# ATTACHMENT 1

## Technical Study, including Addendums and Appendices

# Technical Study for Community Choice Aggregation Program in Alameda County

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## List of Acronyms

| | |
|---|---|
| AAEE | Additional Achievable Energy Efficiency |
| CAISO | California Independent System Operator |
| CBA | Collective Bargaining Agreement |
| CCA | Community Choice Aggregation |
| CEC | California Energy Commission |
| CPUC | California Public Utilities Commission |
| EE | Energy Efficiency |
| EBCE | East Bay Community Energy |
| ESPs | Energy Service Providers |
| FY | Fiscal Year |
| GHG | Greenhouse Gas |
| GRP | Gross Regional Product |
| GWh | Gigawatt-hour (= 1,000 MWhs) |
| IOU | Investor-Owned Utility |
| I/T | Information Technology |
| JEDI | Jobs and Economic Impact (model) |
| JPA | Joint Powers Authority |
| kWh | Kilowatt-hour |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NREL | National Renewable Energy Laboratory |
| PCIA | Power Charge Indifference Adjustment |
| PEIR | Programmatic Environmental Impact Report |
| PG&E | Pacific Gas & Electric |
| REC | Renewable Energy Credit |
| REMI | Regional Economic Modeling Inc |
| RPS | Renewable Portfolio Standard |
| roCA | Rest of California |
| SB 350 | Senate Bill 350 |
| TURN | The Utility Reform Network |

# Executive Summary

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses. In June 2014, the Alameda County Board of Supervisors voted unanimously to allocate funding to explore the creation of a Community Choice Aggregation (CCA) Program called East Bay Community Energy (EBCE) and directed County staff to undertake the steps necessary to evaluate the feasibility of a CCA. This feasibility study is in response to this Board Action.

In order to assess whether a CCA is "feasible" in Alameda County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that an Alameda County CCA would have to serve
- Estimates the costs to start-up and operate the CCA
- Considers scenarios with differing assumptions concerning the amount of carbon-free power being supplied to the CCA so as to assess the costs and greenhouse gas (GHG) emissions reductions possible with the CCA
- Includes analysis of in-county renewable generation
- Compares the rates that could be offered by the CCA to PG&E's rates
- Quantitatively explores the rate competiveness to key input variables, such as the cost of natural gas
- Explores what activities a CCA might take with respect to administering customer-side energy efficiency programs
- Calculates the macroeconomic development and employment benefits of CCA formation.

## Loads and Forecast

Figure ES-1 provides a snapshot of Alameda County electric load in 2014 by city and by rate class. As the figure shows, total electricity load in 2014 from Alameda County was approximately 8,000 GWh. The cities of Oakland, Fremont, and Hayward were together responsible for half the county load, with Berkeley, San Leandro, and Pleasanton also contributing substantially. Residential and commercial customers made up the majority of the county load, with smaller contributions from the industrial and public sectors.

To forecast CCA loads through 2030, MRW used a 0.3% annual average growth rate, which is consistent with the California Energy Commission's most recent electricity demand forecast for PG&E's planning area. This growth rate incorporates load reductions from the CCA's energy efficiency programs of about 6 GWh per year from 2021 through 2030. Figure ES-2 shows this forecast by class, with the energy efficiency savings that are included in the forecast indicated by the top (yellow) segment.

**Figure ES-1. PG&E's 2014 Bundled Load in Alameda County by Jurisdiction and Rate Class**

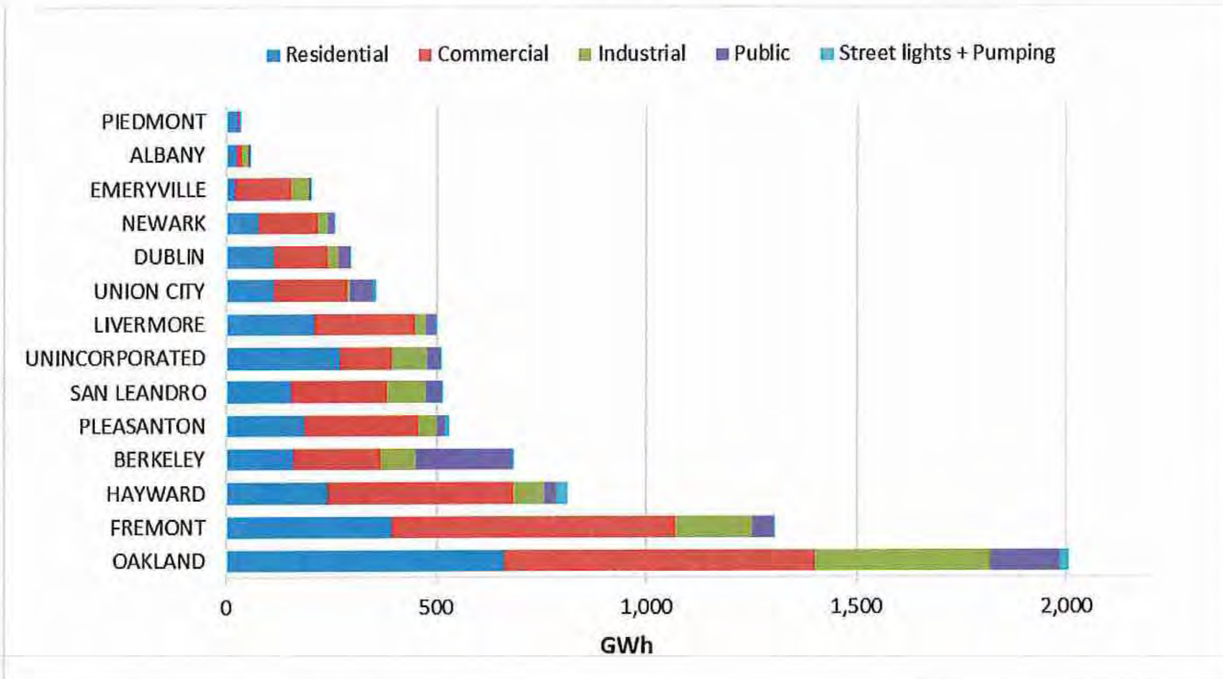
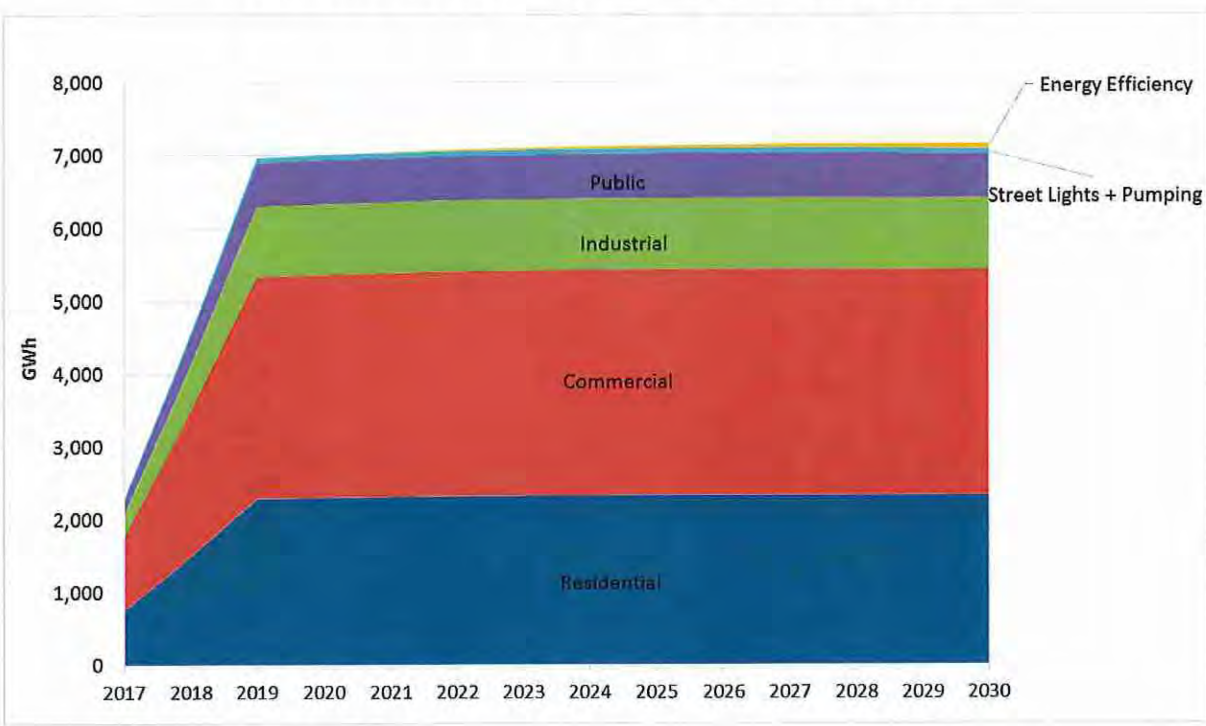



**Figure ES-2: CCA Load Forecast by Class, 2017-2030**



## CCA Power Supplies

The CCA's primary function is to procure power supplies to meet the electrical loads of its customers. This requires balancing energy supply and demand on an hourly basis. It also requires procuring generating capacity (i.e., the ability to provide energy when needed) to ensure that customer loads can be met reliably. By law, the CCA must supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS), requires 33% renewable energy supply by 2020, increasing to 50% by 2030. The CCA may choose to procure a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio (e.g., purchase hydroelectric power rather than power from a fossil fuel generator).

