiency*
- *Electric Vehicle infrastructure*
- *Incentives for Distributed Generation*
- *Demand Response Programs*
- *Energy Innovation Funding*

Additional Customer Benefits

CCAs in California are "opt-out" programs. This means that any customer can choose to opt-out of the program at start-up or at any time thereafter. It will therefore be important that the CCA be focused on meeting the needs of its customers. This will take the form of pursuing local energy goals and also providing competitive electricity rates to customers. All of the scenarios examined include *rate savings* relative to PG&E's forecasted rates.

Risks of Operating a CCA

While there are many benefits to a CCA, there are also risks that need to be identified, monitored and mitigated. The primary risks are associated with power supply procurement and legal/regulatory changes. Electricity markets can exhibit volatile prices causing the cost of supply to potentially change unexpectedly. Additionally, a counterparty may fail to fulfill its obligations. Regulatory charges such as an unexpected increase in the Power Charge Indifference Adjustment (PCIA) charge may increase the CCA rates to an uncompetitive level.

If the CCA's rates become significantly higher than PG&E's, there is a risk that customers may revert to PG&E service, which could potentially threaten the CCA's financial viability. It will therefore be important for the CCA to follow sound, industry best practices including:

- ***Financial Reserves*** – Building financial reserves as a buffer against unexpected cost increases
- ***Risk Management*** – Performing prudent risk management, including spreading procurement over time, across counterparties and among different generation technologies
- ***Qualified Staff*** – Employing competent and experienced staff and third-party service providers
- ***Industry Coordination*** – Coordinating with CCAs and other interested parties to understand and influence legislative and regulatory decisions

While there are significant risks to operating a CCA, RCEA should be able to successfully manage these risks as other CCAs and many other publically owned utilities have done for many years.

2 Overview

2.1 Introduction

The Humboldt County CCA Technical Study assesses the feasibility of implementing and operating a Community Choice Aggregation (CCA) program within Humboldt County. A CCA becomes the electricity supplier for residents and businesses within the sponsoring jurisdictions, taking over that role from the incumbent utility (PG&E for Humboldt), unless the customer "opts-out" of the CCA program and remains a bundled service customer of PG&E. The number of California communities pursuing CCAs is poised to grow dramatically over the next several years. CCAs allow communities to take ownership of their electricity futures to achieve economic, environmental and other community benefits.

2.2 Local CCA's Roots in RePower Humboldt

The current effort to develop a Community Choice Aggregation program within Humboldt County grew out of an earlier effort – RePower Humboldt – which performed an exhaustive analysis of the prospects for developing local sources of electricity and laid out a vision for Humboldt to achieve its energy goals. Some of the key findings from that report that are especially relevant to a prospective CCA are[1]:

- *A renewable energy future is feasible.*
- *A RePower Humboldt future will have beneficial economic, security, and environmental impacts.*
- *Energy efficiency is our cheapest option and should be maximized.*
- *Biomass, wind and small hydro can play a significant supply side role.*
- *Distributed generation can play an important role, but utility-scale generation continues to be necessary.*
- *A mix of power options is needed and all options have impacts, including the "do nothing" option.*

The ability to stand-up a CCA is an opportunity for Humboldt County to further many of these goals. Through community ownership of the provision of electricity the local community can determine:

- What type of generation sources to contract with;
- What type, whether and where to develop new generation resources;
- How to support local residents and businesses in developing their own energy sources;

[1] http://www.redwoodenergy.org/images/RESCO/RePower_Humboldt_Strategic_Plan_FINAL_2013-04-17.pdf

- How best to support the local economy by directing customers' electricity spending towards local suppliers and businesses; and
- How to provide ratepayer savings.

2.3 Community Choice Aggregation

A CCA becomes the local electric generation supplier while the transmission and distribution of electricity remains the responsibility of PG&E. Humboldt County and a number of the local communities within Humboldt County have tasked the Redwood Coast Energy Authority (RCEA) – a local Joint Powers Agency already focused on local energy issues – with assessing, implementing and eventually running a CCA.

While the CCA will be a new endeavor for Humboldt County, it is a proven model which has been highly successful in a number of other cities and counties where it has been implemented. MCE (Marin Clean Energy, now service multiple communities outside of Marin County) was the first CCA in California and has been operational and growing for the last six years. Sonoma Clean Power, Lancaster Choice Energy, and most recently CleanPowerSF (serving San Francisco) are all successfully implementing their local communities' energy goals. Efforts are currently underway in over 15 additional California communities interested in starting or joining existing CCAs.

The conditions for beginning a CCA are very favorable. Electricity supply costs have declined significantly over the last several years. A new CCA can enter the business with relatively low costs for generation and therefore be rate competitive with PG&E. In particular, as renewable energy costs have declined, CCAs have been able to build greener supply portfolios, with lower GHG emission factors, than PG&E and, at the same time, provide rate savings for their customers while also investing in local energy priorities.

2.4 Implementation

The typical process for implementing a CCA, and the path chosen by Humboldt, consists of a series of steps. These steps are:

- Determine the feasibility of a CCA through a technical study (this report)
- Approve CCA-enabling revisions to the RCEA joint power agreement (JPA) that enable RCEA to become the CCA in Humboldt County for interested member agencies
- Adopt an ordinance by each local government governing body proclaiming their decision to participate in the CCA through RCEA
- Develop an implementation plan which must be submitted to the California Public Utilities Commission (CPUC) for certification
- Contract with third-party service and power supply providers
- Align RCEA's organization chart and staffing plans with the requirements of CCA operations
- Transition service from the existing utility, including marketing the new service, sending opt-out notices to prospective customers, and submitting requests to transfer accounts from PG&E to RCEA
- Procure and supply energy to customers and operate the new CCA

RCEA made the determination to combine a number of these steps within a single RFP process. RCEA issued a request for companies to perform the technical study, develop the implementation plan, assist in marketing and community outreach, and provide on-going services for managing wholesale electricity procurement and retail customer relationship management and billing. Through that request, RCEA selected a consortium of three companies to assist RCEA in implementing its CCA.

The Energy Authority (TEA) was selected to perform the technical study, develop the implementation plan, and then assist with wholesale market services on an on-going basis. TEA is a not-for-profit corporation owned by eight municipal and state-chartered power agencies that provides wholesale energy services to over forty energy companies across the United States.

Noble Americas Energy Solutions was selected to provide systems and services to support billing and customer engagement for RCEA's customers Noble serves a similar role for all of the other, existing CCAs in California. RCEA chose LEAN Energy, a not-for-profit CCA advocacy group, to provide marketing, outreach, and program development services. LEAN has worked with many existing and prospective CCAs.

The plan is for the CCA to begin serving customers in the second quarter of 2017. In order to make that timeline the following interim milestones have been set (see Section 10 for more detail).

- Draft Technical Study (this report) – *July, 2016*
- Final Technical Study – *August, 2016*
- Implementation Plan – *4th Quarter, 2016*
- Community Outreach – *Ongoing*
- Staff Hiring – *Ongoing*
- Initial Energy Procurement Decisions – *4th Quarter, 2016*
- First Customer Opt-out Notices Sent – *Feb, 2017*
- Second Customer Opt-out Notices Sent – *Mar, 2017*
- Begin Service to CCA Customers – *2nd Quarter, 2017*

The technical study is intended to answer the question of whether a Humboldt County CCA will be able to achieve the local economic and environmental goals while also being financially viable. The study was developed by TEA in collaboration with RCEA staff, with support from the RCEA board of directors and engagement with local stakeholders. The study analyzes the financial performance of a CCA under a number of scenarios for CCA participation rates and supply portfolios and under different cases for energy and regulatory costs.

2.5 Humboldt Energy Goals

The RePower Humboldt Study, and subsequent direction from the RCEA Board with feedback from the local community, has identified a number of objectives related to energy which a CCA should be capable of supporting. These objectives are:

Local Energy Independence

Due to its relative remoteness from the rest of California the North Coast is somewhat of an island within the larger electrical system, with a fairly narrow transmission bridge connecting it to the "electrical mainland". With a peak load of approximately 170 MW, it's only possible to transmit approximately 70 MW from outside of the region. Until recently, approximately 30 percent of Humboldt County's power was supplied by local biomass-fired and small hydroelectric generators. PG&E's natural gas-fired Humboldt Bay Power Plant supplied about 50 percent of Humboldt County's power requirements. Recently, however, the amount supplied by local biomass generators has declined considerably as a result of long-term power sales agreements to PG&E expiring.

From an electric reliability perspective, Humboldt is vulnerable to outages of both the lines connecting Humboldt to the outside world and to outages of key generators within the region. Without either of those Humboldt is at risk of having to curtail load and/or experience blackouts. This has led to a desire to support existing local renewable resources, and develop additional ones which are both reliable and environmentally responsible.

Environmental Sustainability

Humboldt County desires to be a responsible steward of the environment. This involves sourcing as much power as is feasible from environmentally friendly and carbon neutral[2] sources such as solar, wind, hydro and biomass. It also means spurring innovation in alternative energy sources which may be particularly suited to the region such as wave and offshore wind generation.

Economic Development

Total spending on electricity within Humboldt County is substantial. Approximately $60 million is spent annually by Humboldt County residents and businesses for electricity supply from PG&E[3]. This is in the same range as what the County of Humboldt collects in property and sales taxes each year, and is of a similar size to the total operating budget for the City of Eureka.

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[2] Zero-net-carbon emitting resources are based upon the definition used by the California Air Resources Board in instituting AB 32 http://www.arb.ca.gov/cc/capandtrade/capandtrade/unofficial_ct_030116.pdf (p 122)

[3] This represents spending just on generation supply. An additional ~$100mm would still flow to PG&E for transmission, distribution and regulatory charges.

Currently, most of this spending flows outside of the county – to the utility and its power suppliers.

It is desirable, from an economic development perspective, to redirect as much of this spending as possible into the local economy. The CCA can accomplish this through a variety of means. The CCA can:

- Procure energy from existing local resources
- Develop new local resources
- Incentivize individual residents and businesses to develop their own supply sources
- Invest in local energy-related programs such as energy efficiency and electric vehicle infrastructure.
- Save ratepayers money on their electricity bills which they can then spend locally.

Ratepayer Savings

For both economic development purposes and for customer satisfaction and long-term viability of the CCA, it is desirable for CCA rates to be lower than comparable PG&E rates. CCA customers can choose at any point to revert back to PG&E service. Therefore it is incumbent upon the CCA, in addition to being more environmentally conscious and supportive of local economic development, to keep costs low and practice sound financial management such that the CCA can afford to offer competitive rates on a consistent basis.

2.6 Study and Results

The purpose of the study is to model CCA supply portfolios and cost structures consistent with its energy goals and to determine whether, and under what circumstances, the CCA is able to achieve these objectives successfully. With consultation from TEA, RCEA identified three different scenarios that are all broadly consistent with the aforementioned goals but which emphasize different aspects of them. The three scenarios are defined in the table below. It is likely that the actual CCA program will differ from these exact scenarios, but the scenarios are representative of plausible outcomes and show that the CCA can be feasible under a variety of operational objectives.

Table 1: Scenario components

Scenarios - Priority	***Scenario 1 - High Biomass***	***Scenario 2 - High Mixed Local Renewables***	***Scenario 3 - High Ratepayer Savings***
Biomass Capacity (MW)	**25**	**20**	**15**
Local Utility-Scale Solar Capacity (MW)	**7**	**15**	**7**
Local Small-Scale and Rooftop Solar (MW)	**4**	**6**	**8**

Local Hydro (MW)	**0**	**2**	**2**
Ratepayer Savings (5 Year, Cumulative)	**$10mm**	**$10mm**	**$15mm**
Local Energy Program Spending (per Year)	**$0mm**	**$0.5mm**	**$1.5mm**

The time horizon for the study is the years 2017-2026. However, throughout the document results are often provided for or through Year 5 (2021) in order to emphasize the more near-term results rather than impacts which might occur in the later years. The supply mix for each scenario after five years is shown in Figure 1.

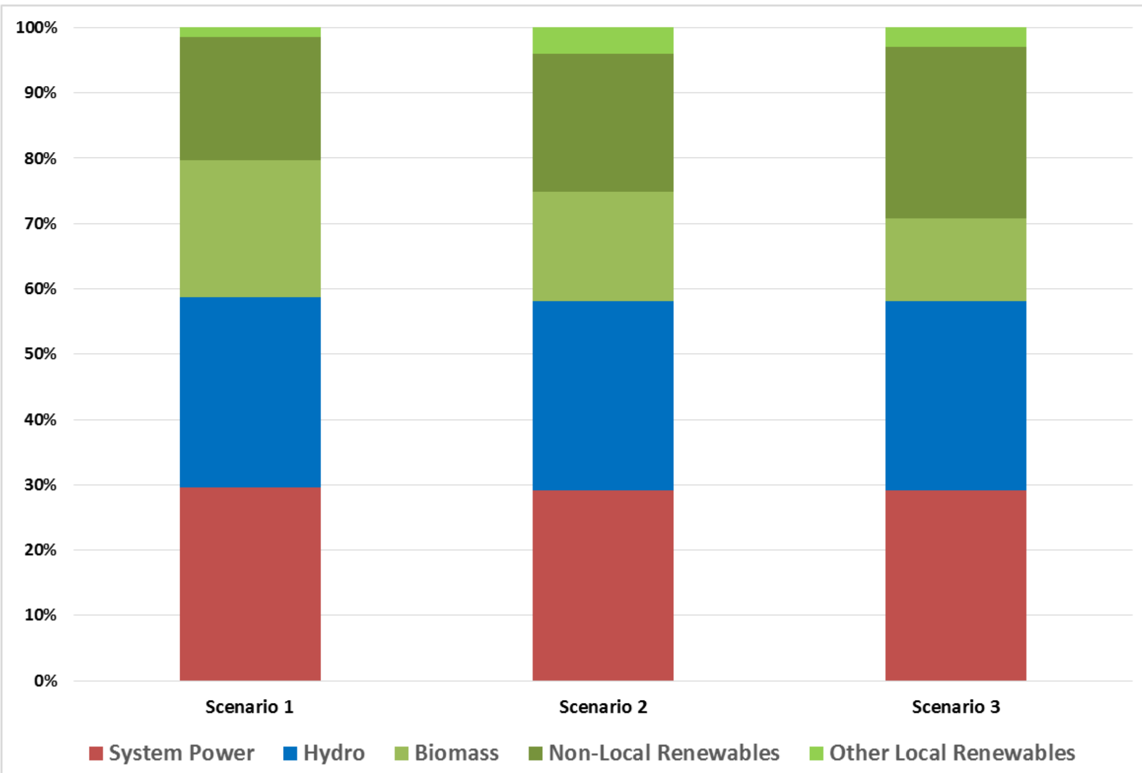

Figure 1: Supply mix for each Scenario in 2021

Common to all of the scenarios are the following goals.

1. **Renewables** – All scenarios exceed the forecasted PG&E California Renewable Portfolio Standard (RPS) percentages by 5% of overall supply
2. **Greenhouse Gas Emissions** (GHG) – All scenarios achieve GHG reductions of 5% compared to PG&E's forecasted GHG emissions.
3. **Financial Reserves** – All scenarios are designed to accumulate at least $8mm (~4% of retail revenue) in financial reserves in the bad case and $16mm (~7% of retail revenue) in financial reserves in the base case.

Figure 2 shows the projected CO_2 emissions in lbs/MWh for the CCA and for PG&E over ten years. This is a cumulative reduction of over 50,000 metric tons of CO_2 emissions over the ten year period, or the equivalent of approximately 1,000 fewer automobiles on the road over that time period.

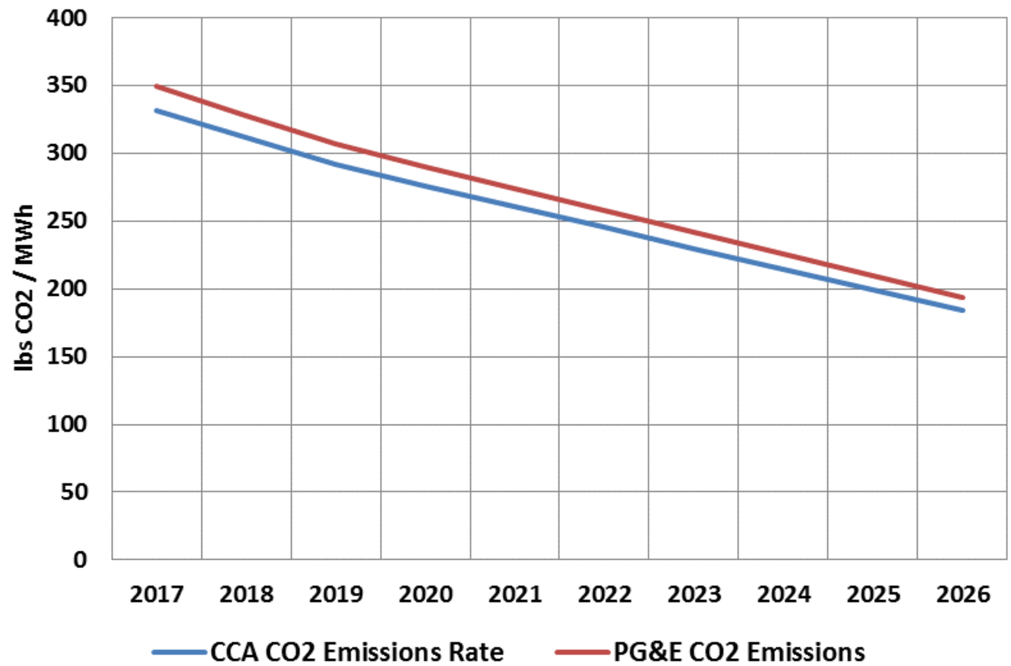

Figure 2: Projected CO2 emissions for the CCA and PG&E (same for all CCA Scenarios)

Under the base case assumptions, as defined below, and under the high (good) and low (bad) case contingency assumptions with reduced reserves requirements, all of the above scenarios were determined to be feasible.

2.7 Base Case and Sensitivity Analysis

The key external drivers of the financial success of the CCA are the cost of the CCA's electricity supply, the level of the regulatory charges that customers who leave PG&E service are charged, and the opt-out rate of potential CCA customers. TEA and RCEA defined base, high (good) and low (bad) cases to simulate the impact of each on the financial outcomes of the CCA.

The financial response to changes in market prices for electricity is a function of the CCA portfolio. The more supply that's procured or built at fixed prices, the less the CCA will be able to take advantage of lower market prices in the future or be adversely impacted by higher market prices. And, because the CCA is competing with PG&E's rates, it is also important how much of PG&E's supply cost is fixed and how much they are exposed to higher or lower market prices for electricity.

The criterion for feasibility for each scenario was that the CCA accumulate financial reserves of at least $8mm (~4% of retail revenues) at the end of five years under the bad case outcome. This was deemed to be a sufficient buffer to allow the CCA enough time to adapt its strategy and cost structure to put itself on firmer financial footing without jeopardizing the solvency of the CCA. Figure 3 shows the projected reserves for Scenario 1 (High Biomass) for the Base, Good and Bad cases.

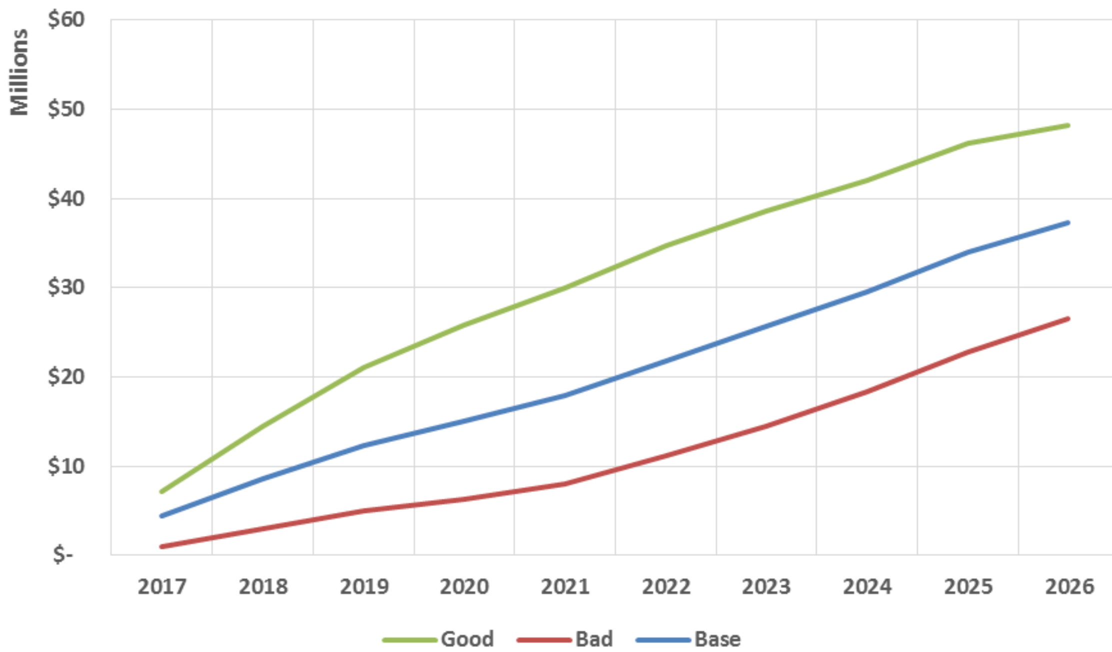

Figure 3: Financial reserves for Scenario 2 (Mixed Local Renewables) for the Base, Good and Bad Cases

2.8 Key Conclusions

Under all cases for all three scenarios the analysis found that the CCA remained feasible. The current electricity market, in spite of a recent increase in energy costs, still remains favorable for new CCA formation. It is anticipated from the analysis that the new RCEA CCA should be able to realize to a substantial degree many of the energy goals that were identified and defined over the course of several years beginning with the RePower Humboldt initiative and continuing through the current CCA formation process. This includes procuring power from existing biomass plants; developing new renewable resources within the county – both at a utility and at a community and individual business and residence level; investing in local energy programs and initiatives; providing ratepayer savings; and developing financial reserves to ensure the long-term viability of the CCA.

3 History of Energy Effort in Humboldt County

Community Choice Aggregation is part of a larger and longer effort within Humboldt County to work towards an energy future with more local control, greater reliance on renewable resources, and increased reliability of the electricity system. A key element in that effort was the RePower Humboldt study which took place from 2009-2013.

3.1.1 Purpose

RePower Humboldt was a collaboration between RCEA, the Schatz Energy Research Center at Humboldt State University, PG&E and the California Energy Commission (CEC). The effort resulted in a report entitled *RePower Humboldt – A Strategic Plan for Renewable Energy Security and Prosperity*[4]. The introduction in the report states:

> *RePower Humboldt is a plan to develop the county's renewable energy resources. We are striving to meet the energy needs of the community and secure our sustainable energy future at minimal costs to energy consumers. Developing local renewable energy resources, including energy efficiency, will provide for energy, economic, and environmental security.*

The vision for the study was summarized as:

> *The RePower Humboldt stakeholder group developed a vision statement for Humboldt County's energy picture in 2030. In that vision Humboldt County is no longer a net importer of energy. The county enjoys a high degree of energy independence through conscientious use of energy conservation and efficiency combined with locally produced and managed renewable energy generation. Significantly more of the money spent on energy stays in the county, supporting more local jobs. Citizens have a diversity of choices for meeting their energy needs and have more local control over energy prices. The county is a thriving research and development center and an incubator for energy technology and related industries. Because citizens, businesses and industries consume modest quantities of energy derived from local renewable sources, life in the county is secure and prosperous.*

The study examined the feasibility and cost to develop a wide variety of renewable energy technologies for local use in the region.

3.1.2 Findings

The findings from the report were:

> *Tremendous community benefits will be realized due to the switch to local renewable energy. Hundreds of new jobs will be created and tens of millions of dollars will be injected into the local economy. Simultaneously, greenhouse gas emissions will be reduced by 33% to 45%*[5]*. In addition, the county will be more energy secure because it won't rely substantially on imports. It will have more control over its local energy resources and prices will stabilize. In summary, key findings from the RePower Humboldt study include:*

- *A renewable energy future is feasible.*

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[4]http://www.redwoodenergy.org/images/RESCO/RePower_Humboldt_Strategic_Plan_FINAL_2013-04-17.pdf

[5] These figures represent reductions from all sources, not exclusively the results from CCA electricity supply substitution.

- *A RePower Humboldt future will have beneficial economic, security, and environmental impacts.*
- *Energy efficiency is our cheapest option and should be maximized.*
- *Biomass, wind and small hydro can play a significant supply side role.*
- *Fuel switching to electric vehicles should play a key role.*
- *Distributed generation can play an important role, but utility-scale generation continues to be necessary.*
- *A mix of power options is needed and all options have impacts, including the "do nothing" option.*
- *The PG&E Humboldt Bay Generating Station provides important energy services and is well suited to support local renewable energy development.*
- *Significant transmission and distribution system upgrades will be necessary to accommodate largescale renewable energy development.*

Many of these findings serve as the motivators to develop a Humboldt County CCA program. The CCA is well positioned to further a number of these goals initially and over the longer term.

3.2 Community Choice Aggregation Opportunity

Community Choice Aggregation aligns very well with the vision set out in the RePower Humboldt report. CCAs were intended as a way for communities to take over their energy supply from the incumbent investor-owned utility.

3.2.1 What is a CCA?

Community Choice Aggregation is a legislatively-enabled process for communities – cities and counties – to take over the role of supplying electricity from the existing electric utility. CCA was established in 2002 by the California legislature in Assembly Bill 117. CCA is an alternative to municipalization of a utility. In municipalization a city takes over the entire electricity system from the utility including the supply and distribution of electricity. This approach has historically been very difficult to accomplish due to high costs and strong opposition from the utilities. Community Choice Aggregation on the other hand has been proven to be relatively low cost, and utilities are prevented by law from opposing the formation of CCAs.

A CCA takes over the role of procuring electricity from generators and providing electricity to its customers. However, the CCA does not physically deliver the energy from the generator to the customer – that service is still provided by the utility. CCA customers pay a single utility bill to their incumbent utility, with portions of the payment going to both the CCA – for the supply portion – and to the existing utility for the transmission and distribution portion. The customer bill will still be issued by the utility, which will then pass along the funds for the energy portion to the CCA. The utility and CCA charges are itemized separately on the bill.

The CCA will determine not only what power sources will supply its customers, but will also:

- Set electricity supply rates
- Administer and contract with external service companies to manage the CCA
- Conduct all relevant regulatory filings and compliance actions

- Determine whether and how to allocate funds for local programs
- Provide customer service and engage in customer outreach and education

A CCA will become a significant presence within the community, with power supply and investment decisions that will affect the local economy and the environmental impact of its customers' electricity consumption.

3.2.2 Other CCAs

There are several CCAs which already operate in California, and many more that are in various stages of starting up. These CCAs have adopted different goals and strategies, however all have been motivated to achieve environmental objectives and provide ratepayer and other economic benefits to their communities.

MCE Clean Energy (formerly Marin Clean Energy) was the first CCA in California and began in 2010 serving approximately ten thousand customers in Marin County[6]. It has continued to add jurisdictions and now serves over 170,000 customers in Marin, Contra Costa and Napa counties. MCE has developed a portfolio with 50% renewable power with plans to become 80% renewable by 2022. While developing a greener portfolio, MCE has also kept its electricity rates below PG&E's and built a reserve fund of $25mm[7].

In addition, MCE has been investing in a variety of innovative local programs. It has become an energy efficiency Program Administrator, receiving funding from the CPUC to administer energy efficiency programs within its service territory. It has developed aggressive net energy metering and feed-in-tariff rates – compensating generators at significantly higher rates than PG&E. MCE is also prototyping a variety of demand response and energy storage programs.

Sonoma Clean Power (SCP) was the second operating CCA in California. It began serving customers in 2014. SCP has made reducing greenhouse gases its top priority and is currently serving its customers with a supply portfolio that is 78% GHG free.

The City of Lancaster began Lancaster Choice Energy in 2015. Lancaster is the first CCA established as an enterprise of a City. Like MCE and SCP it offers a variety of rate plans including the option of 100% renewable power. CleanPowerSF (serving San Francisco) has just recently begun service as the most recent CCA in California.

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[6] https://www.mcecleanenergy.org/wp-content/uploads/2016/01/Marin-Clean-Energy-2015-Integrated-Resource-Plan_FINAL-BOARD-APPROVED.pdf

[7] https://www.mcecleanenergy.org/wp-content/uploads/2016/01/2.3.16-ExCom-Meeting-Packet.pdf

3.2.3 Industry Overview and the Role of CCA

The electricity industry comprises a variety of types of companies which provide different services. Prior to deregulation, the industry consisted of vertical monopolies which supplied essentially all the services required to source and distribute electricity to consumers. Deregulation in the late 1990s broke up the utilities into separate entities – those which supplied electricity and those which transmitted it and distributed it. The supply or generation side of the business was opened to competition. In California the utilities were required to sell off most of their generation assets. The T&D business, however, remained a monopoly business and customers still had to buy their electricity from their local utility.

The retail side of the business has been unevenly opened to competition across the country. In California, there has been a Direct Access option for large electricity customers to purchase electricity from an Energy Service Provider (ESP) rather than the utility, since 1997. There is however a cap on the total load which can be served by Direct Access customers and the program has been fully subscribed.

Community Choice Aggregation offers the only other avenue currently for electricity customers to choose service from an entity other than the local utility. A CCA, like a Direct Access customer, is free to choose which generation sources to procure power from, and to develop the electricity rates and receive the revenue from their customers. However, the utility still has a monopoly on the transmission and distribution of the electricity from the source to the consumer, and will bill the CCA's customers for that service. This feature distinguishes CCAs from traditional municipal utilities which provide the entire generation, transmission and distribution service.

An additional element of the electricity service industry within California (as well as in other regions of the United States) is the existence of the California Independent System Operator (CAISO). While the utilities do still have monopolies over the electric transmission and distribution systems, they have turned over the scheduling of the transmission system to CAISO. CAISO is also responsible for deciding which generators are operating when – based on costs to operate and the need for electric system reliability. CAISO Is also the supplier of last resort and has ultimate responsibility for making sure that the amount of generation in any moment is equal to the amount of load.

CCAs, while they may procure power for specific strategic objectives, and to satisfy certain regulatory requirements, are ultimately able to buy (or sell) whatever incremental electricity need (or surplus) they may have from CAISO. This is another feature that distinguishes CCAs from a traditional municipal utility.

3.2.4 Current Market Conditions

CCAs have become more popular recently in large part because they have been able to provide greener supply to their customers at rates that are similar to or less than utilities' rates. The main reason this is so is because the price of electricity, and specifically the price of renewable generation, has become much cheaper over the last several years. The two main drivers for these trends are the growth of natural gas supplied from fracking of shale, and the decline in the cost of photovoltaic solar generation technologies.

Historically electricity in the United States came from coal fired generators, with natural gas being a typically more expensive, secondary supply source. With the development of fracking that equation has shifted dramatically. Figure 4 shows the growth of natural gas as a supply source, while Figure 5 shows the decline in the price of gas especially since 2008. The threat of federal legislation to limit carbon emissions, and the implementation of carbon emissions penalties in California, have also reduced the willingness of companies to invest in coal generation.

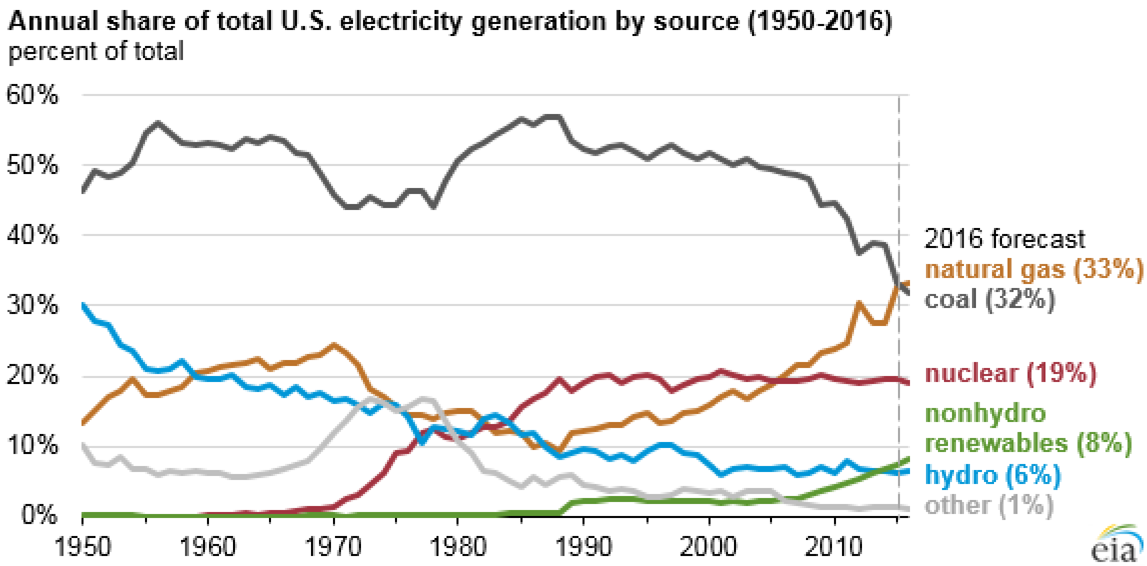

Figure 4: US electricity supply mix [http://www.eia.gov/electricity/]

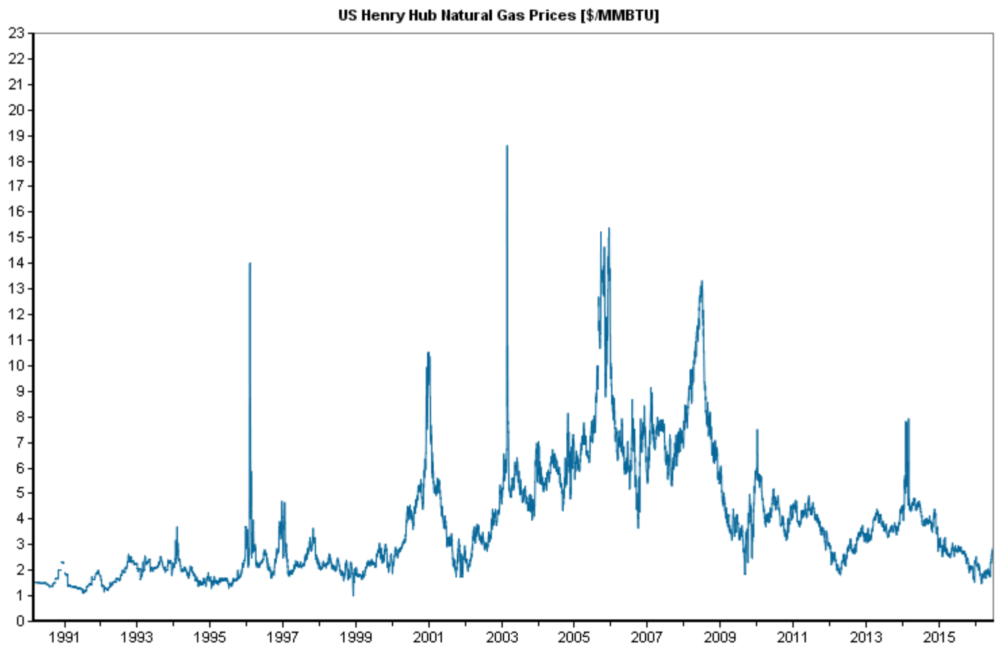

Figure 5: US natural gas prices - Henry Hub spot prices [$/MMBTU]

The decline in the price of photovoltaic technology has been even more dramatic. Figure 6 shows the cost of building solar supply over time. While it is uncertain what will happen to the price of natural gas in the future – recently it has gone up – it is expected that solar prices will continue to decline as the continued increase in renewable portfolio standards around the world leads to continued investment in technological, manufacturing, and development innovation.

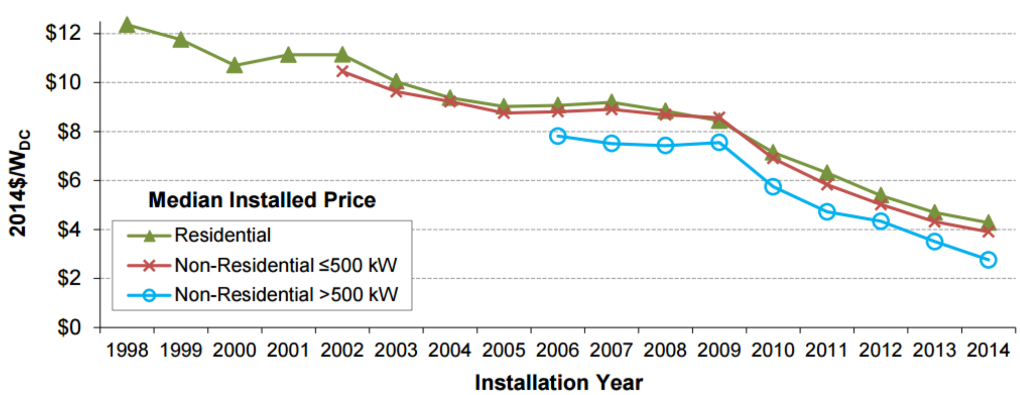

Figure 6: Historical solar generation costs

4 Modeling and Results

The key drivers of the CCA's costs will be the cost of energy supply, the level of regulatory charges on the CCA's customers, and the opt-out rate for potential CCA customers. The cost of supply will be a combination of fixed price energy contracts, CCA-owned assets and the balance of supply that's procured in wholesale electricity markets. The wholesale electricity markets allow CCAs and other electricity entities to buy energy, generation capacity, renewable energy credits, and greenhouse gas allowances under standard contracts over a wide variety of time horizons.

4.1 Supply Cost Assumptions

In order to estimate the costs that the CCA will incur for supply, the analysis incorporated price forecasts for energy, capacity, and renewable energy credits as well as price premiums for zero-GHG supply such as large hydroelectric generation. Prices for energy are based upon prices quoted on the Intercontinental Exchange (ICE) for monthly peak hour (Peak) and off-peak hour (Off-Peak) prices. Those prices are shaped into hourly prices based upon market price simulations using the Aurora XMP production cost model. Monthly around-the-clock prices for electricity for the base, high and low cases are shown in Figure 7. Costs for renewable energy credits, capacity and zero-GHG supply premiums are based upon TEA's experience transacting in the market.

Technology-specific supply costs are estimated from a number of sources. The costs used for biomass and local hydro generation are based upon interviews that were conducted with owners and operators of generators within Humboldt County. Costs for utility-scale solar and wind generation are based upon specific industry reports which are detailed in Section 1. Costs for local solar are based upon the costs for utility-scale solar, scaled by the relative insolation in Humboldt County.

4.2 Prices in Sensitivity Cases

In addition to the expected case, the study analyzed two sensitivity/contingency cases. The bad or poor outcome case occurs with low wholesale energy market prices. While generally lower prices are beneficial to a CCA, allowing it to purchase electricity at a lower price than it might otherwise, once a CCA has already procured supply at a particular price, lower prices may then become adverse to the CCA's finances for a couple of reasons.

1. **Lower prices mean lower PG&E Rates** – lower prices will allow PG&E to procure lower cost supply for the balance of their supply needs beyond their generator costs and long-term purchases.
2. **Lower prices mean higher PCIA** Charges – lower prices also mean that the calculated PCIA rate will be higher since PG&E's fixed supply costs will be even higher than the market price to replace them. (For this reason, TEA recommends that a portion of RCEA's portfolio be procured on a short-term basis as a partial hedge against PCIA rate uncertainty).

The market price curves used for the higher and lower price cases were derived from TEA's proprietary stochastic price model and correspond to 5th and 95th percentile cases. The curves are shown in Figure 7.