The three supply scenarios that we considered are:

1. **Minimum RPS Compliance:** The CCA meets the state-mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030

2. **More Aggressive:** The CCA's supply portfolio is set at 50% RPS from the first year onward, plus additional amounts of non-RPS compliant large hydro power to reduce GHG emissions

3. **Ultra-Low GHG:** The CCA's supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by the fifth year.

In each case, we assumed that the RPS portfolio was predominately supplied with solar and wind resources, which are currently the lowest cost sources of renewable energy in California. We assumed that solar and wind each contribute 45% of the renewable energy supply. To provide resource diversity and partly address the need for supply at times when solar and wind production are low, we assumed the remaining 10% of renewable supply would be provided by higher-cost baseload resources, such as geothermal or biomass.

### Local Renewable Development

The CCA may choose to contract with or develop renewable projects within Alameda County so as to promote economic development or reap other benefits. For the purpose of this study, we assume that the local renewable power development resulting from the CCA would be largely solar. In developing the hypothetical portfolios, we made conservative assumptions about how much local solar development would occur as a result of the CCA. A renewable potential study performed for the California Public Utilities Commission (CPUC) estimated roughly 300 MW of large solar supply in Alameda County. (Large solar in this study means ground-mounted utility-scale solar farms).[1] This estimate is based on an assessment that five percent of the estimated 6,000 MW of technical potential could be developed, largely as a result of land use conflicts or slope issues that would make solar development unfeasible in certain areas. We assume that over the forecast period through 2030, about 1/3 of the estimated 300 MW large solar supply potential in Alameda County is developed as a result of commitments by the CCA. Additional in-county, small solar projects are assumed to be added at 5-10 MW per year.

[1] At about 8-10 acres per megawatt, this corresponds to 2,400 to 3,000 acres (3.75-4.7 square miles).

As a result of feedback from reviews of the preliminary results, an additional case in which we assume that 50% of the renewables are met with local generation. This case is discussed in Chapter 7 and explored in greater detail in the Addendum.

Additional studies are available and underway[2] assessing in more detail the solar potential in the County, which preliminarily confirm the assumptions used here are conservative (i.e., low). Once formed and operational, the CCA should investigate in greater detail the practical solar potential in the County.

## Rate Results

### Scenario 1 (Simple Renewable Compliance)

Figure ES-3 summarizes the results of Scenario 1. The figure shows the total average cost of the Alameda County CCA to serve its customers (vertical bars) and the comparable PG&E generation rate (line).[3] Of the CCA cost elements, the greatest cost is for non-renewable generation followed by the cost for the renewable generation, which increases over the years according to the RPS standards. Another important CCA customer cost is the Power Charge Indifference Adjustment (PCIA), which is the CPUC-mandated charge that PG&E must impose on all CCA customers. This fee is expected to decrease in most years beginning in 2019 and have less of an impact on the CCA customer rates over time.

Under Scenario 1, the differential between PG&E generation rates and average cost for the Alameda County CCA to serve its customer (*aka* the CCA rates) is positive in each year (*i.e.*, CCA rates are lower than PG&E rates). As a result, Alameda County CCA customers' average generation rate (including contributions to the reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year.

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[2] For example, "Bay Area Smart Energy 2020," available at http://bayarearegionalcollaborative.org/pdfs/BayAreaSmartEnergy2020fin.pdf

[3] All rates are in nominal dollars. Note that these are NOT the full rates shown on PG&E bills. They are only the generation portion of the rates. Other parts of the rate, such as transmission and distribution, are not included, as customers pay the same charges for these components regardless of who is providing their power.

Table ES-1 shows the average annual savings for Residential customers under Scenario 1. The average annual bill for the residential customer on the Alameda County CCA program could average about 7% lower than the same bill on PG&E rates.

**Table ES-1. Scenario 1 Savings for Residential CCA Customers**

| Residential | Monthly Consumption (kWh) | Bill with PG&E ($) | Bill with Alameda County CCA ($) | Savings ($) | Savings (%) |
|---|---|---|---|---|---|
| 2017 | 650 | 147 | 142 | 5 | 3% |
| 2020 | 650 | 160 | 145 | 15 | 9% |
| 2030 | 650 | 201 | 188 | 13 | 6% |

### Scenario 2 (Accelerated RPS)

Under Scenario 2, Alameda County CCA meets 50% of its load through renewable power starting from 2017, while 50% of its non-renewable load is met through hydro-electricity (i.e., overall 50% qualifying renewable. 25% hydro, 25% fossil or market). In this scenario, the differential between PG&E generation rates and Alameda County CCA customer rates is slightly lower than that under Scenario 1, but continues to follow a similar pattern over the years with respect to PG&E rates. As was the case under Scenario 1, because of this positive differential, Alameda County CCA customers' average generation rate (including contributions to the reserve fund) can be lower than PG&E's average customer generation rate in each year under this scenario as well.

The annual bill for a residential customer on the Alameda County CCA program in Scenario 2 could about 6.5% lower than the same bill on PG&E rates (on average over the 2017-2030 study period). This is less than, but close to, bill savings under Scenario 1.

### Scenario 3 (80% RPS by 2021)

Under this scenario, the Alameda County CCA starts with 50% of its load being served by renewable sources in 2017, and increases this at a quick pace to 80% renewable energy content by 2021. In addition, 50% of its non-renewable supply is met through large hydro-electric sources.

The differential between PG&E generation rates and Alameda County CCA customer rates in Scenario 3 is the lowest of the three scenarios, as this scenario has the most expensive supply portfolio (Figure ES-4). However, the expected Alameda County CCA rates continue to be lower than the forecast PG&E generation rates for all years from 2017 to 2030. Although this positive differential still allows for the collection of reserve fund contributions through the CCA's rates in all the years under consideration, between 2026 to 2028 the differential is very small. Similarly, the annual bill for a residential customer on the Alameda County CCA program will be on average only about 3% lower than the same customers on PG&E rates.

**Figure ES-3. Scenario 1 Rate Savings, 2017-2030**

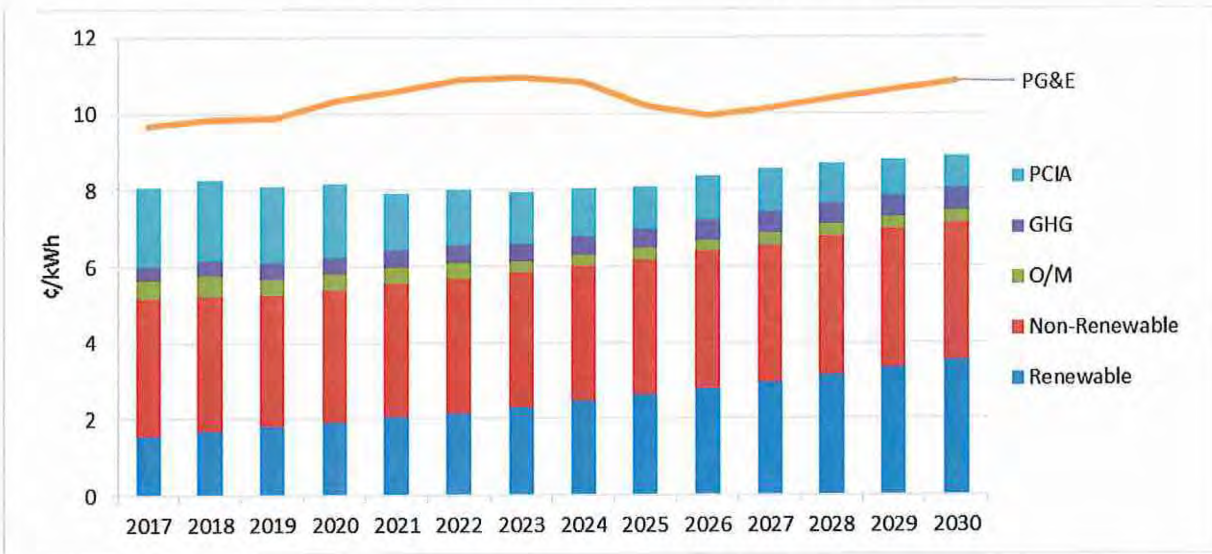
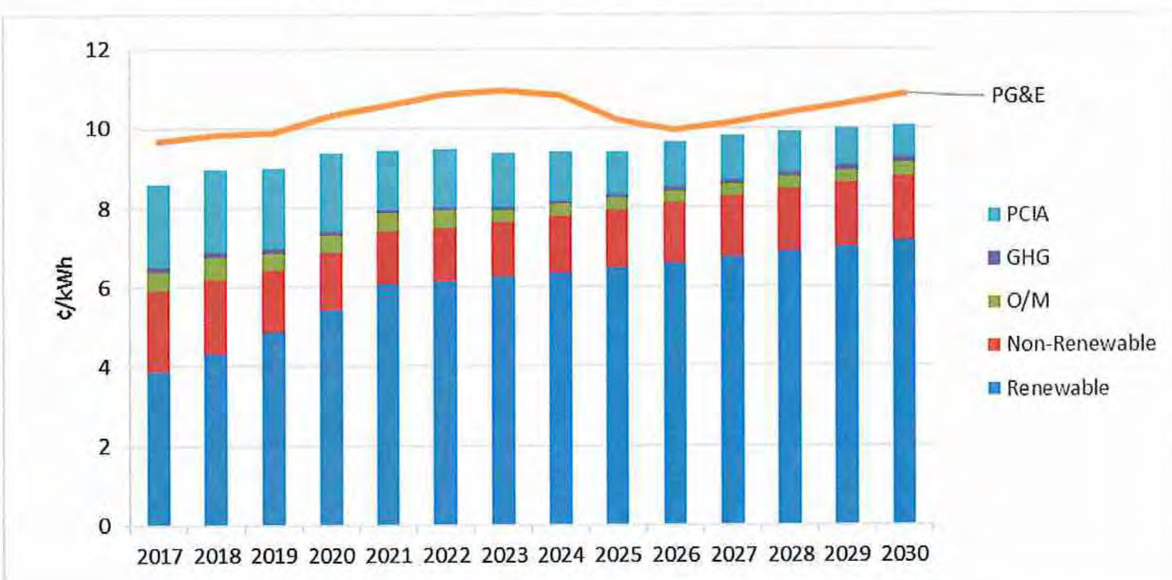



**Figure ES-4. Scenario 3 Rate Savings, 2017-2030**



## Greenhouse Gas Emissions

As modeled, there are no greenhouse gas benefits for Scenario 1—in fact there are net incremental emissions. This is because both the CCA and PG&E are meeting the same RPS requirements, but over 40% of PG&E's supply portfolio is made up of nuclear[4] and large hydro generation, both of which are considered emissions-free.

The Alameda County CCA's GHG emissions under Scenario 2 are much lower than those under Scenario 1. This is due to the higher renewable content in the CCA's generation mix under Scenario 2, but more importantly, the 50% hydro content in the non-renewable generation mix. Figures ES-5 compares the GHG emissions from 2017-2030 for the Alameda County CCA under Scenario 2 with what PG&E's emissions would be for the same load if no CCA is formed. PG&E's GHG emissions are initially comparable to, the CCA's emissions. The expected retirement of Diablo Canyon in 2025 increases PG&E's emissions by approximately 30% in 2025.[5] Following this, PG&E's emissions are expected to decrease from 2026 to 2030 as PG&E procures renewables to meet its mandated RPS goals. However, they still remain higher than the CCA's expected GHG emissions.

The results of Scenarios 1 and 2 illustrate that if the CCA wants to reduce is net carbon emissions, it must include hydroelectric (or other low- or carbon-free resources) in its portfolio.

Note that the analysis assumes "normal" hydroelectric output for PG&E. during the drought years, PG&E's hydro output has been at about 50% of normal, and the utility has made up these lost megawatt-hours through additional gas generation. This means that our PG&E emissions are the PG&E emissions shown here are lower that the "current" emission. If, as is expected by many experts, the recent drought conditions are closer to the "new normal, then PG&E's GHG emissions in the first 8 years would be approximately 30% higher, resulting in GHG savings for Scenario 2 rather than parity.

Similar to Scenarios 1 and 2, under Scenario 3 the Alameda County CCA's GHG emissions first increase from 2017 to 2019 as the CCA is phased in into the entire county. However, in Scenario 3 this increase is partially offset by the increasing renewable content in the CCA's supply mix (Figure ES-6). Thus the CCA's emissions in this scenario grow at a slower rate from 2017 to 2019 than in the first 2 scenarios, then decrease until 80% renewable supply is achieved in 2021, and remain flat thereafter. The CCA's GHG emissions under this scenario are lower than PG&E's expected emissions for the same load if no CCA is formed, for all years except for 2017 for which the emissions are comparable.

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[4] 40% of PG&E portfolio is nuclear and hydro 2017-2024; in 2024 the Diablo Canyon retires and is replaced by gas-fired generation.

[5] Between when this study was conducted and the final report released, PG&E announced its intention to retire Diablo Canyon at the end of its current license and replace it with storage, energy efficiency and renewables. Qualitatively, if Diablo Canyon is replaced with storage etc., PG&E GHG emissions would be significantly lower than the PG&E base case (i.e., the big jump up on PG&E GHG emissions in 2025 would not occur).

**Figure ES-5. Scenario 2 GHG Emissions by Year (PG&E Normal Hydro Conditions)**

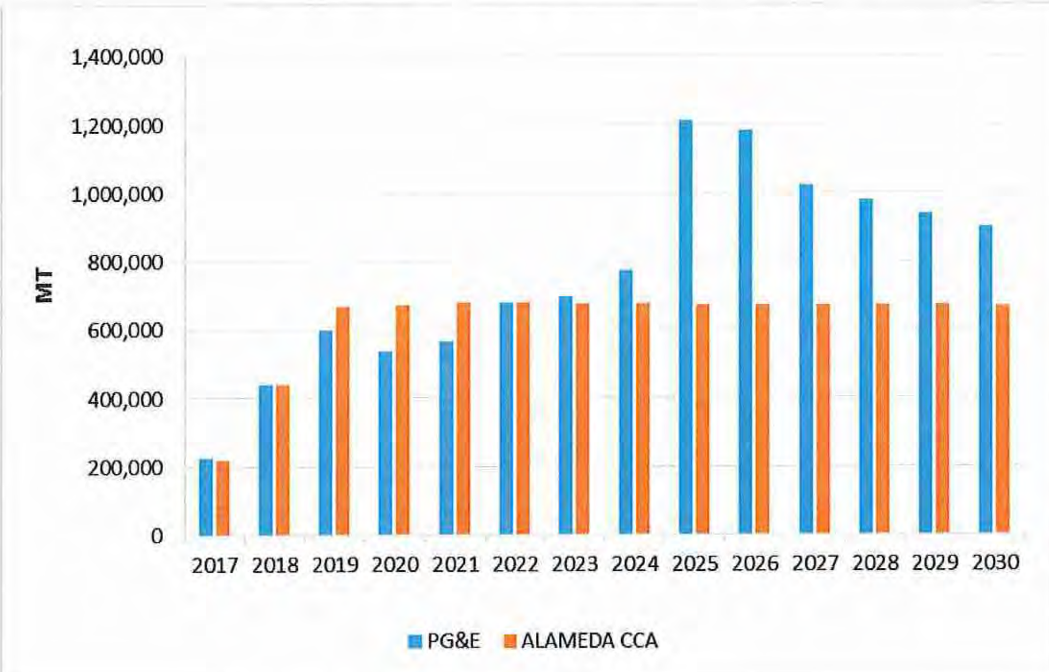
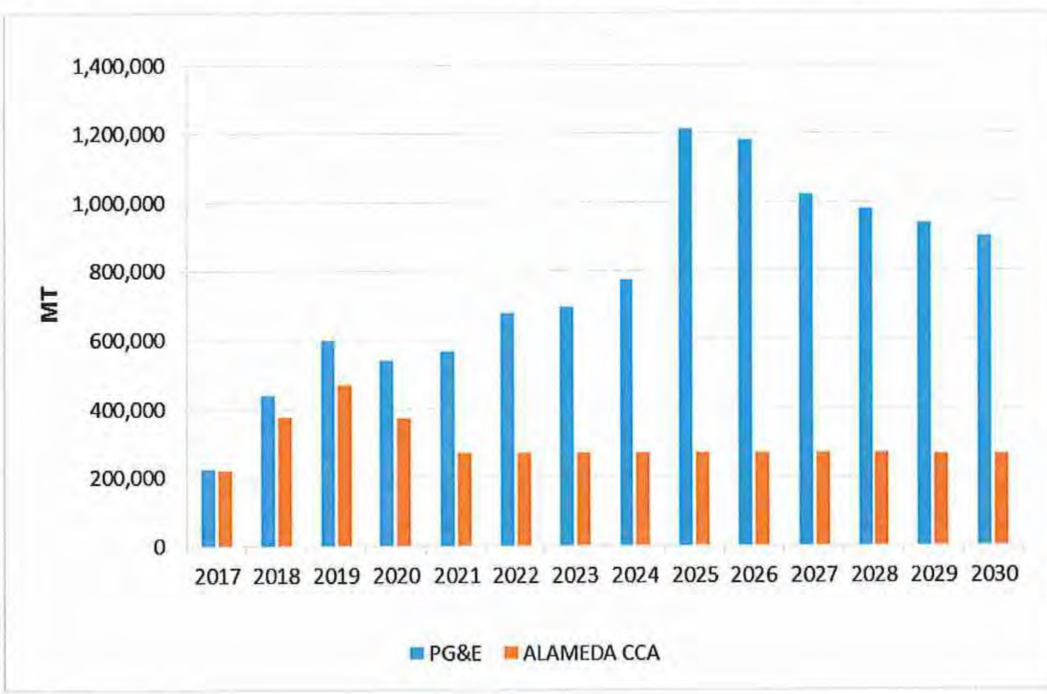



**Figure ES-6. Scenario 3 GHG Emissions by Year PG&E Normal Hydro Conditions**



## Sensitivity Analysis

In addition to the base case forecast described above, MRW assessed alternative cases to evaluate the sensitivity of the results to possible conditions that could impact the Alameda County CCA's rate competitiveness. The key factors are summarized in Table ES-2.