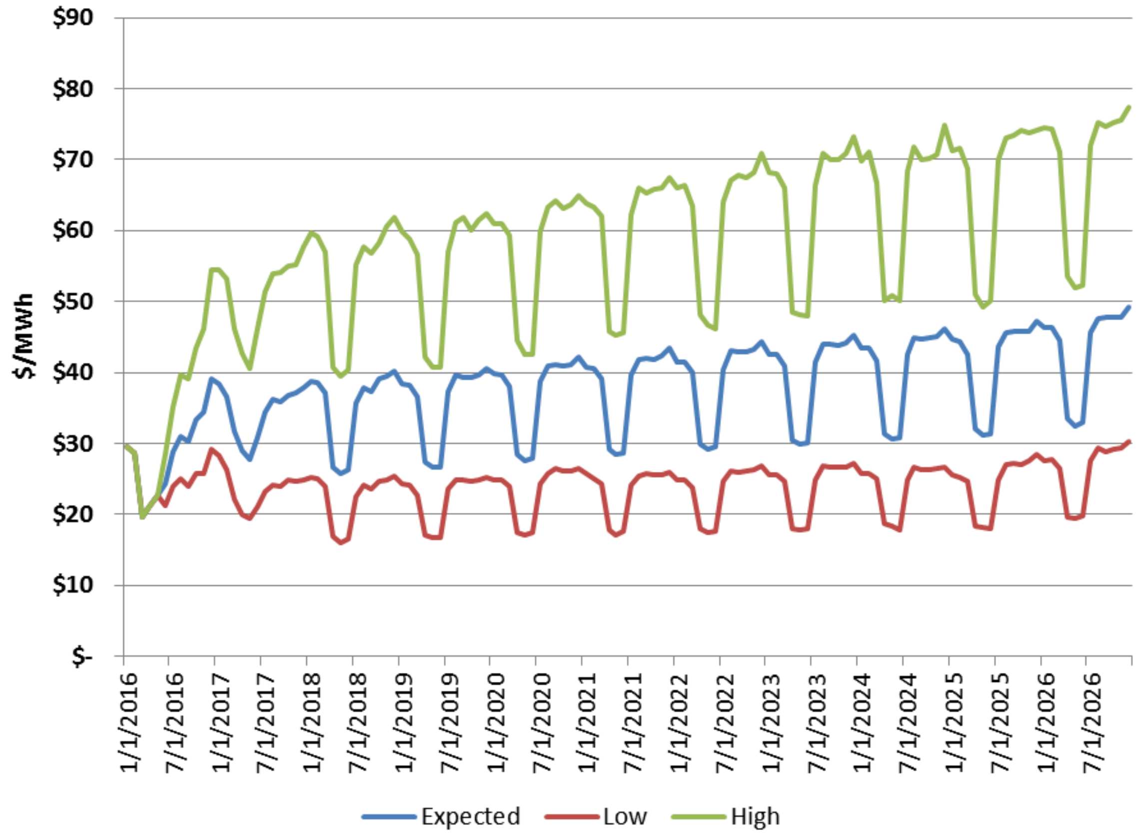

Figure 7: Around-the-clock electricity prices used in the Expected (Base), High (Good) and Low (Bad) Scenarios.

4.3 Regulatory Charge Assumptions

Electricity consumers who depart from PG&E service are charged an ongoing fee called the Power Charge Indifference Adjustment (PCIA) that is intended to compensate the utility for the above-market cost of power supply that was purchased on behalf of the customer that must now be re-marketed. The PCIA considers the cost of supply of PG&E's portfolio compared to the cost to procure power in the current market and assesses a fee on each CCA customer's utility bill designed to reflect the difference. This fee is ongoing, although its magnitude is a function of when they become a CCA customer.

TEA contracted with Mike Bell Consulting to develop a forecast for PCIA rates over time under forecasted market and supply cost assumptions. This forecast was then adjusted based upon the price scenario. Figure 8 shows historical and projected PCIA rates for the three cases.

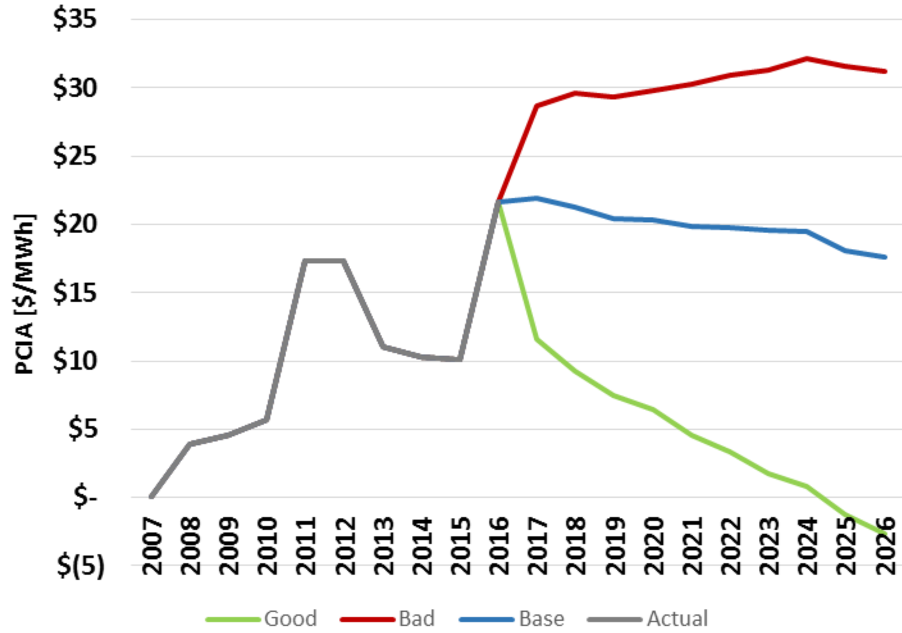

Figure 8: Historical and Projected PCIA Charges for the three cases.

4.4 Opt-out Load Assumptions

Recent CCA opt-out rates for other California CCAs have been 10% or less[8]. For this study it is assumed that no Direct Access load chooses to join the CCA. Direct Access load already is presumed to realize favorable rates and supply options relative to PG&E. These accounts may switch over time if the CCA can convince them that the CCA offers a better alternative, but that is not likely to occur on Day 1. It is also assumed that only the communities which currently have passed or are considering ordinances to join the CCA will participate[9]. These communities represent approximately 99% of the eligible CCA load and are:

- Unincorporated Humboldt County
- City of Eureka
- City of Arcata
- City of Trinidad
- City of Fortuna
- City of Blue Lake

[8] http://napavalleyregister.com/news/local/most-rural-customers-go-with-marin-clean-energy/article_dae7cf6b-c445-55c6-b76d-3d45b6e04648.html; http://www.pressdemocrat.com/news/1859402-181/some-customers-opting-out-of?ref=related; http://www.pressdemocrat.com/news/3983569-181/sonoma-clean-power-becomes-countys?artslide=0;

[9] Rio Dell is currently considering the ordinance to join the CCA.

- City of Rio Dell

In addition, of those communities that do join, it is assumed that 10% of customers, across all rate classes will opt-out of the base case. For the bad outcome case it is assumed 15% of customers opt-out. And for the good outcome case it is assumed only 5% of customers opt-out.

4.5 Local Renewables and Energy Programs

The Humboldt County CCA will have the opportunity, finances permitting, to implement a number of local energy programs. Programs that are explicitly modeled for this analysis include a Feed-in-Tariff (FIT); Net Energy Metering (NEM); and contracting with and developing local renewable supply. It is also anticipated that the CCA will implement or augment other programs such as energy efficiency, demand response, energy storage, and electric vehicle charging.

The model captures each of these areas. A Feed-in-Tariff is a rate that the CCA will pay to local operators of small scale renewable generators that have a total generation capacity of less than 1 MW[10]. The model assumes that these generators will be paid the same as what local utility-scale solar costs which is detailed in Section 8.1. The Net Energy Metering tariff specifies how customers (typically) with rooftop solar will be treated. Their electricity production will be netted against their electricity generation and they will only be charged for the net amount which they use. If they produce more electricity than they consume in a given month, they will be compensated at the CCA-determined NEM rate. Overall, from a budget perspective, the impact of over-generation tends to be small and so only the netting against load is explicitly modeled in the pro-forma analysis.

Contracting with local renewables constitutes a number of different generation types. The most significant source of potential local renewable supply are the three local biomass generators. The analysis does not attempt to distinguish between specific generators. Energy supplied from biomass generators ranges between 12 and 20 percent of RCEA's annual energy requirements depending upon the particular scenario. All biomass generation is assumed to be procured at an initial fixed price of $85/MWh. All of the local renewable supply costs are presumed to include the generation capacity and renewable energy credits from the generators.

Local hydro generation is procured at an initial fixed price of $89/MWh in the model. Local utility-scale solar costs are based upon publically available information about solar procurement costs – scaled to the (low) insolation within Humboldt County, and with a small premium to account for the need for additional local infrastructure and development costs as compared to other locations within California. Local solar costs are presumed to decline over time as has been the case consistently over the last several years. The solar costs are detailed in Section 8.1.

[10] While 1 MW is small relative to a utility-scale solar generator – which can be 500 MW or more – it is about 100 times as large as a typical residential rooftop solar generator.

In addition to the supply costs, there is another bucket to capture the other potential local programs such as energy efficiency, etc. This spending is handled as a single budget item in the amounts shown in Table 1. Longer term supply options, such as offshore wind and tidal generation, are not modeled within this study. The costs and timeline for those resources are uncertain, and outside the time horizon of the study.

4.6 CCA and PG&E Rates

For this study, TEA contracted with Mike Bell to develop rate forecasts for PG&E generation rates for representative rate classes for the ten year time horizon 2017-2026. These forecasts are based on the same price and supply cost assumptions as those used to determine the CCA costs. Information about the methodology used is discussed in Section 8.2. CCA rates are set in the model as a uniform discount to PG&E generation rates across all rate classes in order to achieve the cumulative ratepayer savings targets for each scenario as detailed in Table 1.

4.7 Financial Reserves

A key determinant of the continued success of the CCA will be its ability to accumulate financial reserves. Electricity markets are fundamentally volatile and uncertain. This can lead to unanticipated changes to a CCA's supply costs which may put pressure on CCA rates. Because CCA customers can opt-out at any time to return to PG&E service, it is important that the CCA maintain rates that are competitive with PG&E's. Among other uses, a robust financial reserve can help ameliorate these changes by providing a buffer to absorb unexpected cost increases and prevent the CCA from having to raise rates. Other important uses of financial reserves are as a credit support for wholesale procurement, and eventually, as a source of funding and/or financial security to support long-term generation procurement and investment in future local energy programs.

Within the model the reserve targets are determined in order that, even in the case of a poor outcome in terms of prices and/or opt-out percentages the CCA will maintain a positive reserve balance. The contingent reserve balance is set to be at least $8mm, approximately 4% of retail revenues, at the end of 2021. This corresponds to a reserve balance in the base case of at least $16mm (7% of retail revenue) at the same point in time.

4.8 Administrative Costs

RCEA has chosen to contract with service providers for a large part of the effort involved in running a CCA. These costs are therefore already known and included in the cost analysis. This includes a cost for access to contracts and credits for procuring power. RCEA's internal costs for additional personnel and other expenses are uncertain at this time but are estimated in the Pro Forma as $2mm/year.

4.9 Scenarios

The scenarios were developed in order to represent the range of possible approaches the CCA might take in allocating resources to different sources of supply as well as local programs and rate savings. They are all intended to reflect the broader energy goals outlined in the beginning of the study, although each has a somewhat different emphasis.

The high biomass scenario attempts to maximize the amount of biomass which the CCA can contract for and still achieve its financial objectives. It also includes smaller, but not insignificant amounts of other local renewables including generation supplied through the Feed-in-Tariff and compensated through the Net Energy Metering tariff. There is in addition 7 MW of local utility-scale solar. However, no local hydro or other local program funding is included.

The local renewables scenario emphasizes a diverse supply mix of local renewables and local programs. It has a smaller amount of biomass supply than the high biomass scenario – 20 MW of capacity instead of 25 MW – but increases the amount of local solar (15 MW), local hydro (2 MW), and FIT and NEM assumptions. It also invests $0.5mm/year in other local programs.

The third scenario emphasizes ratepayer savings and investment in local programs over local renewable supply. Biomass capacity is reduced to 15 MW, local utility scale solar is 7 MW, FIT and NEM is assumed to be 6 MW, and local hydro is 2 MW of capacity. Meanwhile, ratepayer savings are increased to $15mm cumulative by 2021 and spending on local programs is increased to $1mm/year.

4.10 Results

The analysis shows that the three scenarios considered are feasible over a five (and ten) year time horizon under the cases considered. In all three scenarios net reserves remain positive even in the bad case, with ratepayer savings throughout the time horizon while achieving the supply objectives.

Figure 9 shows the annual load forecast for the base case scenario in average MW for each rate class. The forecast includes current PG&E bundled customers in the launch communities, but does not include any direct access load. It also assumes a 10% opt-out rate (beyond the Direct Access load). Load is forecast to grow at a 1% annual rate on an expected basis.

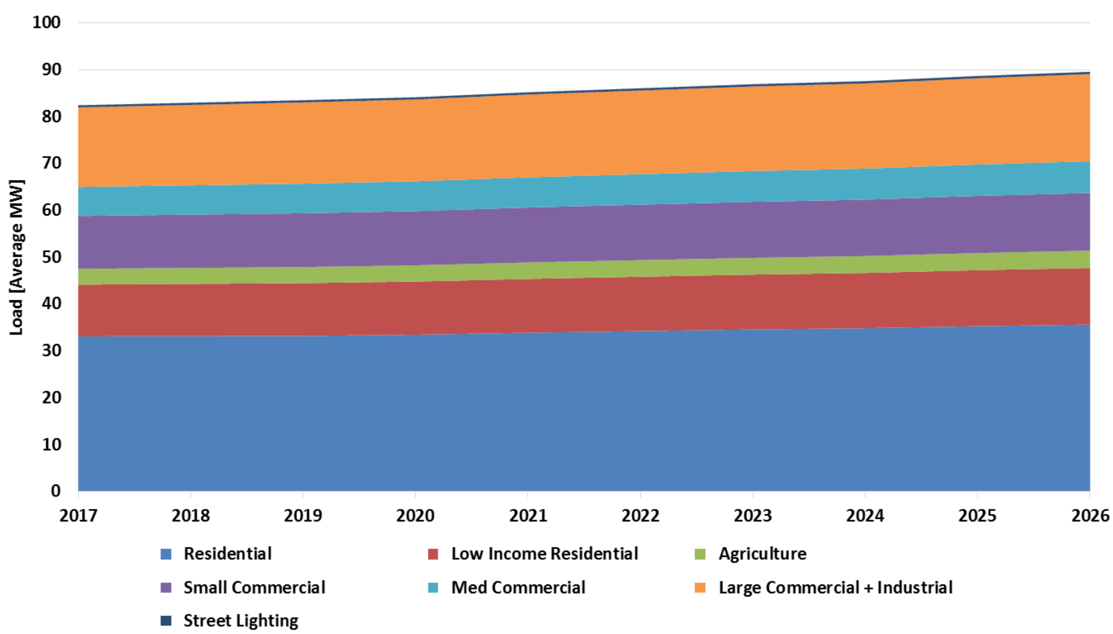

Figure 9: Retail Load Forecast by rate class for Base Case (based on a full year of load for 2017)

Figure 10, Figure 11, and Figure 12 show the supply mixes for each scenario over time in average MW. The supply is for wholesale load which includes the need to account for electrical losses that occur when energy is transmitted. The wholesale load is therefore larger than the retail load displayed in Figure 9.

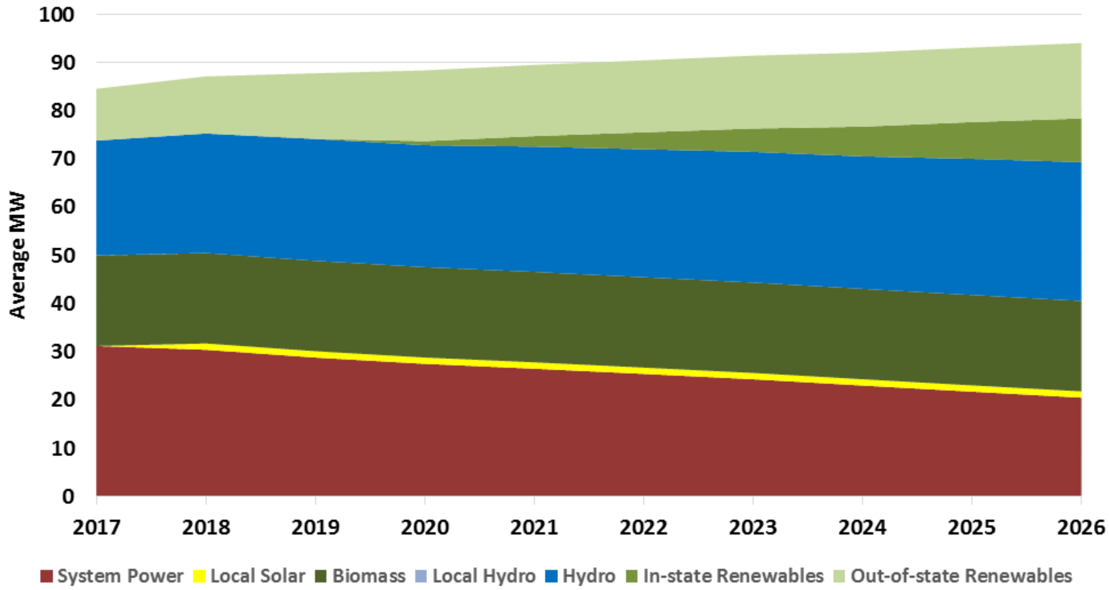

Figure 10: Supply mix through time for the Scenario 1 - High Biomass

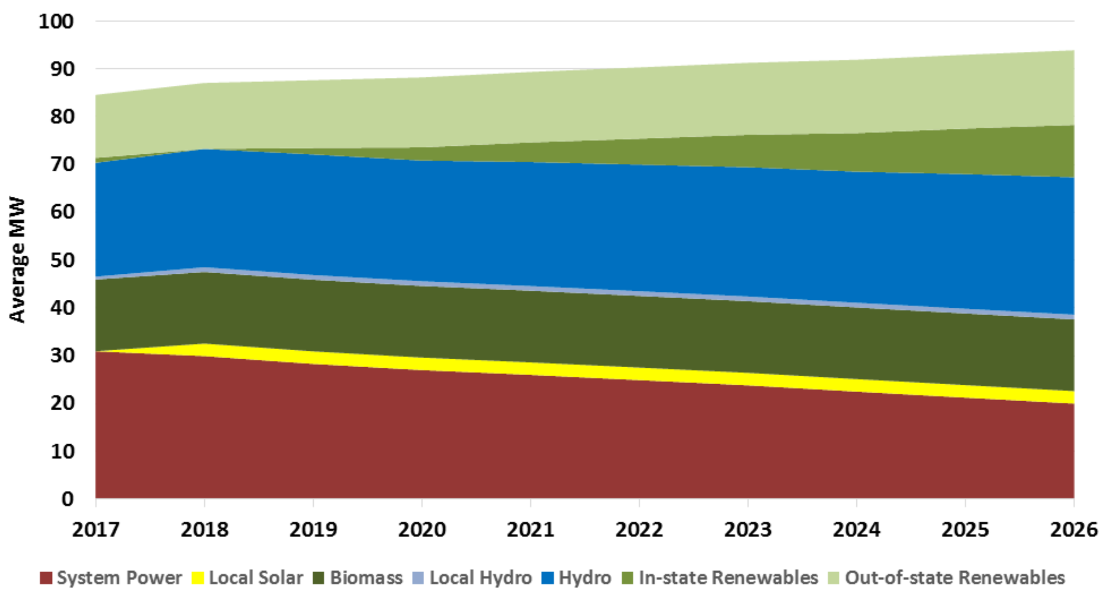

Figure 11: Supply mix for Scenario 2 - Mixed Local Renewables

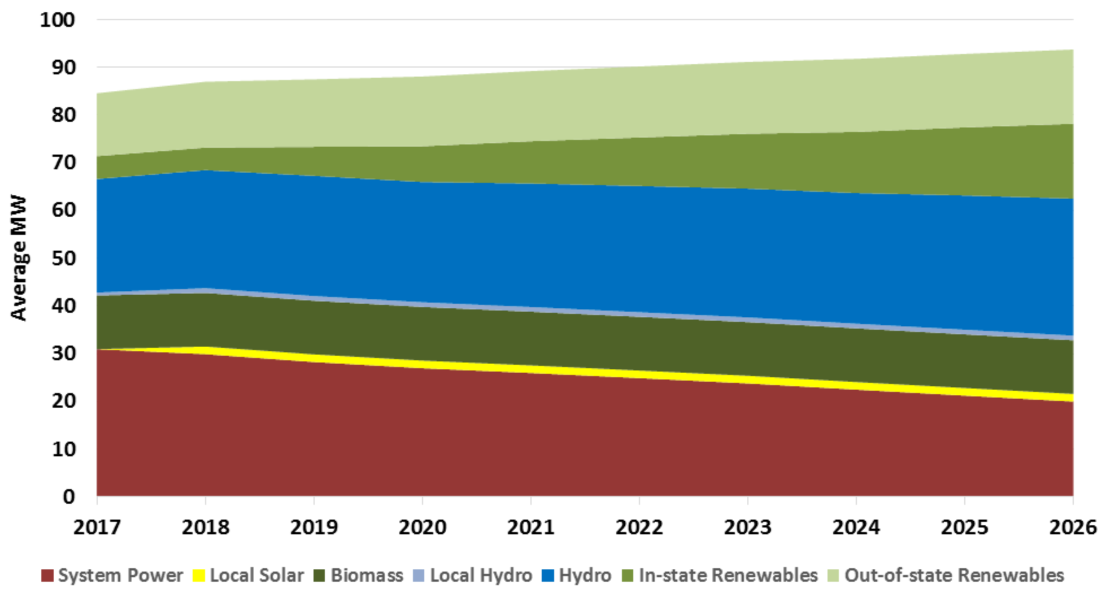

Figure 12: Supply mix for Scenario 3 - Higher Ratepayer Savings

Table 2 shows estimates of the economic benefit of the CCA to the local community under the different scenarios. The benefit is quantified as the amount of local expenditure and reserves that accrue to the CCA. The components of the benefit include:

- Ratepayer savings
- Spending on existing local generation
- Investment in the "soft costs" (i.e. not solar panels) for new solar panel installation for utility solar projects
- Spending on local programs such as energy efficiency, electric vehicle charging, etc.
- Spending on feed-in-tariff supply
- Personnel and administrative costs
- Financial reserves

All three scenarios show substantial expenditure, although Scenarios 1 and 2 show somewhat more expenditure due to the investment in local resources as compared to Scenario 3.