**Table ES-2.**

| Factor | Sensitivity Change |
|---|---|
| Relicensing Diablo Canyon[6] | Increases PG&E's generation rates by ~30%[7] |
| Increased cost of renewable power | 10% higher through 2021, 20% higher in 2021 and 2022, and 30% higher after 2022 |
| High PCIA ("exit fee") | Retains the high PCIA expected in 2018 (2.1¢/kWh) through 2030 |
| High Natural Gas Prices | US Energy Information Administration's High Gas Price Scenario, which is about 60% higher than the base case price |
| Low PG&E Rates | PG&E rates 10% lower than base forecast |
| Stress Scenario | Combined impact of high renewable costs, high PCIA, high gas price and low PG&E rates. |

The sensitivity results are shown as the difference between the annual average PG&E generation rate and the Alameda County CCA rate[8] and are shown in Figure ES-7. Scenario 1 (RPS Compliance) is the least costly scenario for the CCA and therefore has the highest rate differentials under most of the sensitivity cases considered. Scenario 2 (Accelerated RPS), though still quite competitive with PG&E, fares slightly worse, with a rate differential typically about 8% lower than in Scenario 1. Scenario 3 (80% RPS by 2021) has the highest renewable content and is the costliest scenario, with rate differentials much lower than those in the other two scenarios. While Scenario 3 is anticipated to be competitive with PG&E in most cases (on average), the margins are much lower, particularly in the "High Renewable Prices" sensitivity

[6] Between when this study was conducted and the final report released, PG&E announced its intention to retire Diablo Canyon at the end of its current license and replace it with storage, energy efficiency and renewables. Qualitatively, if we replaced DC with storage, energy efficiency and renewables, the net result would be PG&E costs that are between the base PG&E cost and the Diablo Canyon Relicense).

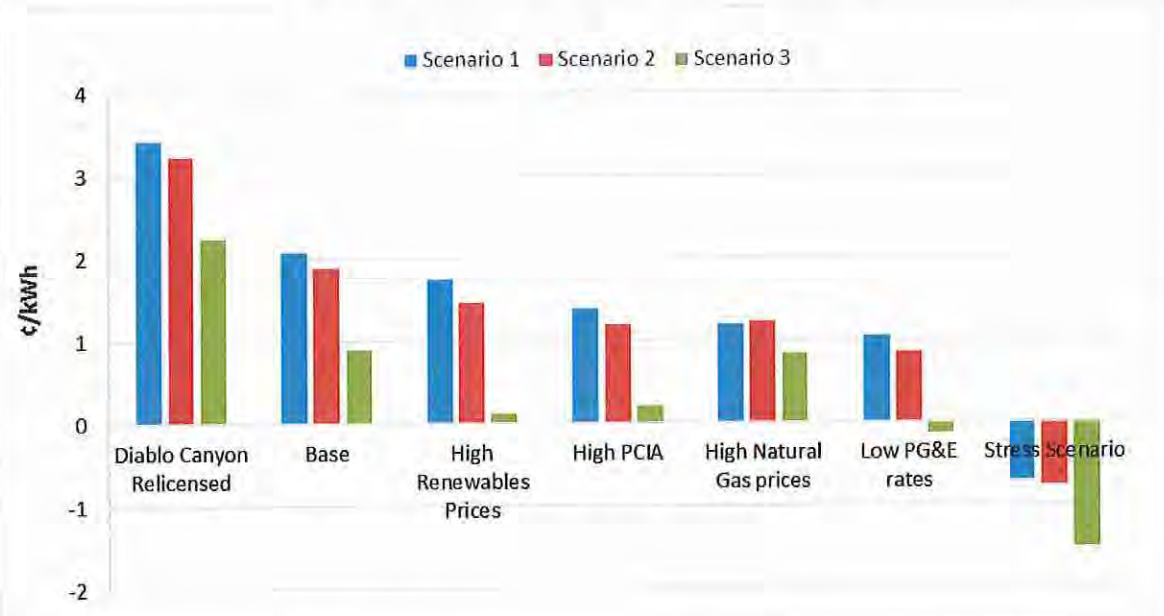
[7] The new cooling system, which would be required per state regulations implementing the Federal Clean Water Act, Section 316(b), would alone have an estimated cost of $4.5 billion. It is because of these very high costs that the base case assumes the that power plant is retired.

[8] The Alameda County CCA rate includes the PG&E exit fees (PCIA charges) that will be charged to CCA customers but does not include the rate adjustment for the reserve fund.

case, and they become negative in the "Low PG&E rates" sensitivity case (*i.e.*, CCA customer rates are higher than PG&E rates).

In the stress case,[9] Alameda County CCA customer rates exceed PG&E customer rates on average over the 2017-2030 period for all three scenarios, with the rate differential being highest in Scenario 3 at -1.5¢/kWh. This is double the Scenario 2 stress case rate differential of -0.75¢/kWh.

**Figure ES-7. Difference Between PG&E Customer Rates and CCA Customer Rates Under Each Sensitivity Case and Supply Scenario, 2017-2030 Average (*i.e.*, positive vertical axis means PG&E rates higher than CCA rates).**




## Macroeconomic and Job Impacts

The local economic development and jobs impacts for the three scenarios were analyzed using the dynamic input-output macroeconomic model developed by Regional Economic Models, Inc. (REMI). The model accounts for not only the impact of direct CCA activities (e.g., construction jobs at a new solar power plant or energy efficiency device installers), but also how the rate savings that County households and businesses might experience with a CCA ripple through the local economy, creating more jobs and regional economic growth.

Table ES-3 and Figure ES-8 illustrate this through high-level results expressed as average annual job changes for the three CCA scenarios. While Scenarios 1 and 2 create nearly identical direct jobs (due to comparable investment in local renewable projects), Scenario 1 creates far more

[9] Stress Scenario assumes the risk cases no favorable to the CCA: High Renewable Prices, High PCIA, High Natural Gas Prices, and Low PG&E rates.

TOTAL jobs. This is due to the higher bill savings under Scenario 1. Scenario 3 creates a few more direct jobs, but far fewer total jobs, due to decreased bill savings as compared to the other two scenarios. As a result, its total job impact is 55 percent of the Scenario 1 total job impact.

**Figure ES-8. Alameda County Total Job Impacts by Scenario**

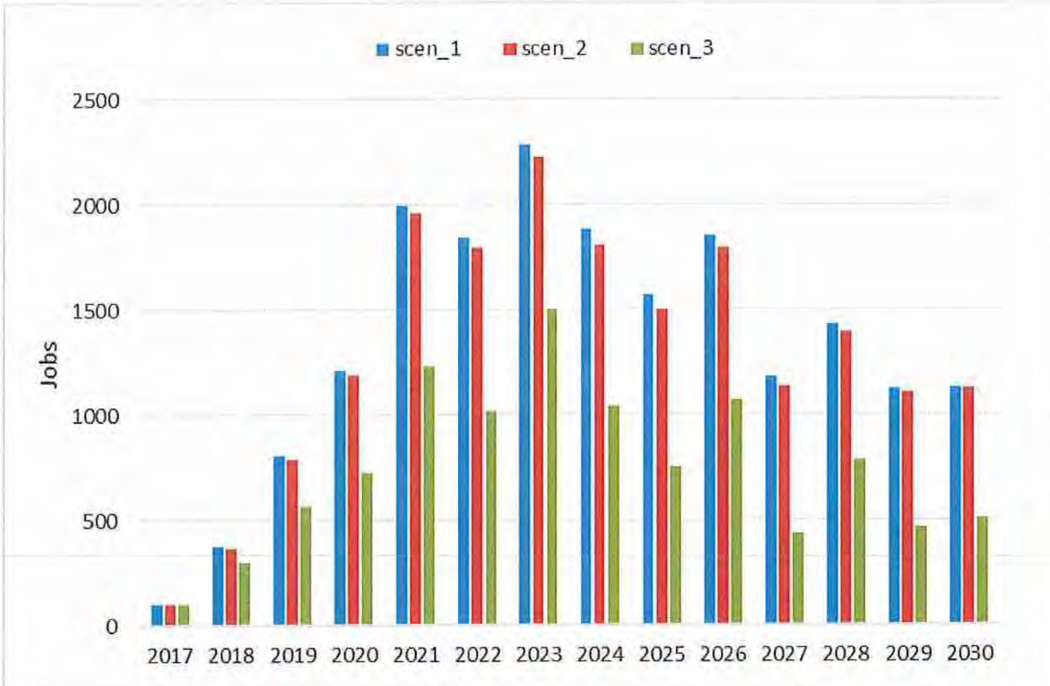
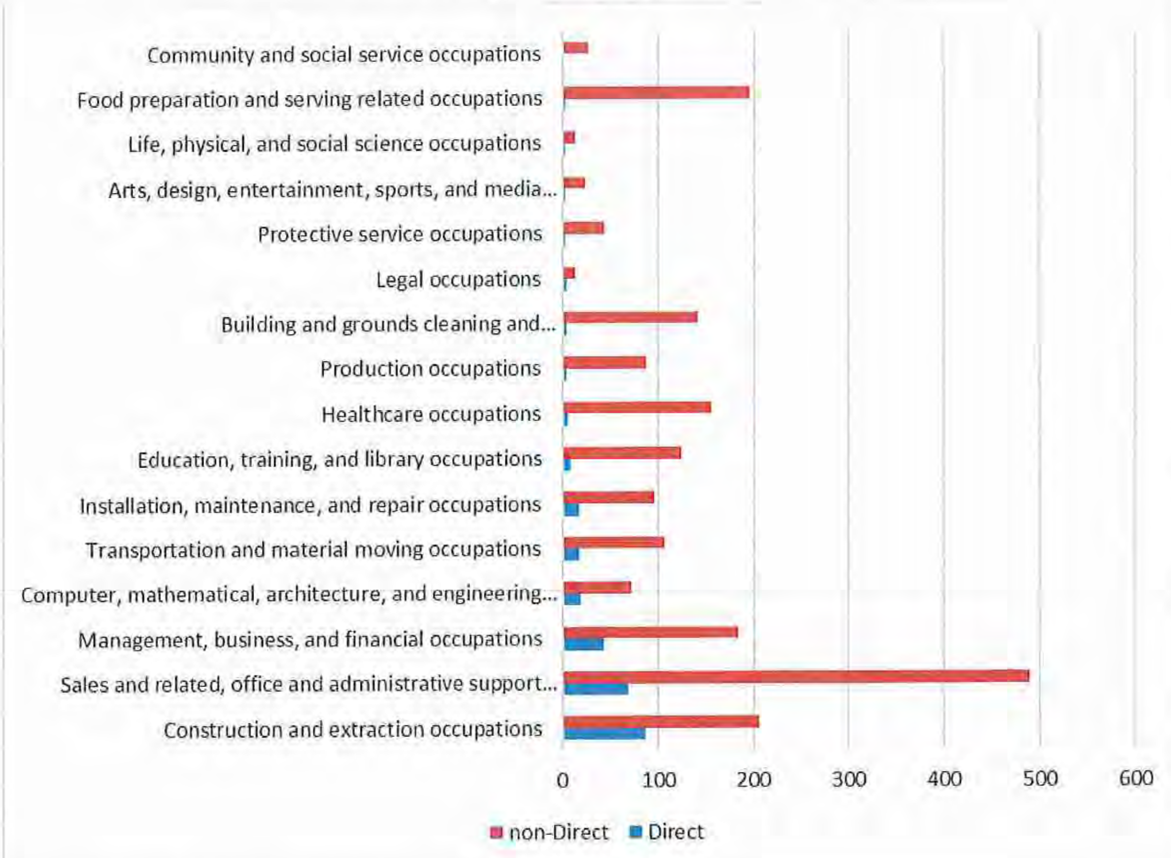



**Table ES-3. Average Annual Jobs created in Alameda County by the CCA – Direct and Total Impacts**

| | 2017 – to – 2030 | | County Impacts | |
|---|---|---|---|---|
| CCA Scenario | Local Capture on RE investments (billion$) | Bill Savings (billion$) | Average Annual DIRECT Jobs | Average Annual TOTAL Jobs |
| 1 | $0.42 | $1.57 | 165 | 1,322 |
| 2 | $0.42 | $1.51 | 166 | 1,286 |
| 3 | $0.45 | $0.52 | 174 | 731 |

The economic activity generated by the CCA results in incremental employment in a variety of sectors. Figure ES-9 shows the job impacts (direct and indirect) by category for Scenario 1 in the year 2023 (the year of maximum impact). It may be surprising that the non-direct stage of economic stimulation for the county creates a more pronounced set of occupational opportunities due to the magnitude of net rate savings benefitting all customer segments within the county.

**Figure ES-9. Occupational Impacts Scenario 1, 2023**




## Energy Efficiency

The three cases each assumed approximately 6 GWh of annual incremental energy efficiency savings directly attributable to CCA efficiency program administration. This value is based on forecasts from the California Energy Commission, and take into account the savings being achieved/allocated to PG&E as well as the mandates from Senate Bill 350.

A CCA has a number of options with respect to administering energy efficiency programs. First, it can rely upon PG&E to continue to all energy efficiency activities in its area, with some input to insure that monies collected from CCA customers flow back to the area. This is the path that two of the four active California CCAs have chosen (Sonoma Clean Power and Lancaster Choice Energy). Second, the CCA can apply to the CPUC to use monies collected in PG&E rates for energy efficiency programs and administration. These CCA efficiency programs can be for CCA customers only or for all customers in the CCA region, no matter their power provider. If the CCA chose the latter path, greater funds are available (including for natural gas efficiency programs). MCE Clean Energy has chosen this latter path. Our modeling assumed the more conservative former one (i.e., offer efficiency programs to only CCA-served residents and businesses). Third, the CCA supplement or supplant these funds though revenues collected by the CCA.

## Conclusions

Overall, a CCA in Alameda County appears favorable. Given current and expected market and regulatory conditions, an Alameda County CCA should be able to offer its residents and business electric rates that are a cent or more per kilowatt-hour (~8%) less than that available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of renewable energy are assumed in the CCA portfolio (Scenario 3), combined with other negative factors, do PG&E's rates become consistently more favorable than the CCAs.

An Alameda County CCA would also be well positioned to help facilitate greater amounts renewable generation to be installed in the County. While the study assumed a relatively modest amount for its analysis—about 175 MW, other studies suggest that greater amounts are possible. Because the CCA would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would actually occur with a CCA in the County than without it.

The CCA can also reduce the amount greenhouse gases emitted by the County, but only under certain circumstances. Because PG&E's supply portfolio has significant carbon-free generation (large hydroelectric and nuclear generators), the CCA must contract for significant amounts of carbon-fee power above and beyond the required qualifying renewables in order to actually reduce the county's electric carbon footprint. For example, even assuming that the CCA implements a portfolio with 50% qualifying renewables and meets the 50% of the remaining power with carbon-free hydropower, it would only then just barely result in net carbon reductions. However, the extent to which GHG emissions reductions could occur is also a function of the amount of hydroelectric power that PG&E is able to use. If hydro output (continues) to be below historic normal levels, then the CCA should be able to achieve GHG savings, as long as it is also contracting for significant amounts of carbon-free (likely hydroelectric) power. Therefore, if carbon reductions are a high priority for the CCA, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed.

A CCA can also offer positive economic development and employment benefits to the County. At the peak, the CCA would create approximately 2300 new jobs in the region. The large amount for be for construction trades, totaling 440 jobs. What may be surprising is that much for the jobs and economic benefit come from reduced rates. Residents, and more importantly businesses, can spend and reinvest their bill savings, and thus generate greater economic impacts.

# Chapter 1: Introduction

The Alameda County Board of Supervisors voted unanimously in June, 2014 to allocate funding to explore the creation of a Community Choice Aggregation (CCA) Program and directed County staff to undertake the steps necessary to evaluate the feasibility of a CCA. This Technical Study is in response to that Board Action.

## What is a CCA?

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses.

Under existing rules administered by the California Public Utilities Commission PG&E must use its transmission and distribution system to deliver the electricity supplied by a CCA in a non-discriminatory manner. That is, it must provide these delivery services at the same price and at the same level of reliability to customers taking their power from a CCA as it does for its own full-service customers. By state law, PG&E also must provide all metering and billing services, its customers receiving a single electric bill each month from PG&E, which would differentiate the charges for generation services provided by the CCA as well as charges for PG&E delivery services. Money collected by PG&E on behalf of the CCA is remitted in a timely fashion (e.g., within 3 business days).

As a power provider, the CCA must abide by the rules and regulations placed on it by the state and its regulating agencies, such as maintaining demonstrably reliable supplies and fully cooperating with the State's power grid operator. However, the State has no rate-setting authority over the CCA; the CCA may set rates as it sees fit so as to best serve its constituent customers.

Per California law, when a CCA is formed all of the electric customers within its boundaries will be placed, by default, onto CCA service. However, customers retain the right to return to PG&E service at will, subject to whatever administrative fees the CCA may choose to impose.

California currently has four active CCA Programs: MCE Clean Energy, serving Marin County and selected neighboring jurisdictions; Sonoma Clean Power, serving Sonoma County, CleanPowerSF, serving San Francisco City and County, and Lancaster Choice Energy, serving the City of Lancaster (Los Angeles County). Numerous other local governments are also investigating CCA formation, including Los Angeles County, San Mateo County, Monterey Bay region, Santa Barbara, San Luis Obispo and Ventura Counties; and Lake County to name but a few.

## Assessing CCA Feasibility

In order to assess whether a CCA is "feasible" in Alameda County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that an Alameda County CCA would have to serve.
- Estimates the costs to start-up and operate the CCA.