Table 2: Cumulative Local Expenditures in Year 5 in $mm

Case	Scenario 1	Scenario 2	Scenario 3
Bad	**$105**	**$105**	**$96**
Base	**$116**	**$115**	**$104**
Good	**$129**	**$127**	**$112**

Figure 13 shows the reserves accumulations for each scenario under each case. The criteria for feasibility were that reserves be at least $8mm under the bad case for each scenario. This led to a reserve accumulation of at least $16mm under the base case, and $25mm for the good case.

It is important for the CCA to accumulate reserves through the first years of operation. Doing so will provide the ability to absorb adverse financial conditions without having to raise rates. Keeping rates competitive with PG&E will be important towards long-term viability of the CCA because the CCA is not a monopoly and customers will be permitted to switch back to PG&E service at a future date if desired.

Reserves can also be helpful to reduce procurement costs by becoming a creditworthy counterparty in transactions. They can also be used eventually to provide funds for developing new generation and implementing new, innovative local programs. Once a threshold reserve level has been achieved, the CCA should be able to reduce the set-aside for reserves and use those funds for other purposes such as rate reduction.

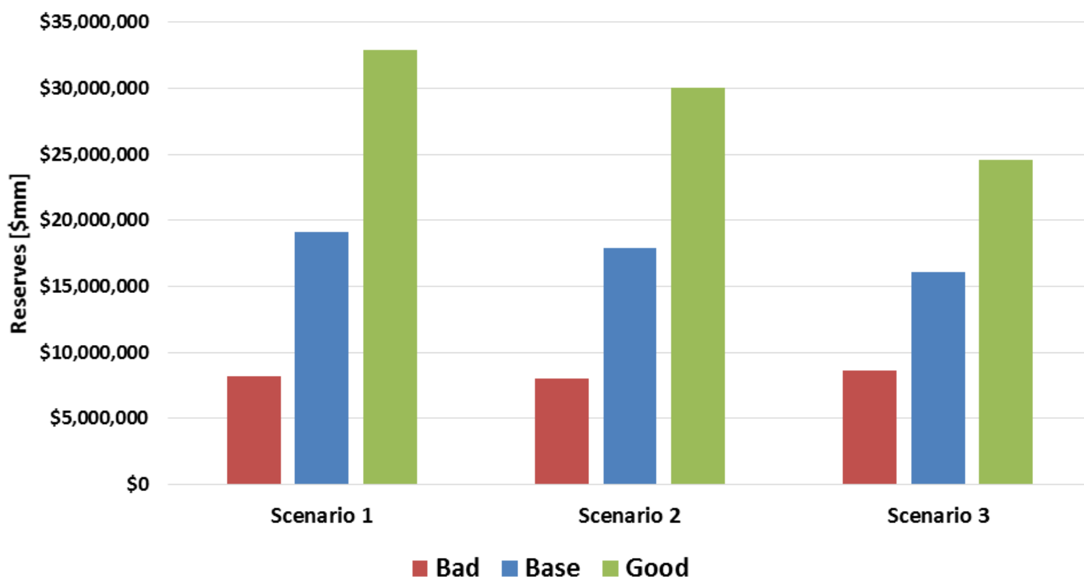

Figure 13: Financial reserves accumulation through year 5 for each scenario under base, bad and good cases.

Section 7 shows the Pro Formas for each Scenario and each case. It includes details for administrative overhead and other line items which have not been discussed explicitly within the study. These items are the same for all scenarios. They may vary somewhat from case to case depending on whether they are priced on a $/MWh basis due to the different load assumptions under the different cases. Figures Figure 14-Figure 16 show the cost breakdown in the base case for each of the three scenarios in 2021.

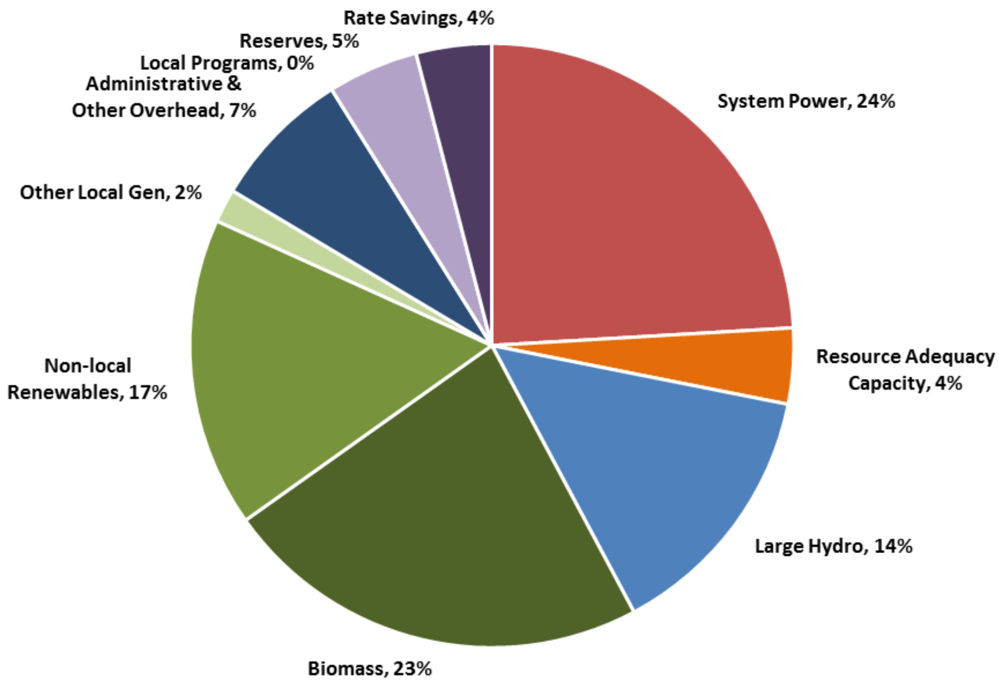

Figure 14: CCA cost breakdown in 2021 for Scenario 1, Base Case

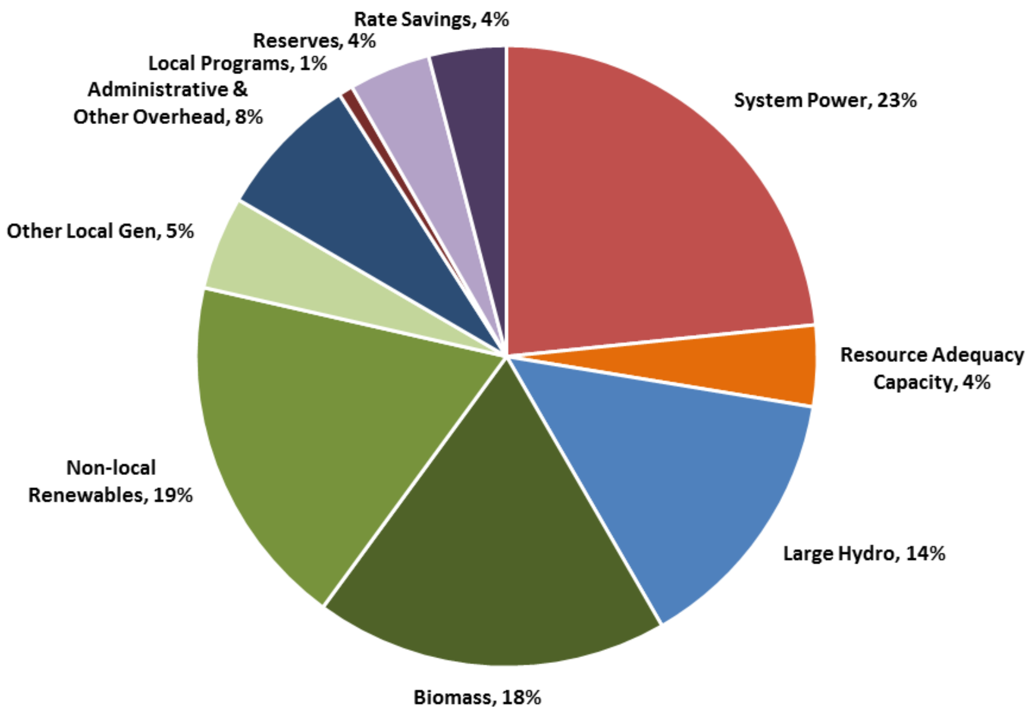

Figure 15: CCA cost breakdown in 2021 for Scenario 2, Base Case

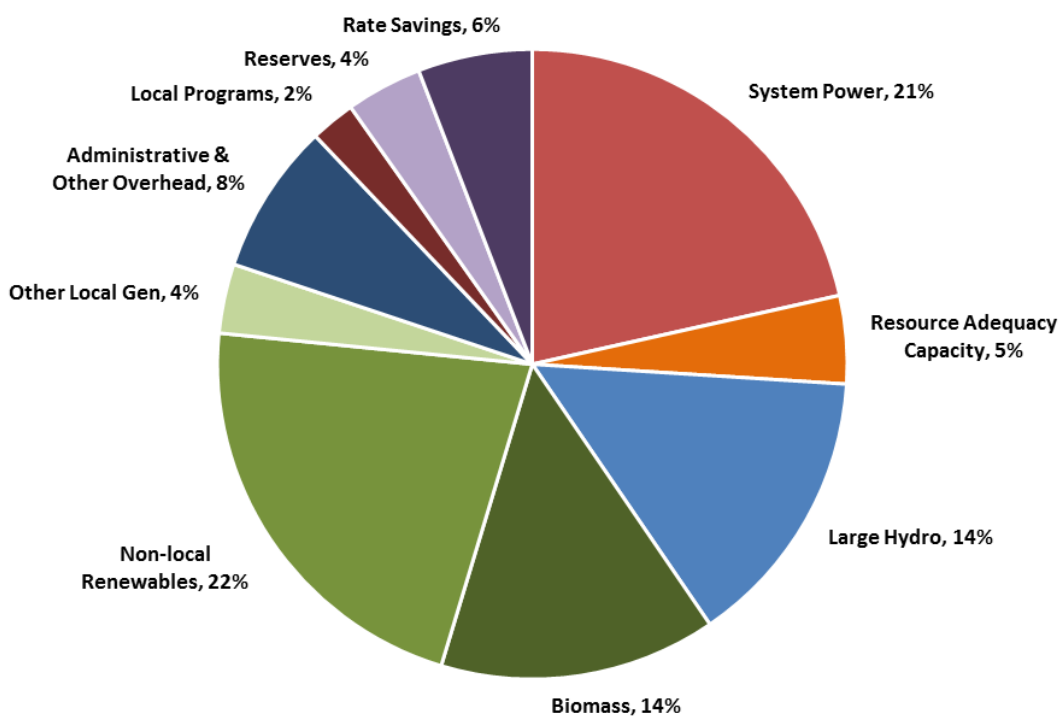

Figure 16: CCA cost breakdown in 2021 for Scenario 3, Base Case

5 Risks/Mitigations

Risk is omnipresent in the establishment and ongoing operation of any enterprise and a CCA is no exception. Most business risks for CCAs fall within three general categories:

1) Financial;
2) Regulatory and Political; and
3) Operational.

Unforeseen, unplanned for, and or unpreventable events in these areas could have significant impacts on CCA viability, and at the extreme could result in cessation of CCA activities, with CCA customers then compelled to return to the host investor owned utility (PG&E). Thus awareness of potential CCA business vulnerabilities and taking prudent and reasonable actions to mitigate possible injurious consequences must become integral to management policy as implemented through the day-to-day mission and conduct of all CCA employees. Given adoption of appropriate risk management policies, practices and procedures, a CCA will likely continue to well serve the interests of its customers and communities.

Characteristic CCA risks associated with procuring wholesale power supplies to meet retail electricity loads are discussed below. Risk areas more intrinsic to business operations may be more readily identified and mitigated; risk areas and events largely external to CCA business operations are more difficult to anticipate and control, but may be attenuated with nimble management and staff actions on a case-by-case basis. Any assessment of risk should also at least acknowledge our collective significant uncertainty about future events.

Known power industry risk exposure areas and possible mitigating strategies are detailed below, and outlined in Table 3, Table 4, and Table 5.

5.1 Financial Risk

There are at least three periods of financial need and activities related to establishing a CCA:

1) Implementation – City/county vote to establish CCA but prior to serving customers;
2) Launch – Commencement of customer service but prior to receiving revenues; and
3) Ongoing – Customers being served, and regular and routine service/revenue cycle established.

5.1.1 Risks related to Start-Up Funding and Working Capital

If, after investigation and feasibility studies, the cities and county approve the creation of the CCA, there will be a period of time between this initiating action and the actual setting up of the CCA business “storefront,” hiring staff, procuring power supply, interfacing with the incumbent utility (PG&E), noticing power customers, and the final objective: physically serving CCA customer electric loads. During this period RCEA will need funds to cover business start-up costs, primarily CCA staff salaries and infrastructure prior to receiving revenues. If the CCA fails for any reason during this period, RCEA will be left having to repay these funds through other revenues. Once the CCA launches successfully, the CCA will repay borrowed funds over time through CCA revenues.

5.1.2 Risks due to Over-procurement

CCAs have customer opt-out risk and must formally notice customers of this option two times prior to commencement of service and two times during the 60 day interlude immediately following commencement of service. Some customers will exercise this option, and the consequence to the CCA is a reduced revenue stream and a resulting reduction in the amount of wholesale power procurement needed (or the need to liquidate some supply commodity if a commitment to purchase has already been made).

Based on existing CCA experiences, a 10% opt-out rate assumption is used in this analysis. The risk of over procurement can be mitigated by reducing electricity procurement amounts accordingly, at least during initial commencement of CCA service until its customer base has stabilized. This approach should be addressed as part of initial CCA procurement strategy, which will take into account the variability of loads and the nearer and longer-term impacts of firm procurement commitments versus reliance on the short term power and CAISO balancing markets.

5.1.3 PG&E-related Risks

Opt-out rates will also be affected by the alternatively available PG&E retail rates for particular customer classes. All else being equal, as PG&E rates increase or decrease relative to CCA rates, there will be an inverse impact on the CCA's opt-out rate. Historically, PG&E rates have increased overall in the 4-6% range annually for the total of cost of service components (see Section 9). In the last 5 years, the increase has been in the 2-4% per year range, depending on the rate class.

Under a CCA approach, PG&E continues to provide billing, most customer service, and complete power delivery (poles and wires) service; the generation / power supply portion which otherwise would have been provided by PG&E is replaced with the CCA's power supply cost and other CCA related staff and operating costs. Thus an increase or decrease in non-generation related PG&E costs should not have any significant impact on CCA opt-out rates as price increases or decreases in this area are directly passed through to CCA customers. The most important PG&E cost component from a CCA perspective is the generation charge (along with the PCIA charge which will be discussed in the Regulatory and Political section below).

5.1.4 Customer loyalty as Risk Mitigation

PG&E's generation charge could decrease over time even as other non-generation PG&E costs increase, creating additional pressure on the CCA's ability to price-compete with PG&E. Actions to mitigate a situation in which PG&E's pricing is falling relative to the CCA, or becomes somewhat lower than the CCA's rates, are promoting local brand and local control, along with the ability to develop a more environmentally responsible power resource portfolio and the corresponding reduction in GHG emissions.

Other locally beneficial actions could include more environmentally friendly power supply, energy efficiency and renewable resource development programs tailored to local customer needs and wants. These types of actions will help to mitigate opt-out risk and the potential for customers who do not initially opt-out to return to PG&E over time.

Establishing sound and supportive customer relationships will advance CCA viability and help to stabilize revenues and customer loyalty. The longer-term predictability and durability of the CCA's customer base will help assure access to credit markets to meet working capital, efficiency programs, new resource investments, debt repayment, and other CCA financial needs. Financial risks always involve dollars, and almost every activity a CCA undertakes involves either the receipt or expenditure of dollars. Thus all CCA risks have potential financial ramifications, and there will be inevitable overlap with CCA operations and regulatory requirements. The most effective "risk absorbers" over time are management preparedness and the availability of sufficient reserve funds, which may be used to mitigate business uncertainty events.

Table 3: Financial and Related Risks

Risk Description	***Likely Risk Level***	***Mitigations***
Supply Imbalance, over or under-procurement	Low	Can be mitigated with prudent hedging and forward procurement activities
Customer Opt-Out	Low	Opt-out risk is most substantial during program commencement and can be mitigated with careful procurement planning allowing for initial supply flexibility
Current Power Market	Low	Current market prices are below historic averages. Risk of future price increases can be mitigated through hedging.
Future Power Market	Moderate	Many factors influence such as overall economy, continuation of fracking, natural gas prices, etc.
RCEA Exposure	Low	May lose seed monies if CCA not established.
Financial	Low	Prudent planning and operation, current market prices, coupled with existing CCA track records help to ameliorate financial risks

5.2 Regulatory and Political Risk

5.2.1 Legislative Risk

CCAs were created by California's Assembly Bill 117 legislation which was passed in 2002. Ultimately, and however unlikely, any organization legislatively "created" can be legislatively weakened or "eliminated." To the extent the incumbent electric utility perceives CCAs to be a threat or an encumbrance on its business model, they can use their influence to impair or possibly abolish CCA development. PG&E has and will use its weight at legislative and CPUC levels to assure its business viability is not challenged by the growth and success of existing and new CCAs[11].

5.2.2 Regulatory Risk

As alluded to above, PG&E will also attempt to shift cost of service charges to areas of its bill not avoidable by CCA customers, further reducing the ability of CCAs to be cost competitive with PG&E. This is especially observable in PG&E's Power Charge Indifference Adjustment (PCIA, sometimes called exit fee). This charge, which is applicable to all CCA customers, is intended to protect non-CCA PG&E customers from any economic consequences associated with "departing" CCA customers. But if PCIA charges are increased significantly, the economic incentives to establish a local CCA program can be eroded. The likely most effective manner to abate these types of incumbent utility fee increases and cost shifts is to actively monitor and participate in relevant legislative and CPUC proceedings to advance and protect CCA interests and benefits. This type of effort is most effective when CCAs join with other similarly situated CCAs to improve effectiveness and share costs.

5.2.3 Public Perceptions

Local citizen perception and support for CCA activities will also contribute to CCA durability. For example, there are few viable opportunities other than establishing a CCA for a community to strive for electricity related GHG neutrality. If local populations support this objective, this may engender CCA support and establishment at the legislative level, and also help mitigate additional barriers (such as significantly increasing the bonding requirements) at the legislature or CPUC. The activities and performance results of other CCAs may also impact CCA rules and regulations. Successful and locally acclaimed CCAs tend to cast all CCAs in a positive light and thus improve general legislative and public support. On the other hand, if a CCA were to fail, become financially distressed, operationally or in some other manner, consequences detrimental to all CCAs could occur. Thus each CCA must be tuned to, and meet the needs and pursue the objectives of its local constituency as well as monitor and acknowledge the happenings of other CCAs.

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[11] IOUs are not legally allowed to use ratepayer funds to oppose the formation of CCAs. However, they may lobby for favorable legislation and regulatory rulings that benefit themselves.

Other political and regulatory risks revolve around RPS and GHG requirements, and the availability of sufficient power resources to simultaneously meet these regulatory requirements and serve customer electrical loads. The potential cost impacts of power supplies under various sensitivities are addressed separately in this report (see Section 2.7).

Table 4: Regulatory and Related Risks and Mitigations

Risk Description	*Likely Risk Level*	*Mitigations*
Regulatory & Legislative	Moderate	An area to be carefully monitored and likely participate with other CCAs to influence and preserve a viable CCA alternative
Renewables availability	Low	Declining pricing and increased availability

5.3 Operational Risks

Operational risks fall into multiple categories including:

1) Performance of counterparties to CCA contracts,
2) Balancing power load with power supply,
3) CCA staffing,
4) Market price volatility (see Figure 17 as an example of recent gas market price volatility) and
5) CAISO related requirements, settlements and interactions.

As previously mentioned, virtually all operational issues may result in financial consequences for the CCA. CCA operational success depends on many of the previously discussed activities including:

- Implementing a robust governance and management structure;
- Power supplier/marketer relationships;
- Power project availability;
- Load forecasting;
- Power planning;
- Internal staff capability and retention;
- Attaining quality consulting services;
- Contracting with a dependable scheduling coordinator and validating CAISO settlements;
- Accurate and timely invoicing and revenue receipts;
- Accurate and timely payments to vendors.

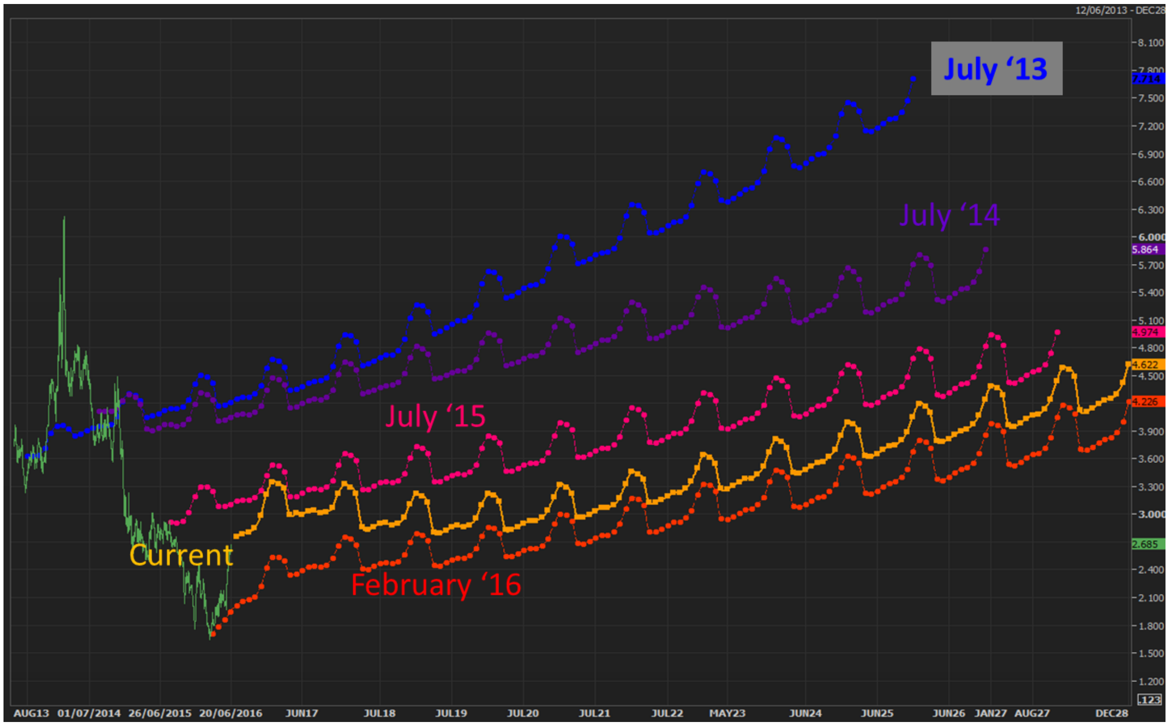

Figure 17: Historical cash and forward market prices for natural gas showing the volatility of energy prices

5.3.1 Load Uncertainty and Procurement

TEA has performed sensitivity assessments to evaluate power market price volatility risk as well as overall portfolio cost, in part, as a function of renewable resources availability and pricing. Once in operation, TEA would recommend the CCA use a stochastic model to evaluate the impacts of load as well as price and supply uncertainty on costs and revenues.

All wholesale power procurement strategies should take into account the cost consequences of over- and under-procurement relative to loads being served. Near- and longer-term customer loads are not known with certainty and are generally modeled based on historic load usage, expected load growth, weather, energy efficiency programs, and the like. Unusual weather such as excessive heat or cold can result in substantial deviations during any given time in the planned supply to meet actual power demand. This "real-time" deviation will be settled in the CAISO imbalance market at prices which are not known in advance. All utilities procuring supply to meet demand face these imbalance uncertainties.

Because power can generally not be stored, real-time imbalance pricing is generally based on the incremental/decremental production cost of the then on line "swing resources" (typically the added or subtracted fuel plus variable O&M cost of resources available and on-line capable of increasing or decreasing electrical output to match actual supply with actual demand – and in California, typically natural gas fired generation). Thus a utility scheduling delivery of more power to the grid than its load is consuming, will automatically liquidate its excess supply at CAISO imbalance prices which are uncertain and can change quickly. Forward purchases provide greater certainty over overall supply costs, improve the ability to plan and meet a budget, and reduce uncertainty associated with what can be a volatile real-time market. (There are other factors such as power system congestion and loss conditions which can affect real-time prices as well).

5.3.2 Risk Management

Although uncertainty and risk have always been integral to utility planning and performance, the last two decades have witnessed utility deregulation, extreme market price volatility, bankruptcies, complete business failures, revamped CAISO policies and procedures, non-performance of contract counter-parties, nearly endless lawsuits and legal proceedings, and the like. All outcomes of which have engendered implementation of more formal and extensive risk management practices in most utility organizations.

Such risk management practices are commonly labeled the "3Ps" which is short for risk management policies, practices, and procedures, approved and implemented by the governing body. These "3Ps" are intended to specify the ranges of staff position authorities and actions associated with the full scope of utility decision making. Further, some form of risk oversight committee (ROC – which may meet monthly or more frequently if necessary) is generally established to formally track and report staff/utility performance with the approved 3Ps.

Any events which deviate from the prescribed 3Ps are reported to the ROC for corrective action and/or to make recommendations to the governing body to revise the 3Ps as warranted. In the current power world, for example, most power suppliers will want to be assured that the person signing a contract and the person making day-to-day procurement decisions are duly authorized to make such decisions and expenditures; and such counter-parties may ask to review a company's 3Ps before commencing any business activities.

In short, the development, implementation, monitoring and maintenance of a formal enterprise risk management program can significantly contribute to the ongoing success of an organization and reduce the likelihood of debilitating consequences from unlikely or unforeseen events. Such a program, along with monitoring and feedback actions, provides performance expectations and parameters to all staff and management levels under the aegis of the governing body, and provides a formal mechanism to prepare for, track and respond to business challenges and risks.

Table 5: Operational Risks and Mitigations

Risk Description	*Likely Risk Level*	*Comments*
Attracting Staff	Low	Market salaries should attract available and needed staff and consultants
CCA "Failure"	Low	Established working model, careful planning and oversight will mitigate risk of failure

5.4 Locational and Time-of-Day Mismatch Risks

Within the California ISO, load is required to pay one price for energy provided directly from the ISO and supply is paid another, different price for energy supplied directly to the ISO. These prices may diverge substantially. Therefore, it may come to pass that load is paying a price higher than what it costs a generator to produce, but, at the same time the generator is selling energy for much lower prices on the generation it provides.

The principal risk mitigation tool available to manage the risk of price differences due to location differences are Congestion Revenue Rights ("CRRs"). Any Load-Serving Entity in California is entitled to a certain amount of CRRs which can be used to offset price differences between supply price and load prices. CRRs pay their owner the difference between energy prices at two distinct locations on the CAISO grid. Since a CCA will not own generation at the same point as its load (for billing purposes, CCA load is assumed to be at the default PG&E load aggregation point), there is a risk that the price it receives for its supply may vary substantially from the price it pays for its load. A CRR can serve to offset that difference.

There is a similar and related risk that arises if the supply generates at different hours of the day and/or different months of the year than the demand arises. This is the case with renewable supply. Again, the supply will be paid different prices than the load has to pay for energy which leads to the risk that the cost paid for supply to meet load is higher than anticipated based on the price of contracted renewable generation. The notion that a CCA can "lock-in" its costs and rates based upon buying or building a long-term supply portfolio is not the case. This reinforces the need to follow sound active risk management policies and strategies as discussed above.

6 Next steps

As of the preparation of this final technical study, the RCEA board has committed to proceeding with the next phase of the CCA implementation process. The key elements of the second phase are below.

- Develop the implementation plan, including determining the supply strategy, staffing requirements, organizational structure, electricity rate approach, and planning for the role-out of service
- Develop an RFP for procuring local biomass generation
- Begin branding the CCA and continue communicating with the public through advertising and local media
- Begin efforts for data management / customer service aspects of program

The latest timeline for the CCA implementation is shown in Section 10.

7 Appendix – Pro Formas and Supply Mixes

Table 6: Pro Forma for bad case for Scenario 1

Scenario 1; Bad Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	177119.6	275313.7	276807.7	279725.3	282422.8	285272.4	288152.1	291184.9	293996.1	296960.5
Low Income Residential	59062.3	92229.9	93152.2	94126.1	95024.5	95974.8	96934.5	97948.0	98882.9	99871.7
Agriculture	19609.7	28088.8	28369.7	28659.1	28939.9	29229.3	29521.6	29822.8	30115.0	30416.1
Small Commercial	61784.0	94156.8	95098.4	96078.1	97009.9	97980.0	98959.8	99979.2	100948.9	101958.4
Medium Commercial	33941.7	51662.7	52179.4	52730.3	53228.2	53760.5	54298.1	54871.4	55389.4	55943.3
Large Commercial & Industrial	93770.1	141834.9	143253.2	144752.8	146132.6	147593.9	149069.9	150630.4	152066.2	153586.8
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	447895.5488	687256.8143	692870.2924	700123.7019	706848.2642	713942.1188	721108.5034	728653.1415	735654.9662	743035.9008
Distribution Losses	21051.1	32301.1	32564.9	32905.8	33221.9	33555.3	33892.1	34246.7	34575.8	34922.7
Total Wholesale Load	468946.6	719557.9	725435.2	733029.5	740070.1	747497.4	755000.6	762899.8	770230.7	777958.6
Power Supply Costs										
Market Purchases	$ 13,701,219	$ 16,271,882	$ 16,310,206	$ 17,194,839	$ 17,366,426	$ 17,735,211	$ 18,394,832	$ 18,570,825	$ 18,893,618	$ 20,971,908
Net Renewable Energy	$ 6,791,612	$ 12,638,138	$ 13,086,147	$ 13,425,080	$ 13,923,417	$ 14,460,732	$ 14,963,220	$ 15,615,282	$ 16,144,954	$ 16,514,304
Retail Programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Resource Adequacy	$ 1,498,354	$ 2,310,310	$ 2,380,197	$ 2,450,216	$ 2,537,840	$ 2,620,426	$ 2,705,632	$ 2,784,985	$ 2,884,205	$ 2,977,732
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 562,126	$ 868,982	$ 882,775	$ 898,986	$ 914,867	$ 931,587	$ 948,782	$ 966,871	$ 984,651	$ 1,003,361
Staff and Other Operational	$ 2,357,765	$ 3,557,496	$ 3,584,398	$ 3,611,916	$ 3,640,068	$ 3,668,870	$ 3,698,340	$ 3,728,496	$ 3,759,356	$ 3,790,940
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 468,947	$ 719,558	$ 725,435	$ 733,030	$ 740,070	$ -	$ -	$ -	$ -	$ -
Total	$ 25,556,531	$ 36,631,127	$ 37,233,921	$ 38,578,827	$ 39,387,450	$ 39,426,826	$ 40,720,805	$ 41,676,459	$ 42,676,784	$ 45,268,244
PG&E Non Bypassable Charges										
PCIA	$ 10,309,748	$ 19,137,512	$ 19,349,634	$ 19,924,630	$ 20,747,905	$ 21,458,218	$ 22,078,558	$ 22,940,968	$ 23,483,445	$ 23,647,069
T&D	$ 38,421,649	$ 61,882,417	$ 65,000,160	$ 67,584,244	$ 69,599,122	$ 71,704,281	$ 73,873,290	$ 76,139,367	$ 78,409,740	$ 80,781,111
Regulatory/Other	$ 7,814,726	$ 11,551,628	$ 11,650,363	$ 11,546,577	$ 10,865,981	$ 10,972,192	$ 12,124,991	$ 12,249,586	$ 12,900,367	$ 13,027,134
Franchise Fee	$ 307,413	$ 470,496	$ 474,212	$ 479,178	$ 483,784	$ 488,642	$ 493,550	$ 498,714	$ 503,511	$ 508,565
PG&E Billing Services	$ 239,583	$ 366,233	$ 373,210	$ 380,322	$ 387,571	$ 394,959	$ 402,489	$ 410,164	$ 417,986	$ 425,959
Total	$ 57,093,119	$ 93,408,285	$ 96,847,580	$ 99,914,951	$ 102,084,363	$ 105,018,292	$ 108,972,877	$ 112,238,799	$ 115,715,049	$ 118,389,839
Reserves										
Annual Contribution	$ 388,962	$ 2,241,739	$ 2,107,903	$ 1,435,208	$ 1,997,268	$ 3,299,351	$ 3,448,538	$ 3,820,913	$ 4,548,112	$ 3,723,622
Cumulative Reserve Fund	$ 388,962	$ 2,630,701	$ 4,738,603	$ 6,173,812	$ 8,171,080	$ 11,470,431	$ 14,918,968	$ 18,739,882	$ 23,287,994	$ 27,011,615
Average Energy Costs										
Generation	$ 58.28	$ 54.52	$ 54.96	$ 56.33	$ 56.96	$ 56.46	$ 57.71	$ 58.44	$ 59.26	$ 62.18
PG&E Non Bypassable Charges	$ 126.25	$ 134.70	$ 138.55	$ 141.48	$ 143.19	$ 145.86	$ 149.88	$ 152.79	$ 156.04	$ 158.07
Reserves Contribution	$ 0.87	$ 3.26	$ 3.04	$ 2.05	$ 2.83	$ 4.62	$ 4.78	$ 5.24	$ 6.18	$ 5.01
Average Retail Rate	$ 185.40	$ 192.48	$ 196.56	$ 199.86	$ 202.97	$ 206.94	$ 212.37	$ 216.48	$ 221.49	$ 225.27
CCA Rate Benefit vs. PG&E	-4.2%	-1.3%	-1.3%	-1.1%	-1.0%	-0.9%	-1.0%	-0.9%	-1.1%	-1.5%
Renewable Attributes										
CO_2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 7: Pro Forma for base case for Scenario 1

Scenario 1; Base Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	187538.4	291583.3	293240.1	296329.5	299185.5	302202.7	305251.7	308463.3	311439.4	314578.2
Low Income Residential	62536.6	97655.1	98631.7	99663.0	100614.2	101620.3	102636.5	103709.7	104699.5	105746.5
Agriculture	20763.2	29741.1	30038.5	30344.9	30642.2	30948.7	31258.2	31577.1	31886.4	32205.3
Small Commercial	65418.3	99695.5	100692.4	101729.7	102716.4	103743.5	104781.0	105860.3	106887.1	107955.9
Medium Commercial	35938.2	54701.7	55248.7	55832.1	56359.2	56922.8	57492.1	58099.1	58647.7	59234.1
Large Commercial & Industrial	99286.0	150178.1	151679.9	153267.7	154728.6	156275.9	157838.7	159491.0	161011.2	162621.4
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	474088.9246	727524.9027	733541.0617	741218.8522	748336.516	755845.253	763430.669	771416.9196	778827.8073	786640.4703
Distribution Losses	22282.2	34193.7	34476.4	34837.3	35171.8	35524.7	35881.2	36256.6	36604.9	36972.1
Total Wholesale Load	496371.1	761718.6	768017.5	776056.1	783508.3	791370.0	799311.9	807673.5	815432.7	823612.6
Power Supply Costs										
Market Purchases	$ 17,265,149	$ 27,052,913	$ 27,530,416	$ 28,928,293	$ 29,996,169	$ 31,098,527	$ 32,324,720	$ 33,330,929	$ 34,277,234	$ 36,750,745
Net Renewable Energy	$ 6,238,233	$ 10,514,605	$ 10,877,843	$ 11,208,716	$ 11,571,355	$ 12,003,905	$ 12,448,995	$ 12,968,569	$ 13,402,507	$ 13,856,531
Retail Programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Resource Adequacy	$ 1,606,558	$ 2,477,225	$ 2,552,153	$ 2,626,921	$ 2,720,338	$ 2,808,436	$ 2,899,320	$ 2,984,023	$ 3,089,768	$ 3,189,503
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 595,000	$ 919,898	$ 934,593	$ 951,753	$ 968,565	$ 986,265	$ 1,004,466	$ 1,023,616	$ 1,042,436	$ 1,062,243
Staff and Other Operational	$ 2,394,892	$ 3,613,745	$ 3,641,208	$ 3,669,295	$ 3,698,020	$ 3,727,402	$ 3,757,457	$ 3,788,204	$ 3,819,662	$ 3,851,848
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 496,371	$ 761,719	$ 768,017	$ 776,056	$ 783,508	$ -	$ -	$ -	$ -	$ -
Total	$ 28,772,712	$ 45,604,865	$ 46,568,993	$ 48,425,796	$ 50,002,717	$ 50,634,534	$ 52,444,957	$ 54,105,341	$ 55,641,608	$ 58,720,869
PG&E Non Bypassable Charges										
PCIA	$ 9,280,819	$ 14,243,770	$ 13,975,271	$ 14,086,253	$ 14,190,502	$ 14,291,219	$ 14,418,797	$ 14,518,187	$ 14,394,725	$ 14,296,434
T&D	$ 40,664,825	$ 65,504,210	$ 68,813,307	$ 71,548,828	$ 73,681,697	$ 75,910,150	$ 78,206,177	$ 80,605,007	$ 83,008,284	$ 85,518,532
Regulatory/Other	$ 8,271,577	$ 12,228,434	$ 12,334,296	$ 12,224,489	$ 11,503,781	$ 11,616,204	$ 12,836,532	$ 12,968,418	$ 13,657,302	$ 13,791,480
Franchise Fee	$ 325,376	$ 498,048	$ 502,039	$ 507,295	$ 512,171	$ 517,312	$ 522,507	$ 527,973	$ 533,050	$ 538,400
PG&E Billing Services	$ 253,315	$ 387,227	$ 394,609	$ 402,133	$ 409,802	$ 417,618	$ 425,584	$ 433,704	$ 441,980	$ 450,415
Total	$ 58,795,912	$ 92,861,689	$ 96,019,523	$ 98,768,998	$ 100,297,953	$ 102,752,504	$ 106,409,597	$ 109,053,290	$ 112,035,341	$ 114,595,260
Reserves										
Annual Contribution	$ 3,945,591	$ 4,586,489	$ 4,186,385	$ 3,118,435	$ 3,255,067	$ 4,285,179	$ 4,197,359	$ 4,185,771	$ 4,742,558	$ 3,695,223
Cumulative Reserve Fund	$ 3,945,591	$ 8,532,079	$ 12,718,464	$ 15,836,899	$ 19,091,966	$ 23,377,145	$ 27,574,504	$ 31,760,275	$ 36,502,833	$ 40,198,056
Average Energy Costs										
Generation	$ 61.91	$ 63.90	$ 64.71	$ 66.56	$ 68.05	$ 68.23	$ 69.94	$ 71.38	$ 72.69	$ 75.90
PG&E Non Bypassable Charges	$ 122.80	$ 126.42	$ 129.68	$ 132.03	$ 132.80	$ 134.71	$ 138.14	$ 140.12	$ 142.60	$ 144.42
Reserves Contribution	$ 8.32	$ 6.30	$ 5.71	$ 4.21	$ 4.35	$ 5.67	$ 5.50	$ 5.43	$ 6.09	$ 4.70
Average Retail Rate	$ 193.03	$ 196.63	$ 200.09	$ 202.79	$ 205.20	$ 208.60	$ 213.58	$ 216.93	$ 221.38	$ 225.02
CCA Rate Benefit vs. PG&E	-1.3%	-1.2%	-1.4%	-1.5%	-1.7%	-1.9%	-2.1%	-2.3%	-2.7%	-3.0%
Renewable Attributes										
CO2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 8: Pro Forma for good case for Scenario 1