- Considers three scenarios with differing assumptions concerning the amount of carbon-free power being supplied to the CCA so as to assess the costs and greenhouse gas emissions reductions possible with the CCA.
- Includes analysis of in-county renewable generation.
- Compares the rates that could be offered by the CCA to PG&E's rates.
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- Explores what activities a CCA might take with respect to administering customer-side, energy efficiency programs
- Calculates the macroeconomic development and employment benefits of CCA formation.

This study was conducted by MRW & Associates, LLC. MRW was assisted by Tierra Resource Consultants, who conducted all the research and analysis related to energy efficiency. MRW was also assisted by Economic Development Research Group, which conducted all of the macroeconomic and jobs analysis contained in the study.

This Study is based on the best information available at the time of its preparation, using publicly available sources for all assumptions to provide an objective assessment regarding the prospects of CCA operation in the County. It is important to keep in mind that the findings and recommendations reflected herein are substantially influenced by current market conditions within the electric utility industry, which are subject to sudden and significant changes.

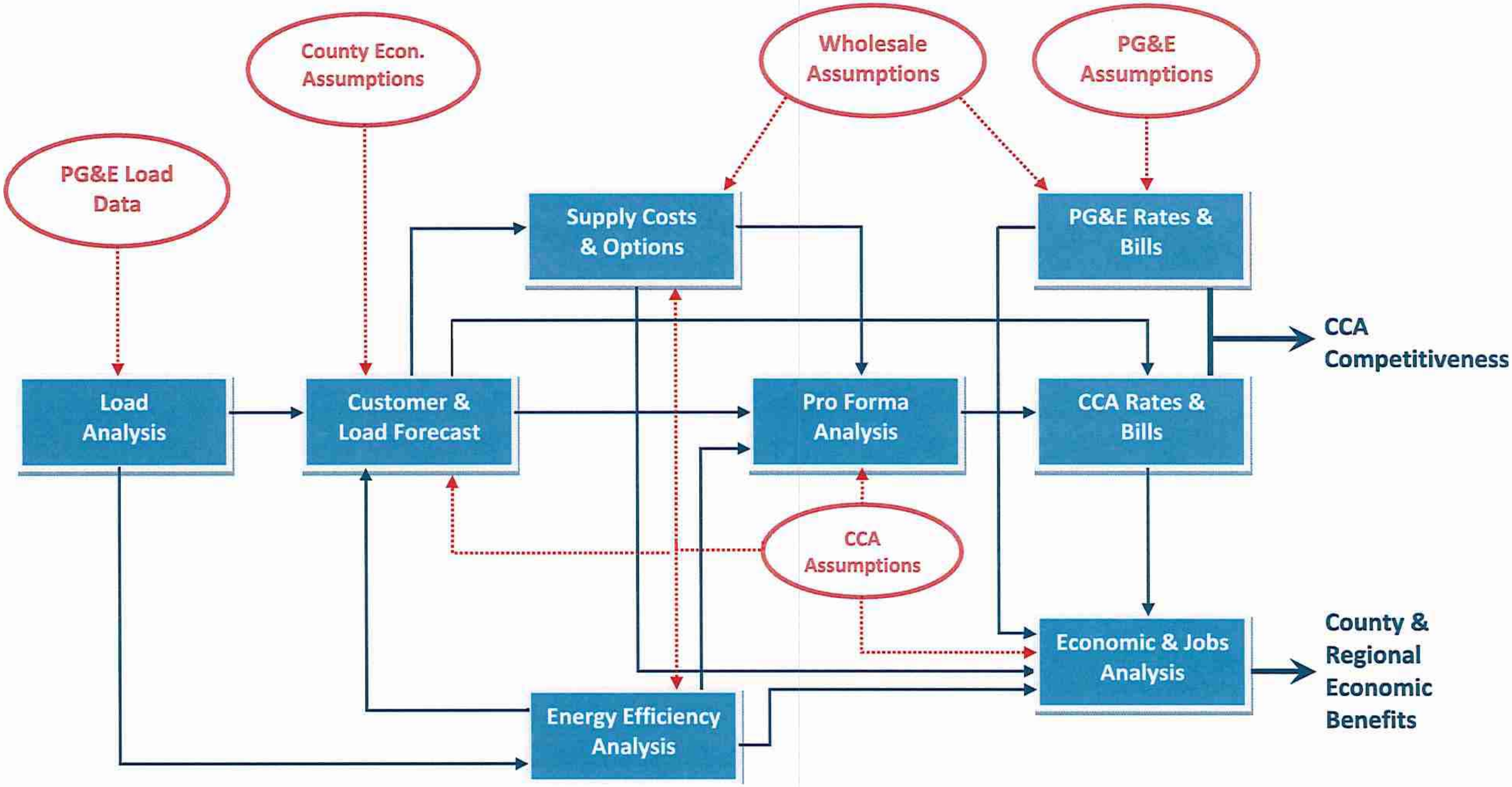
# Chapter 2: Economic Study Methodology and Key Inputs

The section summarizes the key inputs and methodologies used to evaluate the cost-effectiveness and cost-competitiveness of the CCA under different scenarios. It considers the requirements that an Alameda County CCA would need to meet, the resources that the County has available or could obtain to meet these requirements, and the PG&E rates that the CCA would be competing against. It also describes the pro forma analysis methodology that is used to evaluate the financial feasibility of the CCA.

Understanding the interrelationships of all the tasks and using consistent and coherent assumptions throughout are critical to delivering a quality work product. Figure 1 shows the analysis elements (blue boxes) and major assumptions (red ovals) and how they relate to each other. As the figure illustrates, there are numerous integrations between the tasks. For example, the load forecast is a function of not only the load analysis, but also of projections of economic activity in the county and outcome of the energy efficiency analysis.

Two important points are highlighted in this figure. First, it is critical that wholesale power market and prices assumptions are consistent between the CCA and PG&E. While there are reasons that one might have lower or higher costs than the other for a particular product (e.g., CCAs can use tax-free debt to finance generation projects while PG&E cannot), both will participate in the wider Western US gas and power markets and therefore will be subject to the same underlying market forces. To apply power cost assumptions to the CCA than to PG&E, such as simply escalating PG&E rates while deriving the CCA rates using a bottom-up approach, will result in erroneous results. Second, virtually all elements of the analysis feed into the economic and jobs assessment. As is described in detail in Chapter 5, the Study here uses a state-of-the art macroeconomic model that can account for numerous activities in the economy, which allows for a much more comprehensive—and accurate—assessment than a simple input-output model.

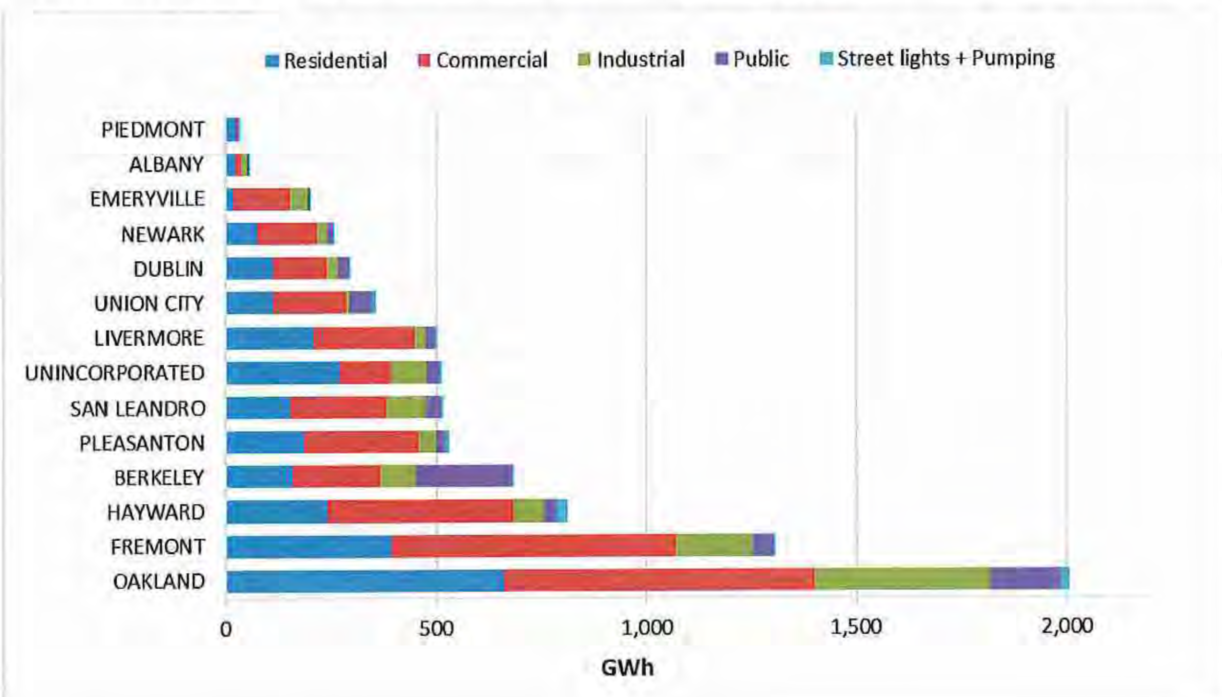
**Figure 1. Task Map**



## Alameda County Loads and CCA Load Forecasts

MRW used PG&E bills from 2014 for all PG&E bundled service customers within the Alameda County region as the starting point for developing electrical load and peak demand forecasts for the Alameda County CCA program.[10] Figure 2 provides a snapshot of Alameda County load in 2014 by city and by rate class. PG&E's total electricity load in 2014 from Alameda County bundled customers was approximately 8,000 GWh.[11] The cities of Oakland, Fremont, and Hayward were together responsible for half the county load, with Berkeley, San Leandro, and Pleasanton also contributing substantially. Residential and commercial customers made up the majority of the county load, with smaller contributions from the industrial and public sectors (Figure 3). This same sector-level distribution of load is also apparent at the jurisdictional level for most cities, with the exception of the city of Berkeley. The city of Berkeley's load has a significant public-sector footprint due to the presence of the University of California, Berkeley.