Scenario 1; Good Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	197957.2	307853.0	309672.4	312933.7	315948.1	319133.0	322351.3	325741.7	328882.7	332195.9
Low Income Residential	66010.8	103080.4	104111.2	105199.8	106203.9	107265.9	108338.6	109471.3	110516.2	111621.3
Agriculture	21916.8	31393.3	31707.3	32030.8	32344.6	32668.0	32994.7	33331.3	33657.9	33994.5
Small Commercial	69052.7	105234.1	106286.5	107381.4	108422.8	109507.0	110602.1	111741.5	112825.2	113953.5
Medium Commercial	37934.8	57740.7	58318.1	58933.9	59490.3	60085.2	60686.1	61326.8	61905.9	62524.9
Large Commercial & Industrial	104801.9	158521.3	160106.5	161782.6	163324.7	164957.9	166607.5	168351.6	169956.3	171655.9
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	500282.3004	767792.991	774211.831	782314.0025	789824.7677	797748.3873	805752.8346	814180.6978	822000.6484	830245.0399
Distribution Losses	23513.3	36086.3	36388.0	36768.8	37121.8	37494.2	37870.4	38266.5	38634.0	39021.5
Total Wholesale Load	523795.6	803879.3	810599.8	819082.8	826946.5	835242.6	843623.2	852447.2	860634.7	869266.6
Power Supply Costs										
Market Purchases	$ 27,234,551	$ 43,697,461	$ 44,852,139	$ 47,181,627	$ 49,688,237	$ 52,040,241	$ 54,711,257	$ 56,379,796	$ 57,857,043	$ 61,541,868
Net Renewable Energy	$ 4,317,245	$ 7,370,260	$ 7,642,361	$ 7,887,860	$ 8,009,700	$ 8,268,005	$ 8,508,786	$ 8,967,392	$ 9,340,001	$ 9,786,477
Retail Programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Resource Adequacy	$ 1,714,762	$ 2,644,139	$ 2,724,109	$ 2,803,627	$ 2,902,837	$ 2,996,446	$ 3,093,008	$ 3,183,061	$ 3,295,332	$ 3,401,275
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 627,874	$ 970,814	$ 986,411	$ 1,004,521	$ 1,022,263	$ 1,040,942	$ 1,060,150	$ 1,080,360	$ 1,100,222	$ 1,121,124
Staff and Other Operational	$ 2,432,020	$ 3,669,993	$ 3,698,019	$ 3,726,674	$ 3,755,973	$ 3,785,934	$ 3,816,575	$ 3,847,913	$ 3,879,967	$ 3,912,757
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 523,796	$ 803,879	$ 810,600	$ 819,083	$ 826,947	$ -	$ -	$ -	$ -	$ -
Total	$ 37,026,755	$ 59,421,308	$ 60,978,401	$ 63,688,153	$ 66,470,718	$ 68,141,568	$ 71,199,776	$ 73,468,522	$ 75,482,565	$ 79,773,501
PG&E Non Bypassable Charges										
PCIA	$ 4,632,679	$ 5,769,683	$ 4,728,971	$ 3,980,614	$ 2,902,883	$ 1,943,743	$ 868,122	$ 185,943	$ (709,946)	$ (1,702,607)
T&D	$ 42,908,001	$ 69,126,003	$ 72,626,455	$ 75,513,411	$ 77,764,273	$ 80,116,020	$ 82,539,063	$ 85,070,648	$ 87,606,829	$ 90,255,953
Regulatory/Other	$ 8,728,429	$ 12,905,241	$ 13,018,229	$ 12,902,402	$ 12,141,581	$ 12,260,216	$ 13,548,073	$ 13,687,250	$ 14,414,237	$ 14,555,826
Franchise Fee	$ 343,339	$ 525,599	$ 529,866	$ 535,412	$ 540,557	$ 545,982	$ 551,463	$ 557,232	$ 562,589	$ 568,234
PG&E Billing Services	$ 267,047	$ 408,222	$ 416,008	$ 423,944	$ 432,033	$ 440,277	$ 448,680	$ 457,244	$ 465,973	$ 474,870
Total	$ 56,879,494	$ 88,734,747	$ 91,319,528	$ 93,355,783	$ 93,781,326	$ 95,306,238	$ 97,955,402	$ 99,958,317	$ 102,339,683	$ 104,152,276
Reserves										
Annual Contribution	$ 7,030,051	$ 8,140,371	$ 7,264,805	$ 5,515,214	$ 4,941,155	$ 5,403,293	$ 4,528,086	$ 4,228,397	$ 4,716,529	$ 2,834,200
Cumulative Reserve Fund	$ 7,030,051	$ 15,170,422	$ 22,435,228	$ 27,950,442	$ 32,891,597	$ 38,294,890	$ 42,822,976	$ 47,051,373	$ 51,767,901	$ 54,602,101
Average Energy Costs										
Generation	$ 75.23	$ 78.61	$ 79.98	$ 82.64	$ 85.39	$ 86.65	$ 89.61	$ 91.48	$ 93.08	$ 97.34
PG&E Non Bypassable Charges	$ 112.47	$ 114.35	$ 116.73	$ 118.11	$ 117.51	$ 118.23	$ 120.33	$ 121.53	$ 123.25	$ 124.19
Reserves Contribution	$ 14.05	$ 10.60	$ 9.38	$ 7.05	$ 6.26	$ 6.77	$ 5.62	$ 5.19	$ 5.74	$ 3.41
Average Retail Rate	$ 201.76	$ 203.57	$ 206.10	$ 207.79	$ 209.15	$ 211.66	$ 215.55	$ 218.20	$ 222.07	$ 224.95
CCA Rate Benefit vs. PG&E	0.2%	-0.6%	-1.3%	-1.8%	-2.5%	-3.1%	-3.7%	-4.1%	-4.5%	-5.0%
Renewable Attributes										
CO_2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 9: Pro Forma for bad case for Scenario 2

Scenario 2; Bad Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	177119.6	274678.3	275536.4	278452.5	281151.6	284001.2	286881.7	289911.2	292726.3	295690.1
Low Income Residential	59062.3	92229.9	93152.2	94126.1	95024.5	95974.8	96934.5	97948.0	98882.9	99871.7
Agriculture	19609.7	28088.8	28369.7	28659.1	28939.9	29229.3	29521.6	29822.8	30115.0	30416.1
Small Commercial	61784.0	94156.8	95098.4	96078.1	97009.9	97980.0	98959.8	99979.2	100948.9	101958.4
Medium Commercial	33941.7	51662.7	52179.4	52730.3	53228.2	53760.5	54298.1	54871.4	55389.4	55943.3
Large Commercial & Industrial	93770.1	141834.9	143253.2	144752.8	146132.6	147593.9	149069.9	150630.4	152066.2	153586.8
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	447895.5488	686621.4359	691599.0153	698850.8283	705577.0739	712670.9025	719838.0566	727379.3889	734385.0744	741765.5026
Distribution Losses	21051.1	32271.2	32505.2	32846.0	33162.1	33495.5	33832.4	34186.8	34516.1	34863.0
Total Wholesale Load	468946.6	718892.6	724104.2	731696.8	738739.2	746166.4	753670.4	761566.2	768901.2	776628.5
Power Supply Costs										
Market Purchases	$ 13,701,219	$ 16,256,971	$ 16,280,328	$ 17,163,694	$ 17,335,143	$ 17,703,375	$ 18,362,008	$ 18,537,941	$ 18,860,661	$ 20,935,173
Net Renewable Energy	$ 5,850,344	$ 12,167,328	$ 12,588,540	$ 12,987,489	$ 13,459,457	$ 13,948,860	$ 14,404,205	$ 15,002,326	$ 15,483,446	$ 15,893,471
Retail Programs	$ 333,333	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Resource Adequacy	$ 1,568,734	$ 2,415,331	$ 2,484,605	$ 2,556,711	$ 2,646,463	$ 2,731,222	$ 2,818,647	$ 2,900,258	$ 3,001,790	$ 3,097,664
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 562,126	$ 868,179	$ 881,156	$ 897,351	$ 913,222	$ 929,929	$ 947,110	$ 965,181	$ 982,951	$ 1,001,646
Staff and Other Operational	$ 2,357,765	$ 3,557,496	$ 3,584,398	$ 3,611,916	$ 3,640,068	$ 3,668,870	$ 3,698,340	$ 3,728,496	$ 3,759,356	$ 3,790,940
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 468,947	$ 718,893	$ 724,104	$ 731,697	$ 738,739	$ -	$ -	$ -	$ -	$ -
Total	$ 25,018,976	$ 36,748,960	$ 37,307,891	$ 38,713,620	$ 39,497,853	$ 39,492,255	$ 40,740,310	$ 41,644,201	$ 42,598,204	$ 45,228,893
PG&E Non Bypassable Charges										
PCIA	$ 10,309,748	$ 19,118,576	$ 19,311,708	$ 19,885,984	$ 20,708,176	$ 21,417,599	$ 22,037,250	$ 22,898,455	$ 23,440,546	$ 23,604,310
T&D	$ 38,421,649	$ 61,808,991	$ 64,847,094	$ 67,426,773	$ 69,438,714	$ 71,540,661	$ 73,706,499	$ 75,968,798	$ 78,236,286	$ 80,604,118
Regulatory/Other	$ 7,814,726	$ 11,540,820	$ 11,629,997	$ 11,527,929	$ 10,846,780	$ 10,952,997	$ 12,102,574	$ 12,227,117	$ 12,876,347	$ 13,003,111
Franchise Fee	$ 307,413	$ 469,997	$ 473,214	$ 478,178	$ 482,786	$ 487,644	$ 492,552	$ 497,714	$ 502,514	$ 507,568
PG&E Billing Services	$ 239,583	$ 366,233	$ 373,210	$ 380,322	$ 387,571	$ 394,959	$ 402,489	$ 410,164	$ 417,986	$ 425,959
Total	$ 57,093,119	$ 93,304,617	$ 96,635,224	$ 99,699,187	$ 101,864,026	$ 104,793,860	$ 108,741,364	$ 112,002,248	$ 115,473,679	$ 118,145,066
Reserves										
Annual Contribution	$ 926,081	$ 2,086,613	$ 1,959,672	$ 1,225,568	$ 1,810,293	$ 3,155,653	$ 3,348,975	$ 3,771,349	$ 4,542,828	$ 3,676,787
Cumulative Reserve Fund	$ 926,081	$ 3,012,694	$ 4,972,366	$ 6,197,934	$ 8,008,228	$ 11,163,880	$ 14,512,855	$ 18,284,204	$ 22,827,033	$ 26,503,820
Average Energy Costs										
Generation	$ 57.08	$ 54.74	$ 55.17	$ 56.62	$ 57.21	$ 56.65	$ 57.84	$ 58.50	$ 59.26	$ 62.23
PG&E Non Bypassable Charges	$ 126.25	$ 134.67	$ 138.50	$ 141.43	$ 143.14	$ 145.81	$ 149.82	$ 152.73	$ 155.99	$ 158.02
Reserves Contribution	$ 2.07	$ 3.04	$ 2.83	$ 1.75	$ 2.57	$ 4.43	$ 4.65	$ 5.18	$ 6.19	$ 4.96
Average Retail Rate	$ 185.40	$ 192.45	$ 196.51	$ 199.81	$ 202.92	$ 206.89	$ 212.31	$ 216.42	$ 221.43	$ 225.21
CCA Rate Benefit vs. PG&E	-4.2%	-1.3%	-1.3%	-1.1%	-1.0%	-1.0%	-1.0%	-0.9%	-1.1%	-1.5%
Renewable Attributes										
CO2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 10: Pro Forma for base case for Scenario 2

Scenario 2; Base Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	187538.4	290948.0	291968.8	295056.7	297914.3	300931.5	303981.2	307189.5	310169.5	313307.8
Low Income Residential	62536.6	97655.1	98631.7	99663.0	100614.2	101620.3	102636.5	103709.7	104699.5	105746.5
Agriculture	20763.2	29741.1	30038.5	30344.9	30642.2	30948.7	31258.2	31577.1	31886.4	32205.3
Small Commercial	65418.3	99695.5	100692.4	101729.7	102716.4	103743.5	104781.0	105860.3	106887.1	107955.9
Medium Commercial	35938.2	54701.7	55248.7	55832.1	56359.2	56922.8	57492.1	58099.1	58647.7	59234.1
Large Commercial & Industrial	99286.0	150178.1	151679.9	153267.7	154728.6	156275.9	157838.7	159491.0	161011.2	162621.4
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	474088.9246	726889.5243	732269.7846	739945.9786	747065.3257	754574.0367	762160.2222	770143.1671	777557.9155	785370.0721
Distribution Losses	22282.2	34163.8	34416.7	34777.5	35112.1	35465.0	35821.5	36196.7	36545.2	36912.4
Total Wholesale Load	496371.1	761053.3	766686.5	774723.4	782177.4	790039.0	797981.8	806339.9	814103.1	822282.5
Power Supply Costs										
Market Purchases	$ 17,265,149	$ 27,029,430	$ 27,482,811	$ 28,878,752	$ 29,945,058	$ 31,045,846	$ 32,270,249	$ 33,275,229	$ 34,220,586	$ 36,689,890
Net Renewable Energy	$ 5,442,475	$ 10,232,436	$ 10,656,578	$ 11,002,737	$ 11,332,857	$ 11,728,274	$ 12,133,771	$ 12,617,468	$ 13,012,219	$ 13,549,698
Retail Programs	$ 333,333	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Resource Adequacy	$ 1,676,938	$ 2,582,246	$ 2,656,560	$ 2,733,417	$ 2,828,962	$ 2,919,232	$ 3,012,335	$ 3,099,296	$ 3,207,354	$ 3,309,436
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 595,000	$ 919,094	$ 932,974	$ 950,119	$ 966,919	$ 984,606	$ 1,002,794	$ 1,021,926	$ 1,040,737	$ 1,060,527
Staff and Other Operational	$ 2,394,892	$ 3,613,745	$ 3,641,208	$ 3,669,295	$ 3,698,020	$ 3,727,402	$ 3,757,457	$ 3,788,204	$ 3,819,662	$ 3,851,848
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 496,371	$ 761,053	$ 766,686	$ 774,723	$ 782,177	$ -	$ -	$ -	$ -	$ -
Total	$ 28,380,667	$ 45,902,766	$ 46,901,579	$ 48,773,804	$ 50,318,755	$ 50,915,360	$ 52,686,606	$ 54,312,122	$ 55,810,558	$ 58,971,399
PG&E Non Bypassable Charges										
PCIA	$ 9,280,819	$ 14,230,094	$ 13,948,638	$ 14,059,654	$ 14,163,996	$ 14,264,790	$ 14,392,413	$ 14,491,827	$ 14,368,917	$ 14,271,046
T&D	$ 40,664,825	$ 65,430,783	$ 68,660,242	$ 71,391,357	$ 73,521,289	$ 75,746,531	$ 78,039,386	$ 80,434,438	$ 82,834,831	$ 85,341,539
Regulatory/Other	$ 8,271,577	$ 12,217,626	$ 12,313,930	$ 12,205,842	$ 11,484,580	$ 11,597,009	$ 12,814,115	$ 12,945,949	$ 13,633,282	$ 13,767,457
Franchise Fee	$ 325,376	$ 497,549	$ 501,041	$ 506,295	$ 511,172	$ 516,314	$ 521,509	$ 526,973	$ 532,053	$ 537,402
PG&E Billing Services	$ 253,315	$ 387,227	$ 394,609	$ 402,133	$ 409,802	$ 417,618	$ 425,584	$ 433,704	$ 441,980	$ 450,415
Total	$ 58,795,912	$ 92,763,279	$ 95,818,460	$ 98,565,280	$ 100,090,839	$ 102,542,261	$ 106,193,006	$ 108,832,891	$ 111,811,062	$ 114,367,858
Reserves										
Annual Contribution	$ 4,336,765	$ 4,242,647	$ 3,762,935	$ 2,678,975	$ 2,845,551	$ 3,908,906	$ 3,858,298	$ 3,879,515	$ 4,471,840	$ 3,340,474
Cumulative Reserve Fund	$ 4,336,765	$ 8,579,412	$ 12,342,347	$ 15,021,322	$ 17,866,873	$ 21,775,779	$ 25,634,077	$ 29,513,592	$ 33,985,432	$ 37,325,906
Average Energy Costs										
Generation	$ 61.08	$ 64.37	$ 65.27	$ 67.14	$ 68.59	$ 68.71	$ 70.37	$ 71.77	$ 73.03	$ 76.35
PG&E Non Bypassable Charges	$ 122.80	$ 126.40	$ 129.63	$ 131.98	$ 132.75	$ 134.66	$ 138.09	$ 140.07	$ 142.55	$ 144.37
Reserves Contribution	$ 9.15	$ 5.84	$ 5.14	$ 3.62	$ 3.81	$ 5.18	$ 5.06	$ 5.04	$ 5.75	$ 4.25
Average Retail Rate	$ 193.03	$ 196.60	$ 200.04	$ 202.74	$ 205.14	$ 208.55	$ 213.52	$ 216.87	$ 221.33	$ 224.96
CCA Rate Benefit vs. PG&E	-1.3%	-1.2%	-1.4%	-1.5%	-1.7%	-2.0%	-2.1%	-2.3%	-2.7%	-3.0%
Renewable Attributes										
CO2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 11: Pro Forma for good case for Scenario 2

Scenario 2; Good Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	197957.2	307217.6	308401.2	311660.8	314676.9	317861.8	321080.8	324467.9	327612.8	330925.5
Low Income Residential	66010.8	103080.4	104111.2	105199.8	106203.9	107265.9	108338.6	109471.3	110516.2	111621.3
Agriculture	21916.8	31393.3	31707.3	32030.8	32344.6	32668.0	32994.7	33331.3	33657.9	33994.5
Small Commercial	69052.7	105234.1	106286.5	107381.4	108422.8	109507.0	110602.1	111741.5	112825.2	113953.5
Medium Commercial	37934.8	57740.7	58318.1	58933.9	59490.3	60085.2	60686.1	61326.8	61905.9	62524.9
Large Commercial & Industrial	104801.9	158521.3	160106.5	161782.6	163324.7	164957.9	166607.5	168351.6	169956.3	171655.9
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	500282.3004	767157.6127	772940.5539	781041.1289	788553.5774	796477.171	804482.3878	812906.9453	820730.7567	828974.6417
Distribution Losses	23513.3	36056.4	36328.2	36708.9	37062.0	37434.4	37810.7	38206.6	38574.3	38961.8
Total Wholesale Load	523795.6	803214.0	809268.8	817750.1	825615.6	833911.6	842293.1	851113.6	859305.1	867936.4
Power Supply Costs										
Market Purchases	$ 27,234,551	$ 43,661,543	$ 44,778,742	$ 47,104,990	$ 49,607,842	$ 51,956,827	$ 54,623,968	$ 56,290,481	$ 57,766,408	$ 61,445,399
Net Renewable Energy	$ 3,882,743	$ 7,430,151	$ 7,754,346	$ 7,988,580	$ 8,100,931	$ 8,341,477	$ 8,564,486	$ 8,997,281	$ 9,342,231	$ 9,945,167
Retail Programs	$ 333,333	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Resource Adequacy	$ 1,785,142	$ 2,749,161	$ 2,828,516	$ 2,910,122	$ 3,011,460	$ 3,107,242	$ 3,206,023	$ 3,298,334	$ 3,412,917	$ 3,521,207
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 627,874	$ 970,010	$ 984,792	$ 1,002,887	$ 1,020,617	$ 1,039,283	$ 1,058,479	$ 1,078,670	$ 1,098,522	$ 1,119,409
Staff and Other Operational	$ 2,432,020	$ 3,669,993	$ 3,698,019	$ 3,726,674	$ 3,755,973	$ 3,785,934	$ 3,816,575	$ 3,847,913	$ 3,879,967	$ 3,912,757
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 523,796	$ 803,214	$ 809,269	$ 817,750	$ 825,616	$ -	$ -	$ -	$ -	$ -
Total	$ 36,995,966	$ 60,048,833	$ 61,618,445	$ 64,315,764	$ 67,087,201	$ 68,740,763	$ 71,779,530	$ 74,022,679	$ 76,010,045	$ 80,453,939
PG&E Non Bypassable Charges										
PCIA	$ 4,632,679	$ 5,763,679	$ 4,718,808	$ 3,971,745	$ 2,895,831	$ 1,938,277	$ 864,394	$ 183,297	$ (711,152)	$ (1,702,259)
T&D	$ 42,908,001	$ 69,052,576	$ 72,473,389	$ 75,355,940	$ 77,603,865	$ 79,952,400	$ 82,372,272	$ 84,900,078	$ 87,433,376	$ 90,078,960
Regulatory/Other	$ 8,728,429	$ 12,894,433	$ 12,997,863	$ 12,883,754	$ 12,122,380	$ 12,241,021	$ 13,525,656	$ 13,664,781	$ 14,390,217	$ 14,531,803
Franchise Fee	$ 343,339	$ 525,100	$ 528,868	$ 534,413	$ 539,559	$ 544,984	$ 550,466	$ 556,232	$ 561,592	$ 567,236
PG&E Billing Services	$ 267,047	$ 408,222	$ 416,008	$ 423,944	$ 432,033	$ 440,277	$ 448,680	$ 457,244	$ 465,973	$ 474,870
Total	$ 56,879,494	$ 88,644,010	$ 91,134,936	$ 93,169,795	$ 93,593,667	$ 95,116,959	$ 97,761,467	$ 99,761,632	$ 102,140,005	$ 103,950,610
Reserves										
Annual Contribution	$ 7,059,775	$ 7,454,437	$ 6,509,309	$ 4,771,573	$ 4,206,221	$ 4,683,305	$ 3,825,247	$ 3,548,922	$ 4,061,293	$ 2,023,378
Cumulative Reserve Fund	$ 7,059,775	$ 14,514,212	$ 21,023,521	$ 25,795,095	$ 30,001,316	$ 34,684,621	$ 38,509,869	$ 42,058,791	$ 46,120,083	$ 48,143,461
Average Energy Costs										
Generation	$ 75.17	$ 79.49	$ 80.94	$ 83.57	$ 86.31	$ 87.54	$ 90.47	$ 92.31	$ 93.86	$ 98.31
PG&E Non Bypassable Charges	$ 112.47	$ 114.33	$ 116.68	$ 118.06	$ 117.46	$ 118.19	$ 120.28	$ 121.48	$ 123.20	$ 124.14
Reserves Contribution	$ 14.11	$ 9.72	$ 8.42	$ 6.11	$ 5.33	$ 5.88	$ 4.75	$ 4.37	$ 4.95	$ 2.44
Average Retail Rate	$ 201.76	$ 203.54	$ 206.05	$ 207.74	$ 209.10	$ 211.61	$ 215.50	$ 218.15	$ 222.01	$ 224.89
CCA Rate Benefit vs. PG&E	0.2%	-0.6%	-1.3%	-1.8%	-2.5%	-3.1%	-3.7%	-4.1%	-4.5%	-5.0%
Renewable Attributes										
CO2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 12: Pro Forma for bad case for Scenario 3

Scenario 3; Bad Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	177119.6	274042.9	274265.2	277179.6	279880.4	282730.0	285611.2	288637.4	291456.4	294419.7
Low Income Residential	59062.3	92229.9	93152.2	94126.1	95024.5	95974.8	96934.5	97948.0	98882.9	99871.7
Agriculture	19609.7	28088.8	28369.7	28659.1	28939.9	29229.3	29521.6	29822.8	30115.0	30416.1
Small Commercial	61784.0	94156.8	95098.4	96078.1	97009.9	97980.0	98959.8	99979.2	100948.9	101958.4
Medium Commercial	33941.7	51662.7	52179.4	52730.3	53228.2	53760.5	54298.1	54871.4	55389.4	55943.3
Large Commercial & Industrial	93770.1	141834.9	143253.2	144752.8	146132.6	147593.9	149069.9	150630.4	152066.2	153586.8
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	447895.5488	685986.0576	690327.7382	697577.9547	704305.8836	711399.6862	718567.6099	726105.6364	733115.1826	740495.1044
Distribution Losses	21051.1	32241.3	32445.4	32786.2	33102.4	33435.8	33772.7	34127.0	34456.4	34803.3
Total Wholesale Load	468946.6	718227.4	722773.1	730364.1	737408.3	744835.5	752340.3	760232.6	767571.6	775298.4
Power Supply Costs										
Market Purchases	$ 13,701,219	$ 16,242,060	$ 16,250,449	$ 17,132,550	$ 17,303,859	$ 17,671,538	$ 18,329,184	$ 18,505,056	$ 18,827,703	$ 20,898,437
Net Renewable Energy	$ 4,887,524	$ 9,716,688	$ 10,140,071	$ 10,500,900	$ 10,904,146	$ 11,327,966	$ 11,727,887	$ 12,240,071	$ 12,658,402	$ 13,012,033
Retail Programs	$ 1,000,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
Resource Adequacy	$ 1,639,114	$ 2,520,353	$ 2,589,012	$ 2,663,207	$ 2,755,086	$ 2,842,017	$ 2,931,662	$ 3,015,530	$ 3,119,376	$ 3,217,597
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 562,126	$ 867,375	$ 879,536	$ 895,717	$ 911,576	$ 928,270	$ 945,439	$ 963,491	$ 981,251	$ 999,930
Staff and Other Operational	$ 2,357,765	$ 3,557,496	$ 3,584,398	$ 3,611,916	$ 3,640,068	$ 3,668,870	$ 3,698,340	$ 3,728,496	$ 3,759,356	$ 3,790,940
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 468,947	$ 718,227	$ 722,773	$ 730,364	$ 737,408	$ -	$ -	$ -	$ -	$ -
Total	$ 24,793,204	$ 35,386,961	$ 35,931,000	$ 37,299,415	$ 38,016,906	$ 37,948,661	$ 39,142,511	$ 39,962,644	$ 40,856,088	$ 43,428,937
PG&E Non Bypassable Charges										
PCIA	$ 10,309,748	$ 19,099,641	$ 19,273,782	$ 19,847,338	$ 20,668,447	$ 21,376,980	$ 21,995,942	$ 22,855,942	$ 23,397,646	$ 23,561,551
T&D	$ 38,421,649	$ 61,735,564	$ 64,694,029	$ 67,269,302	$ 69,278,305	$ 71,377,042	$ 73,539,708	$ 75,798,228	$ 78,062,833	$ 80,427,125
Regulatory/Other	$ 7,814,726	$ 11,530,012	$ 11,609,631	$ 11,509,282	$ 10,827,579	$ 10,933,802	$ 12,080,157	$ 12,204,648	$ 12,852,327	$ 12,979,088
Franchise Fee	$ 307,413	$ 469,498	$ 472,216	$ 477,178	$ 481,788	$ 486,646	$ 491,554	$ 496,713	$ 501,517	$ 506,570
PG&E Billing Services	$ 239,583	$ 366,233	$ 373,210	$ 380,322	$ 387,571	$ 394,959	$ 402,489	$ 410,164	$ 417,986	$ 425,959
Total	$ 57,093,119	$ 93,200,948	$ 96,422,868	$ 99,483,423	$ 101,643,690	$ 104,569,427	$ 108,509,850	$ 111,765,696	$ 115,232,309	$ 117,900,293
Reserves										
Annual Contribution	$ 450,532	$ 2,362,728	$ 2,203,007	$ 1,487,556	$ 2,100,812	$ 3,471,396	$ 3,678,719	$ 4,147,704	$ 4,931,771	$ 4,074,277
Cumulative Reserve Fund	$ 450,532	$ 2,813,260	$ 5,016,268	$ 6,503,824	$ 8,604,636	$ 12,076,032	$ 15,754,751	$ 19,902,454	$ 24,834,226	$ 28,908,503
Average Energy Costs										
Generation	$ 56.58	$ 52.80	$ 53.27	$ 54.70	$ 55.21	$ 54.58	$ 55.72	$ 56.29	$ 56.98	$ 59.91
PG&E Non Bypassable Charges	$ 126.25	$ 134.65	$ 138.45	$ 141.38	$ 143.08	$ 145.75	$ 149.76	$ 152.68	$ 155.93	$ 157.96
Reserves Contribution	$ 1.01	$ 3.44	$ 3.19	$ 2.13	$ 2.98	$ 4.88	$ 5.12	$ 5.71	$ 6.73	$ 5.50
Average Retail Rate	$ 183.83	$ 190.89	$ 194.92	$ 198.21	$ 201.28	$ 205.21	$ 210.60	$ 214.67	$ 219.64	$ 223.37
CCA Rate Benefit vs. PG&E	-5.0%	-2.0%	-2.0%	-1.8%	-1.8%	-1.7%	-1.8%	-1.7%	-1.9%	-2.3%
Renewable Attributes										
CO2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 13: Pro Forma for base case for Scenario 3

Scenario 3; Base Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	187538.4	290312.6	290697.5	293783.8	296643.1	299660.3	302710.8	305915.8	308899.7	312037.4
Low Income Residential	62536.6	97655.1	98631.7	99663.0	100614.2	101620.3	102636.5	103709.7	104699.5	105746.5
Agriculture	20763.2	29741.1	30038.5	30344.9	30642.2	30948.7	31258.2	31577.1	31886.4	32205.3
Small Commercial	65418.3	99695.5	100692.4	101729.7	102716.4	103743.5	104781.0	105860.3	106887.1	107955.9
Medium Commercial	35938.2	54701.7	55248.7	55832.1	56359.2	56922.8	57492.1	58099.1	58647.7	59234.1
Large Commercial & Industrial	99286.0	150178.1	151679.9	153267.7	154728.6	156275.9	157838.7	159491.0	161011.2	162621.4
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	474088.9246	726254.146	730998.5075	738673.105	745794.1354	753302.8205	760889.7755	768869.4145	776288.0238	784099.6739
Distribution Losses	22282.2	34133.9	34356.9	34717.6	35052.3	35405.2	35761.8	36136.9	36485.5	36852.7
Total Wholesale Load	496371.1	760388.1	765355.4	773390.7	780846.5	788708.1	796651.6	805006.3	812773.6	820952.4
Power Supply Costs										
Market Purchases	$ 17,265,149	$ 27,005,948	$ 27,435,205	$ 28,829,212	$ 29,893,948	$ 30,993,166	$ 32,215,778	$ 33,219,528	$ 34,163,939	$ 36,629,035
Net Renewable Energy	$ 4,601,782	$ 8,369,982	$ 8,745,315	$ 9,071,664	$ 9,369,493	$ 9,725,227	$ 10,090,921	$ 10,523,281	$ 10,876,579	$ 11,316,507
Retail Programs	$ 1,000,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
Resource Adequacy	$ 1,747,318	$ 2,687,268	$ 2,760,967	$ 2,839,912	$ 2,937,585	$ 3,030,028	$ 3,125,350	$ 3,214,568	$ 3,324,939	$ 3,429,368
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 595,000	$ 918,291	$ 931,354	$ 948,485	$ 965,274	$ 982,947	$ 1,001,123	$ 1,020,235	$ 1,039,037	$ 1,058,812
Staff and Other Operational	$ 2,394,892	$ 3,613,745	$ 3,641,208	$ 3,669,295	$ 3,698,020	$ 3,727,402	$ 3,757,457	$ 3,788,204	$ 3,819,662	$ 3,851,848
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 496,371	$ 760,388	$ 765,355	$ 773,391	$ 780,846	$ -	$ -	$ -	$ -	$ -
Total	$ 28,277,020	$ 45,120,383	$ 46,044,167	$ 47,896,720	$ 49,409,928	$ 49,968,770	$ 51,700,629	$ 53,275,818	$ 54,734,155	$ 57,795,570
PG&E Non Bypassable Charges										
PCIA	$ 9,280,819	$ 14,216,417	$ 13,922,005	$ 14,033,054	$ 14,137,490	$ 14,238,360	$ 14,366,028	$ 14,465,468	$ 14,343,108	$ 14,245,658
T&D	$ 40,664,825	$ 65,357,357	$ 68,507,176	$ 71,233,885	$ 73,360,881	$ 75,582,911	$ 77,872,595	$ 80,263,868	$ 82,661,377	$ 85,164,546
Regulatory/Other	$ 8,271,577	$ 12,206,819	$ 12,293,564	$ 12,187,194	$ 11,465,378	$ 11,577,814	$ 12,791,698	$ 12,923,480	$ 13,609,262	$ 13,743,434
Franchise Fee	$ 325,376	$ 497,050	$ 500,043	$ 505,296	$ 510,174	$ 515,316	$ 520,511	$ 525,972	$ 531,056	$ 536,404
PG&E Billing Services	$ 253,315	$ 387,227	$ 394,609	$ 402,133	$ 409,802	$ 417,618	$ 425,584	$ 433,704	$ 441,980	$ 450,415
Total	$ 58,795,912	$ 92,664,869	$ 95,617,397	$ 98,361,562	$ 99,883,725	$ 102,332,018	$ 105,976,416	$ 108,612,493	$ 111,586,783	$ 114,140,457
Reserves										
Annual Contribution	$ 3,751,639	$ 3,925,736	$ 3,466,118	$ 2,384,706	$ 2,545,422	$ 3,610,047	$ 3,561,079	$ 3,596,300	$ 4,183,007	$ 3,106,451
Cumulative Reserve Fund	$ 3,751,639	$ 7,677,375	$ 11,143,494	$ 13,528,200	$ 16,073,622	$ 19,683,670	$ 23,244,749	$ 26,841,049	$ 31,024,056	$ 34,130,507
Average Energy Costs										
Generation	$ 60.87	$ 63.35	$ 64.21	$ 66.07	$ 67.48	$ 67.57	$ 69.19	$ 70.54	$ 71.76	$ 74.97
PG&E Non Bypassable Charges	$ 122.80	$ 126.38	$ 129.58	$ 131.93	$ 132.70	$ 134.61	$ 138.04	$ 140.01	$ 142.49	$ 144.31
Reserves Contribution	$ 7.91	$ 5.41	$ 4.74	$ 3.23	$ 3.41	$ 4.79	$ 4.68	$ 4.68	$ 5.39	$ 3.96
Average Retail Rate	$ 191.58	$ 195.13	$ 198.53	$ 201.23	$ 203.59	$ 206.97	$ 211.91	$ 215.23	$ 219.64	$ 223.24
CCA Rate Benefit vs. PG&E	-2.0%	-1.9%	-2.2%	-2.2%	-2.5%	-2.7%	-2.8%	-3.0%	-3.4%	-3.7%
Renewable Attributes										
CO2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 14: Pro Forma for good case for Scenario 3

Scenario 3; Good Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Accounts										
Residential	39929.3	40328.6	40731.9	41139.2	41550.6	41966.1	42385.8	42809.6	43237.7	43670.1
Low Income Residential	16804.7	16972.7	17142.4	17313.9	17487.0	17661.9	17838.5	18016.9	18197.0	18379.0
Agriculture	683.8	690.6	697.5	704.5	711.5	718.6	725.8	733.1	740.4	747.8
Small Commercial	7183.2	7255.0	7327.6	7400.9	7474.9	7549.6	7625.1	7701.4	7778.4	7856.2
Medium Commercial	402.0	406.0	410.1	414.2	418.3	422.5	426.7	431.0	435.3	439.6
Large Commercial & Industrial	362.5	366.1	369.8	373.5	377.2	381.0	384.8	388.6	392.5	396.4
Street Lightting	1480.7	1495.5	1510.5	1525.6	1540.8	1556.2	1571.8	1587.5	1603.4	1619.4
Total	66846.1	67514.5	68189.7	68871.6	69560.3	70255.9	70958.5	71668.0	72384.7	73108.6
Customer Load (MWh)										
Residential	197957.2	306582.2	307129.9	310388.0	313405.8	316590.6	319810.4	323194.2	326342.9	329655.1
Low Income Residential	66010.8	103080.4	104111.2	105199.8	106203.9	107265.9	108338.6	109471.3	110516.2	111621.3
Agriculture	21916.8	31393.3	31707.3	32030.8	32344.6	32668.0	32994.7	33331.3	33657.9	33994.5
Small Commercial	69052.7	105234.1	106286.5	107381.4	108422.8	109507.0	110602.1	111741.5	112825.2	113953.5
Medium Commercial	37934.8	57740.7	58318.1	58933.9	59490.3	60085.2	60686.1	61326.8	61905.9	62524.9
Large Commercial & Industrial	104801.9	158521.3	160106.5	161782.6	163324.7	164957.9	166607.5	168351.6	169956.3	171655.9
Street Lightting	2608.2	3970.1	4009.8	4051.9	4090.4	4131.3	4172.6	4216.4	4256.5	4299.0
Total Retail Load	500282.3004	766522.2344	771669.2767	779768.2553	787282.3871	795205.9547	803211.9411	811633.1927	819460.8649	827704.2435
Distribution Losses	23513.3	36026.5	36268.5	36649.1	37002.3	37374.7	37751.0	38146.8	38514.7	38902.1
Total Wholesale Load	523795.6	802548.8	807937.7	816417.4	824284.7	832580.6	840962.9	849780.0	857975.5	866606.3
Power Supply Costs										
Market Purchases	$ 27,234,551	$ 43,625,625	$ 44,705,344	$ 47,028,352	$ 49,527,446	$ 51,873,414	$ 54,536,678	$ 56,201,166	$ 57,675,773	$ 61,348,930
Net Renewable Energy	$ 3,419,617	$ 6,324,694	$ 6,626,074	$ 6,875,098	$ 7,009,199	$ 7,250,781	$ 7,483,277	$ 7,883,972	$ 8,198,493	$ 8,671,948
Retail Programs	$ 1,000,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
Resource Adequacy	$ 1,855,522	$ 2,854,182	$ 2,932,923	$ 3,016,618	$ 3,120,084	$ 3,218,038	$ 3,319,038	$ 3,413,607	$ 3,530,502	$ 3,641,140
RPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CAISO Charges	$ 627,874	$ 969,207	$ 983,172	$ 1,001,252	$ 1,018,972	$ 1,037,625	$ 1,056,807	$ 1,076,980	$ 1,096,822	$ 1,117,693
Staff and Other Operational	$ 2,432,020	$ 3,669,993	$ 3,698,019	$ 3,726,674	$ 3,755,973	$ 3,785,934	$ 3,816,575	$ 3,847,913	$ 3,879,967	$ 3,912,757
Startup Financing	$ 169,841	$ 254,762	$ 254,762	$ 254,762	$ 254,762	$ -	$ -	$ -	$ -	$ -
Performance Bond	$ 6,667	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Cost of Credit for Procurement	$ 523,796	$ 802,549	$ 807,938	$ 816,417	$ 824,285	$ -	$ -	$ -	$ -	$ -
Total	$ 37,269,886	$ 60,011,011	$ 61,518,232	$ 64,229,173	$ 67,020,720	$ 68,675,791	$ 71,722,375	$ 73,933,637	$ 75,891,558	$ 80,202,468
PG&E Non Bypassable Charges										
PCIA	$ 4,632,679	$ 5,757,676	$ 4,708,645	$ 3,962,876	$ 2,888,779	$ 1,932,810	$ 860,665	$ 180,650	$ (712,359)	$ (1,701,911)
T&D	$ 42,908,001	$ 68,979,149	$ 72,320,323	$ 75,198,469	$ 77,443,457	$ 79,788,780	$ 82,205,481	$ 84,729,508	$ 87,259,922	$ 89,901,966
Regulatory/Other	$ 8,728,429	$ 12,883,625	$ 12,977,497	$ 12,865,106	$ 12,103,178	$ 12,221,825	$ 13,503,239	$ 13,642,312	$ 14,366,197	$ 14,507,780
Franchise Fee	$ 343,339	$ 524,601	$ 527,870	$ 533,413	$ 538,561	$ 543,986	$ 549,468	$ 555,231	$ 560,595	$ 566,239
PG&E Billing Services	$ 267,047	$ 408,222	$ 416,008	$ 423,944	$ 432,033	$ 440,277	$ 448,680	$ 457,244	$ 465,973	$ 474,870
Total	$ 56,879,494	$ 88,553,273	$ 90,950,343	$ 92,983,808	$ 93,406,007	$ 94,927,679	$ 97,567,533	$ 99,564,947	$ 101,940,328	$ 103,748,945
Reserves										
Annual Contribution	$ 6,095,667	$ 6,378,876	$ 5,430,174	$ 3,663,234	$ 3,041,147	$ 3,481,331	$ 2,579,342	$ 2,302,138	$ 2,802,767	$ 857,905
Cumulative Reserve Fund	$ 6,095,667	$ 12,474,543	$ 17,904,717	$ 21,567,950	$ 24,609,097	$ 28,090,428	$ 30,669,770	$ 32,971,909	$ 35,774,675	$ 36,632,580
Average Energy Costs										
Generation	$ 75.72	$ 79.51	$ 80.94	$ 83.60	$ 86.36	$ 87.60	$ 90.54	$ 92.34	$ 93.86	$ 98.16
PG&E Non Bypassable Charges	$ 112.47	$ 114.31	$ 116.64	$ 118.02	$ 117.41	$ 118.14	$ 120.23	$ 121.42	$ 123.15	$ 124.09
Reserves Contribution	$ 12.18	$ 8.32	$ 7.04	$ 4.70	$ 3.86	$ 4.38	$ 3.21	$ 2.84	$ 3.42	$ 1.04
Average Retail Rate	$ 200.38	$ 202.14	$ 204.62	$ 206.31	$ 207.64	$ 210.12	$ 213.98	$ 216.60	$ 220.43	$ 223.28
CCA Rate Benefit vs. PG&E	-0.5%	-1.3%	-1.9%	-2.4%	-3.2%	-3.8%	-4.4%	-4.7%	-5.2%	-5.7%
Renewable Attributes										
CO2 Emissions [lbs/MWh]	332	312	292	276	260	245	230	215	199	184
Renewable Percentage	32%	34%	36%	38%	40%	41%	43%	45%	47%	48%