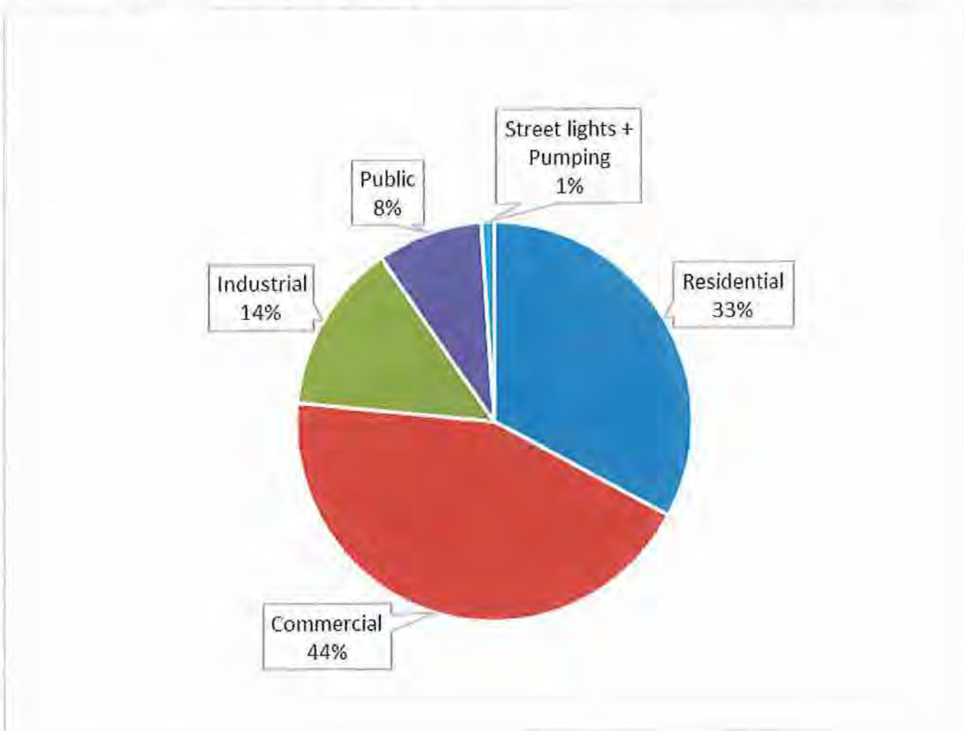
**Figure 2. PG&E's 2014 Bundled Load in Alameda County by Jurisdiction and Rate Class**




[10] Detailed monthly usage data provided by PG&E to Alameda County.

[11] As determined from bill data provided by PG&E. "Bundled" load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers and load met by customer self-generation.

**Figure 3. PG&E's 2014 Bundled Load in Alameda County by Rate Class**

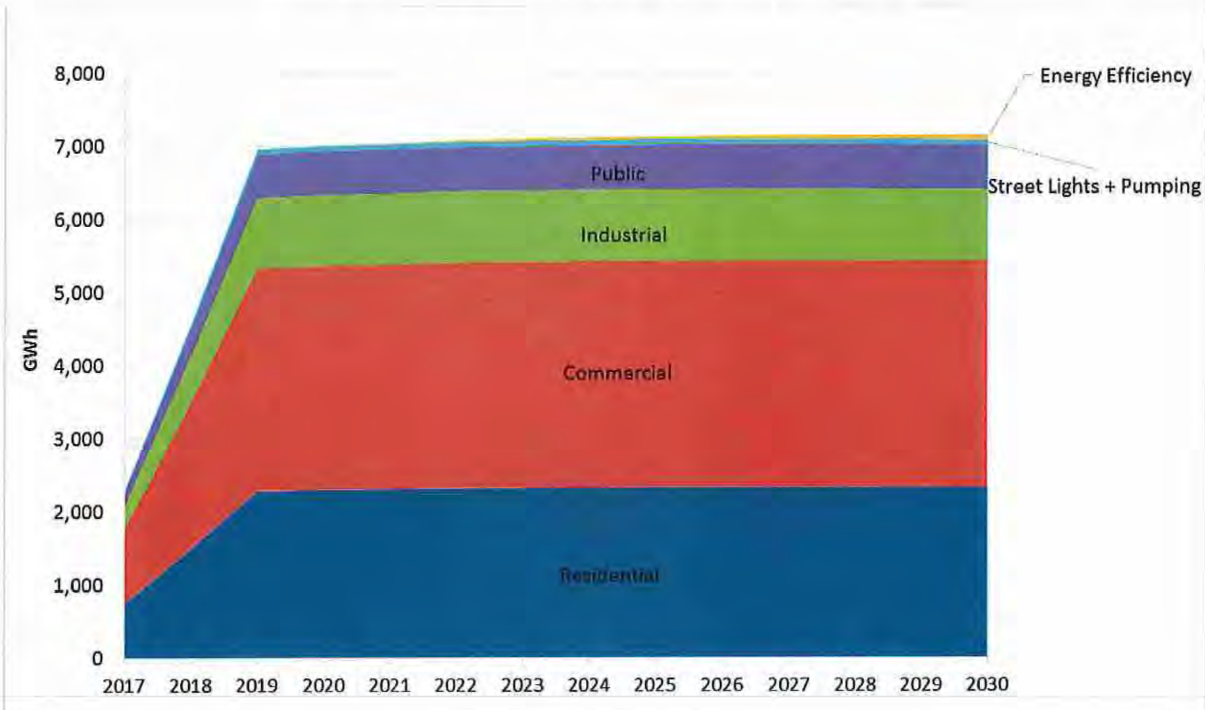



To estimate CCA loads from PG&E's 2014 bundled loads, MRW assumed a CCA participation rate of 85% (*i.e.*, 15% of customers opt to stay with PG&E) and a three-year phase in period from 2017 to 2019, with 33% of potential CCA load included in the CCA in 2017, 67% in 2018, and 100% in 2019. To forecast CCA loads through 2030, MRW used a 0.3% annual average growth rate, consistent with the California Energy Commission's most recent electricity demand forecast for PG&E's planning area.[12] This growth rate incorporates load reductions from energy efficiency of about 6 GWh per year from 2021 through 2030.

The CCA load forecast is summarized in Figure 4, which shows annual projected CCA loads by class, with the energy efficiency savings that are included in the forecast indicated by the top (yellow) segment.

[12] California Energy Commission. Form 1.1c California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, Mid AAEE Savings. January 20, 2015 http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/LSE_and_BA/

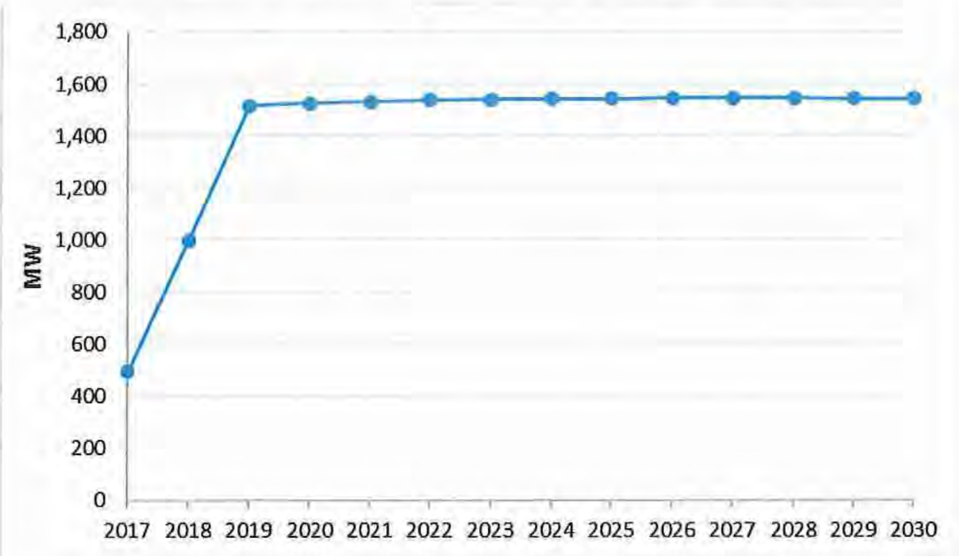
**Figure 4: CCA Load Forecast by Class, 2017-2030[13]**




To estimate the CCA's peak demand in 2014, MRW multiplied the load forecast for each customer class by the PG&E's 2014 hourly ratio of peak demand to load for that customer class.[14] MRW extended the peak demand forecast to 2030 using the same growth rates used for the load forecast. (Peak demand is the maximum amount of power the CCA would use at any time during the year. It is measured in megawatts (MW). It is important because a CCA must have enough power plants on (or contracted with) at all times to meet the peak demand.) This forecast is summarized in Figure 5.