Table 15: Supply Mix for bad case for Scenario 1

Scenario 1; Bad Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	29.5	28.8	27.2	26.0	25.1	24.0	23.0	21.8	20.6	19.4
Local Solar	0.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Local Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	22.5	23.4	23.9	23.9	24.5	25.1	25.6	25.9	26.7	27.2
In-state Renewables	0.0	0.0	0.0	0.0	0.9	2.2	3.5	4.7	6.1	7.4
Out-of-state Renewables	9.1	10.1	11.7	13.5	13.9	14.1	14.3	14.5	14.6	14.8

Table 16: Supply Mix for base case for Scenario 1

Scenario 1; Base Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	31.2	30.4	28.8	27.5	26.5	25.5	24.3	23.0	21.8	20.5
Local Solar	0.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Local Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	23.8	24.8	25.3	25.3	26.0	26.5	27.1	27.5	28.2	28.8
In-state Renewables	0.0	0.0	0.0	0.8	2.2	3.5	4.8	6.2	7.6	9.0
Out-of-state Renewables	10.7	11.8	13.6	14.7	14.8	14.9	15.1	15.4	15.4	15.6

Table 17: Supply Mix for good case for Scenario 1

Scenario 1; Good Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	33.0	32.1	30.4	29.1	28.0	26.9	25.7	24.3	23.0	21.7
Local Solar	0.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Local Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	25.1	26.2	26.7	26.7	27.4	28.0	28.6	29.0	29.8	30.4
In-state Renewables	0.0	0.0	0.5	2.0	3.4	4.8	6.2	7.6	9.2	10.7
Out-of-state Renewables	12.4	13.6	15.0	15.5	15.6	15.8	15.9	16.2	16.3	16.5

Table 18: Supply Mix for bad case for Scenario 2

Scenario 2; Bad Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	29.2	28.2	26.7	25.5	24.5	23.5	22.5	21.2	20.0	18.9
Local Solar	0.0	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Local Hydro	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	22.5	23.4	23.8	23.8	24.5	25.0	25.5	25.9	26.6	27.2
In-state Renewables	0.1	0.0	0.3	1.6	2.9	4.1	5.4	6.6	8.0	9.4
Out-of-state Renewables	12.5	12.0	13.4	13.8	13.9	14.1	14.2	14.5	14.6	14.7

Table 19: Supply Mix for base case for Scenario 2

Scenario 2; Base Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	30.9	29.9	28.3	27.0	26.0	24.9	23.8	22.5	21.2	20.0
Local Solar	0.0	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Local Hydro	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	23.8	24.8	25.2	25.2	25.9	26.5	27.0	27.4	28.2	28.8
In-state Renewables	1.0	0.0	1.4	2.8	4.1	5.4	6.8	8.1	9.5	11.0
Out-of-state Renewables	13.2	13.8	14.2	14.6	14.7	14.9	15.1	15.3	15.4	15.6

Table 20: Supply Mix for good case for Scenario 2

Scenario 2; Good Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	32.7	31.6	29.9	28.5	27.5	26.3	25.2	23.8	22.4	21.1
Local Solar	0.0	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Local Hydro	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	25.1	26.1	26.6	26.6	27.4	28.0	28.5	28.9	29.7	30.3
In-state Renewables	1.9	1.0	2.4	3.9	5.3	6.7	8.2	9.5	11.1	12.6
Out-of-state Renewables	13.9	14.6	15.0	15.4	15.6	15.7	15.9	16.2	16.3	16.5

Table 21: Supply Mix for bad case for Scenario 3

Scenario 3; Bad Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	29.2	28.2	26.7	25.4	24.5	23.5	22.4	21.2	20.0	18.8
Local Solar	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Local Hydro	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	22.5	23.4	23.8	23.8	24.5	25.0	25.5	25.9	26.6	27.1
In-state Renewables	3.9	3.7	5.0	6.3	7.6	8.9	10.1	11.4	12.7	14.1
Out-of-state Renewables	12.5	13.0	13.4	13.8	13.9	14.0	14.2	14.4	14.5	14.7

Table 22: Supply Mix for base case for Scenario 3

Scenario 3; Base Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	30.9	29.9	28.3	27.0	25.9	24.9	23.8	22.5	21.2	20.0
Local Solar	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Local Hydro	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	23.8	24.7	25.2	25.2	25.9	26.4	27.0	27.4	28.1	28.7
In-state Renewables	4.8	4.7	6.1	7.5	8.8	10.2	11.5	12.8	14.3	15.7
Out-of-state Renewables	13.2	13.8	14.1	14.6	14.7	14.9	15.0	15.3	15.4	15.6

Table 23: Supply Mix for good case for Scenario 3

Scenario 3; Good Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Supply Mix (Average MW)										
System Power	32.7	31.6	29.8	28.5	27.4	26.3	25.1	23.7	22.4	21.1
Local Solar	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Utility Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Local Hydro	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	25.1	26.1	26.6	26.6	27.3	27.9	28.5	28.9	29.7	30.3
In-state Renewables	5.7	5.7	7.2	8.7	10.1	11.5	12.9	14.3	15.8	17.3
Out-of-state Renewables	13.9	14.6	14.9	15.4	15.5	15.7	15.9	16.2	16.3	16.4

8 Appendix – Assumptions

8.1 Renewable Generator Cost Assumptions

The cost of renewable generation is declining at a faster rate than most projections, with solar (Figure 18) and wind energy leading the charge. Launched in 2011, the original goal of the US Department of Energy's Sunshot Initiative was to reduce solar energy generation costs to roughly 6 cents/kWh, or 75 percent from 2010 to 2020. That goal was surpassed by mid-2015, as NV Energy signed a long term power purchase agreement ("PPA") at a cost of less than 4 cents/kWh, inclusive of Federal incentives.[12] It is likely that the PPA would still come in at under 6 cents/kWh even without subsidies. Wind energy follows a similar story, with utilities signing record low-priced PPAs in 2014, though most of those projects were located in the Midwest.[13]

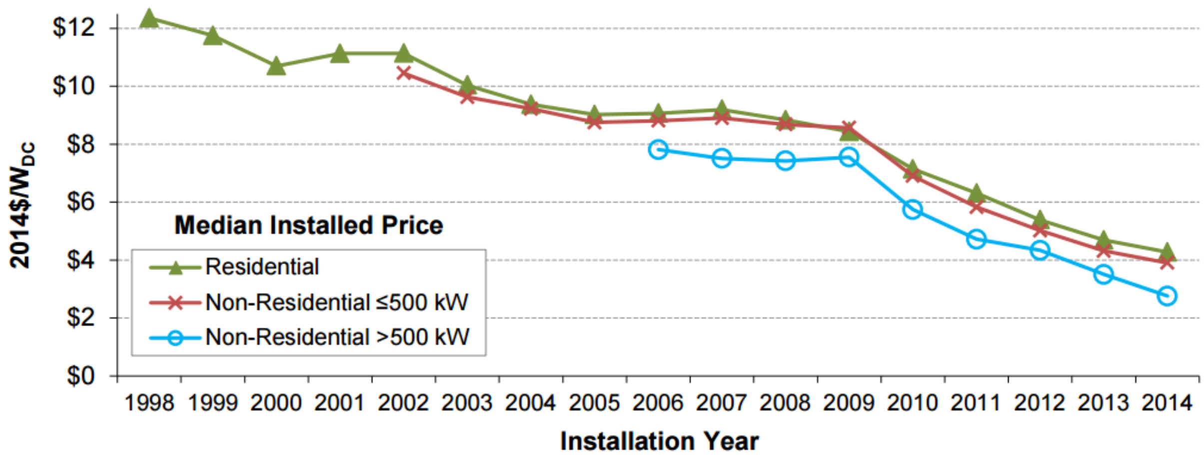

Figure 18: Historical solar generation capacity costs

The decline in solar and wind energy prices can be attributed to two main factors: the manufacturing experience curve and technological improvement. The experience curve suggests that a product becomes cheaper and faster to produce as more of it is manufactured. For solar panels, that meant more efficient use of raw materials and faster installation times. Global solar photovoltaic capacity in 2000 was roughly 1MW. It was nearly 180,000MW by the end of 2014. A lot has been learned about how to build solar panels since then. In that period, residential solar capacity costs have dropped from over $10,000/kW to about $4,000/kW.

In addition to decreasing manufacturing and construction costs, the technology behind these resources improved as well. Newer solar panels are better at converting sunlight to energy than

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[12] http://www.utilitydive.com/news/nv-energy-buys-utility-scale-solar-at-record-low-price-under-4-centskwh/401989/

[13] http://newscenter.lbl.gov/2015/08/10/study-finds-that-the-price-of-wind-energy-in-the-united-states-is-at-an-all-time-low-averaging-under-2-5%C2%A2kwh/

their previous generation counterparts. Wind turbines today can better harvest the energy with larger blades atop higher towers than before. Lower capacity costs in conjunction with higher capacity factors translate into more economically available renewable resources.

Solar energy capacity costs have declined by an average of 6 percent annually since the turn of the century. While it is unlikely that costs will continue to decline at breakneck pace, there are few headwinds preventing further development and increased renewable penetration. The 30 percent solar Investment Tax Credit (ITC), which was slated to ratchet down to 10 percent at the end of 2016 was recently extended by an additional 5 years. The expiration of the subsidy was expected to slow technological progress by several years, but that is no longer the case. Congress also agreed to bring back the wind production tax credit which previously expired at the end of 2014, thus improving economics of wind projects going forward.

The renewable energy cost forecast in the study expects utility scale solar costs to drop to $40/MWh by 2025 and $35/kW by 2030 (Figure 19). Wind energy costs are expected to drop to $50/MWh by 2030. Local solar costs are derived from utility-scale solar costs by calibrating to Humboldt County solar insolation levels, and adding an addition $5/MWh cost to account for the lack of local infrastructure.

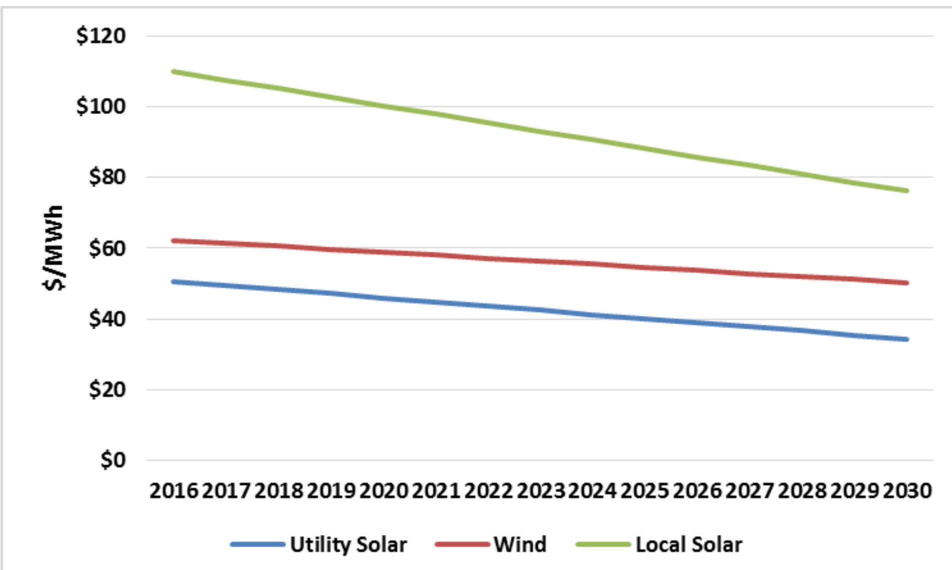

Figure 19: Utility-scale Solar and Wind, and Local (Humboldt County) cost assumptions on a $/MWh basis.

8.2 PG&E Rates Forecast

The Pro Forma includes a forecast for PG&E rates for bundled customers and a forecast for charges that apply to CCA customers, including the Power Charge Indifference Adjustment (PCIA). The market inputs to the PG&E rates forecasts are the same as those used in the hourly price simulations used to determine prospective CCA rates. The rest of the inputs and methodology are described below.

8.2.1 Distribution

Beginning distribution rates for 2016 are based upon PG&E's 2016 ERRA Application. The short term forecast of PG&E distribution rates is based upon PG&E's 2017 General Rate Case (2017

GRC) Application. The 2017 GRC includes the rates that PG&E proposes for 2017 as well as attrition allotments for 2018, and 2019. From 2020 through 2026, distribution rates are projected to follow the inflation estimates used in the base case analysis.

8.2.2 Regulatory

There are numerous regulatory requirements that are included in PG&E rates. Examples include:

- Renewable Portfolio Standards
- Public Purpose Programs
- Competition Transition Charge
- Department of Water Resources Bonds
- Nuclear Decommissioning
- Conservation Incentive Adjustment
- California Climate Credit

Forecasts of these rates are based upon CPUC decisions where applicable, and are consistent in both the PG&E Rate Forecast and PCIA analysis. The starting point in 2016 is based upon PG&E's November, 2016 ERRA Application.

8.2.3 Power Charge Indifference Adjustment / Franchise Fees

A PG&E filing for the Power Charge Indifference Adjustment (PCIA) for 2017 was published on Sep, 1, 2016. For purposes of this analysis this proposed PCIA is used as the starting point. Future years are calculated comparing the PG&E costs to changes in natural gas, power market, and renewable resource prices as supplied and used in the TEA analysis. Generally, as the price of these resources increases, PG&E's recovery amount through the PCIA is reduced. Conversely, if prices were to continue to decline as they have in recent years PG&E's recovery of above market cost would increase.

The Franchise Fee (FFE) is considered constant throughout the forecast period as PG&E's obligations are not likely to change over time. The FFE is an almost negligible amount when compared to the PCIA.

9 Appendix – PG&E Rate History

PG&E Historic Rates (obtained from http://www.pge.com/nots/rates/tariffs/electric.shtml)

Average Cents / kWh	Rate Class	Jan 2001	Jan 2006	Jan 2011	Jan 2015	Jan 2016	Average Annual Nominal Compound Escalation Rate (%) 2001 - 2006	2001 - 2011	2001 - 2016	Last 5 Years	Last 10 Years	Last 1 Year
Residential	**E-1**	12.006	15.439	18.886	20.345	21.183	5.16%	4.63%	3.86%	2.32%	3.21%	4.12%
Commercial	**A-1**	13.110	15.845	17.952	21.152	22.123	3.86%	3.19%	3.55%	4.27%	3.39%	4.59%
	A-6	9.924	13.261	17.313	20.341	21.231	5.97%	5.72%	5.20%	4.16%	4.82%	4.51%
Agricultural	**AG-RA**	15.096	18.520	21.384	23.206	24.920	4.17%	3.54%	3.40%	3.11%	3.01%	7.39%
Industrial	**E-20**	9.334	12.819	13.253	15.216	15.582	6.55%	3.57%	2.36%	3.29%	1.97%	2.41%
Simple Averages		11.894	15.177	17.758	20.052	21.008	5.00%	4.09%	3.87%	3.42%	3.30%	4.77%
Simple Averages (Excl. Industrial)		12.534	15.766	18.884	21.261	22.364	4.70%	4.18%	3.94%	3.44%	3.56%	5.19%

Figure 20: PG&E's historic rates and annual average increases for specific rate classes.

10 Appendix – CCA Timeline

RCEA Phase 1 and 2 Project Timeline -- Updated 7.14.16	Q2 2016			Q3 2016			Q4 2016			Q1 2017			Q2 2017			Q3 2017			Q4 2017		
Workplan Timeline by Task Area	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Administration/Project Management																					
Develop Program workplan/timeline and budget; establish chart of accounts to track expenses																					
Determine internal staff support /roles and responsibilities for start-up activities																					
Begin weekly or bi-weekly team calls; coordinate with all program vendors and staff		ONGOING																			
Determine which municipalities are part of initial enrollment																					
Prepare reports, provide updates for City Council(s) and Board of Supervisors		ONGOING																			
Support JPA Board meetings and CCE admin & operations		ONGOING																			
Technical/Energy Services																					
Prepare Technical Study / Load Data Analysis																					
Meet with Biomass operators/determine supply and contract feasibility																					
Develop program operating budget/proforma; determination of credit needs																					
Determine power supply mix and product options, including inclusion of local biomass projects (i.e. default and volunta																					
Meet with PG&E to review timeline and customer enrollment plans																					
Develop and issue energy supply RFP (scheduling services provided by TEA; ongoing procurement may not require form																					
Negotiate final contract terms with Biomass facilities																					
Prepare and submit program Implementation Plan/Statement of Intent (60-90 day certification)																					
Prepare Utility Service Agreement, Deposit and Bond Posting																					
Complete all regulatory registrations for program compliance (CPUC, CAISO, WREGIS etc); Determine need for filed Integ																					
Negotiate and finalize terms of initial power contracts																					
Support rate design & rate setting (incl PCIA and utility cost comparisons)																					
Develop related energy programs including FIT, NEM, EE, DR et al																					
Coordinate with program staff and all other vendors as needed			ONGOING																		
Communications/Marketing																					
Update FAQs and develop basic program collateral																					
Develop public outreach and marketing plan (including multi-lingual, multi cultural)																					
Branding: program name, logo, core messaging																					
Develop website with translation and opt-out features (Noble I-Frame integration)																					
Community engagement-presentations, public workshops, event tabling, local sponsorships/memberships, key stakeho		ONGOING																			
Begin working with Community Advisory Committee																					
Press outreach/earned media (op-eds, feature stories, local radio and TV)																					
Implement advertising campaign (paid media, social media, et al)																					
Develop call center script/I-Frame/training/Call Center Live in January																					
Prepare customer enrollment notices																					
Manage customer enrollment printing and mailing											#1	#2			#3	#4					
Manage subsequent enrollments and develop ongoing community presence																					
Coordinate with program staff and all other vendors as needed			ONGOING																		

RCEA Phase 1 and 2 Project Timeline -- Updated 7.14.16	Q2 2016			Q3 2016			Q4 2016			Q1 2017			Q2 2017			Q3 2017			Q4 2017		
Workplan Timeline by Task Area	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Data Management/Call Center																					
Finalize data management and call center plans																					
Infrastructure and Application configuration																					
CRM Install and Configuration																					
EDI Certification (utility and bank)																					
Scripting and FAQ Approval																					
IFrame Approval and Configuration																					
IVR Recordings																					
Phone & IVR Programming																					
Hiring Customer Service Representatives																					
Training Customer Service Representatives																					
Call Center Live (end of January)																					
CAISO/OMAR Configuration																					
List of Phase 1 customers																					
1st opt-out period (90 days out)																					
2nd opt-out period (60 days out)																					
Program rates and reports																					
Utility account set up (dead period)																					
Account Switches/Program Live																					
1st Full Billing Cycle																					
3rd opt-out perio (30 days post)																					
4th opt-out perio (60 days post)																					
2nd Full Billing Cycle																					
Settlement Quality Meter Data Reporting																ONGOING					
Billing Administration																ONGOING					
Customer Service																ONGOING					
Finance/Banking																					
Research audititors/accounting services																					
Clarify power supply credit requirements																					
Develop CCE operating budget (based on final votes/load)																					
Determine bank related services and need for additional operating capital																					
Interview and select banking partner (Upmqua Bank or other)																					
Establish CCA deposit and lockbox accounts																					
Coordinate with Noble to ensure daily deposits and controls																					
Determine plan for internal accounting (external bookeeper) and annual audits										ONGOING											

Regulatory/Legislative	
Begin tracking CCE-related regulatory activity and participating in statewide efforts	ONGOING
Begin tracking CCE-related legislative activity and participating in statewide efforts	ONGOING
Register with the CPUC and obtain party status for priority regulatory proceedings	
TEA and Noble to ensure full regulatory/program compliance	
JPA Related	
Review JPA Agreement and CCE Ordinance	
Pass CCA Ordinance/Deadline: June 30, 2016	
Review and amend if needed, CCA related voting structure	
Recommend/update operating polciies related to CCA program	
Approve CCA operating budget	
Hire any additional staff to support effort	
Consider CCA related committees (e.g. citizens advisory committee or technical committee)	
Research and secure any additional insurance policies as may be needed	

11 Glossary

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

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

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

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

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

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

Community Choice Aggregation (CCA): Method available through California law to allow Cities and Counties to aggregate their citizens and become their electric generation provider. Also, the entity (City, City or Joint Powers Agency) providing community choice aggregation services (see Community Choice Energy below).

Community Choice Energy (CCE): A City, County or Joint Powers Agency procuring wholesale power to supply to retail customers. (May be used as a term synonymous with CCA, see above).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Lancaster Choice Energy (LCE): A California CCA exclusively serving the City of Lancaster in Southern California.

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

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

MCE: Formerly Marin Clean Energy - the first CCA in California serving cities within and the counties of Marin, Contra Costa and Napa.

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

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

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

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

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

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

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

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

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

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

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

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

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

The Energy Authority (TEA): A not-for-profit provider of wholesale electricity services to municipal and state agencies throughout the United States.

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

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

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