[13] Load forecasted assumes 85% participation.
[14] Data obtained from PG&E's dynamic load profiles for Public, Industrial, Commercial and Residential customers (https://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml) and static load profiles for Pumping and Streetlight customers (https://www.pge.com/nots/rates/2016_static.shtml#topic2).

**Figure 6. CCA Peak Demand Forecast, 2017-2030**




## Energy Efficiency

The assessment of energy efficiency potential in Alameda County completed for this feasibility study used outputs from the 2013[15] and 2015[16] *Energy Efficiency Potential and Goals* studies developed by the CPUC. These CPUC studies define the technical and economic potential for energy efficiency in PG&E's service territory. They also determine the market potential used to set goals and budgets for PG&E's energy efficiency programs.[17] Because of its size, varied economy, diverse demographics, and range of climates, it is likely that both energy use characteristics and the potential for energy efficiency in Alameda County is consistent with the potential for energy efficiency in PG&E's overall service territory, with some exceptions, such as a reduced presence of agricultural and oil extraction loads found elsewhere in the state. Based on these consistencies, this analysis concludes that the energy efficiency potential for electricity in PG&E's overall service territory as presented in the CPUC studies can be allocated to Alameda County in proportion to overall electricity sales, which average approximately 7.5% of total annual PG&E electricity sales.

Using this approach to interpreting the output from CPUC potential studies, Table 1 provides a range of estimates of technical and economic potential in Alameda County for a forecast horizon from the 2017 to 2024. This provides a general indication of the total amount of energy efficiency potential that exists in Alameda County that PG&E and any CCA administered programs would be serving.

[15] 2013 California Energy Efficiency Potential and Goals Study, Final Report. Prepared for the California Public Utilities Commission by Navigant Consulting, Inc. February 14, 2014
[16] Energy Efficiency Potential and Goals Study for 2015 and Beyond, Stage 1 Final Report. Prepared for the California Public Utilities Commission by Navigant Consulting, Inc. Reference No.: 174655, September 25, 2015
[17] See Appendix A for a discussion of technical, economic, and market potential.

**Table 1. Alameda County Average Technical and Economic Energy Efficiency Potential**

| Metric | Technical Potential | | Economic Potential | |
|---|---|---|---|---|
| **Range (% of sales)** | 21% | 16% | 18% | 15% |
| **Potential (GWh)** | 1,623 | 1,237 | 1,391 | 1,159 |

Table 2 provides a forecast of the market potential for energy efficiency based on a similar analysis market forecasts from the CPUC potential studies. The row labeled "PG&E Goals" represents Alameda County's share of the market potential forecast which formed the basis for PG&E's 2015 energy efficiency program portfolio savings targets.[18] That is, because Alameda is in PG&E's service area, it provides, and will continue to provide, energy efficiency programs to Alameda county residents and businesses. This row shows this amount. The row labeled "High Savings Scenario" represents the energy efficiency savings attributable to Alameda County in the CPUC potential study's high savings scenario.[19] The row labelled "Incremental Potential" is the difference between PG&E's 2015 portfolio goals for Alameda County and the high savings scenario for the County. This row represents the total market potential that could be served by CCA administered programs. The forecast presented in Table 2

**Table 2. Alameda County Incremental Energy Efficiency Market Potential (GWh)[20]**

| Year | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|
| Alameda Co. Component of PG&E Goals | 25.9 | 35.8 | 24.6 | 29.4 | 41.1 | 48.2 | 50.0 | 25.9 |
| Alameda Co. of High Savings Scenario | 44.2 | 59.8 | 56.6 | 65.6 | 71.7 | 84.2 | 88.4 | 44.2 |
| Incremental Potential | 18.3 | 24.0 | 32.0 | 36.3 | 30.6 | 36.0 | 38.4 | 18.3 |

While there are countless opportunities and approaches to achieve energy efficiency, several examples of technologies and programs that will yield savings above what is being targeted through the current portfolio of PG&E programs operating in Alameda County are listed below. This includes initiatives that might compliment and leverage existing technologies or programs, or highlight emerging opportunities that are in design or early deployment.

- High efficiency LED lighting initiatives targeting high lumen per watt technologies.

[18] Net GWh, as defined by the CEC Mid Additional Achievable Energy Efficiency (AAEE) forecast

[19] Referred to as the High AAEE Potential Scenario

[20] Savings values do not include energy efficiency potential associated with building codes, appliance standards, or estimates for the agricultural or mining market sectors.

- Advanced controls for lighting and platforms that integrate advanced building information & energy management systems.
- Increased use of over 50 market ready funding and financing products that can be used to implement sustainability projects in all market sectors.
- High Opportunity Programs and Projects (HOPPs) being submitted in response to AB802, such as the Residential Pay-for-Performance HOPP being proposed by PG&E may provide an opportunity to drive higher participation Property Assessed Clean Energy (PACE) programs currently operating throughout Alameda County.

## CCA Supplies

The CCA's primary function is to procure supplies to meet the electrical loads of its customers. This requires balancing energy supply and demand on an hourly basis. It also requires procuring generating capacity (i.e. the ability to provide energy when needed) to ensure that customer loads can be met reliably.[21] In addition to simply meeting the energy and capacity needs of its customers, the CCA must meet other procurement objectives. By law, the CCA must supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS), requires 33% renewable energy supply by 2020, increasing to 50% by 2030. The CCA may choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCA may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the county.

The Alameda County CCA would be taking over these procurement responsibilities from PG&E for those customers who do not opt out of the CCA to remain bundled customers of PG&E. To retain customers, the CCA's offerings and rates must compete favorably with those of PG&E.

The CCA's specific procurement objectives, and its strategy for meeting those objectives, will be determined by the CCA through an implementation plan, startup activities and ongoing management of the CCA. The purpose of this study is to assess the feasibility of establishing a CCA to serve Alameda County based on a forecast of costs and benefits. This forecast requires making certain assumptions about how the CCA will operate and the objectives it will pursue. To address the uncertainty associated with these assumptions, we have evaluated three different supply scenarios and have generally made conservative assumptions about the ways in which the CCA would meet the objectives discussed above. In no way does this study prescribe actions to be taken by the CCA should one be established.

The three supply scenarios that we considered are:

[21] The California Public Utilities Commission (CPUC) requires that load serving entities like CCAs demonstrate that they have procured resource adequacy capacity to meet at least 115% of their expected peak load. Since Alameda falls within the Greater Bay Area Local Reliability Area, it must also meet its share of local resource adequacy requirements.

1. **Minimum RPS Compliance:** The CCA meets the state-mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030;

2. **More Aggressive:** The CCA's supply portfolio is set at 50% RPS from the first year onward, plus additional amounts of non-RPS compliant large hydro power to reduce GHG emissions;

3. **Ultra-Low GHG:** The CCA's supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by the fifth year.

To evaluate these scenarios, we assumed a simple portfolio consisting of RPS-eligible resources in an amount dictated by the particular scenario, with the balance of supply provided by non-renewable wholesale market purchases. In each case, we assumed that the RPS portfolio was predominately supplied with solar and wind resources, which are currently the low-cost sources of renewable energy. We assumed that solar and wind each contribute 45% of the renewable energy supply on an annual basis. To provide resource diversity and partly address the need for supply at times when solar and wind production are low, we assumed the remaining 10% of renewable supply would be provided by higher-cost baseload resources, such as geothermal or biomass.

As mentioned above, the CCA may choose to source a portion of its supply from local resources. Alameda County has significant potential for both wind and solar production. The wind resource is located in the Altamont Pass and largely consists of repowering existing turbines with a smaller number of much larger turbines. Costs are generally competitive with other California wind areas, however, the ability to develop projects is constrained by environmental impacts, primarily avian mortality in the Altamont Pass. A Programmatic Environmental Impact Report (PEIR) for the Alameda County portion of the Altamont Pass repowering would allow development of up to 450 MW. Since this amount of capacity may be developed regardless of whether the CCA is formed, and CCA local procurement wouldn't necessarily increase the amount of wind developed in the Altamont Pass, we have made the conservative assumption that the wind portfolio would effectively be from projects located outside of Alameda County. Thus, for the purpose of this study, we assumed that all of the local procurement by the CCA would be from solar energy, including a mix of smaller and larger projects.[22]

Figure 7 through Figure 9 show the assumed build-out of new resources under each of the three scenarios outlined above.

[22] Note that customer-owned generation, such as rooftop photovoltaic panels, is reflected in the load forecast rather than considered part of the supply portfolio. (I.e., the load forecast is what the CCA must serve, not the gross consumption at the home prior to factoring in customer-side PV.)

**Figure 7. Senario 1 CCA Build-Out**

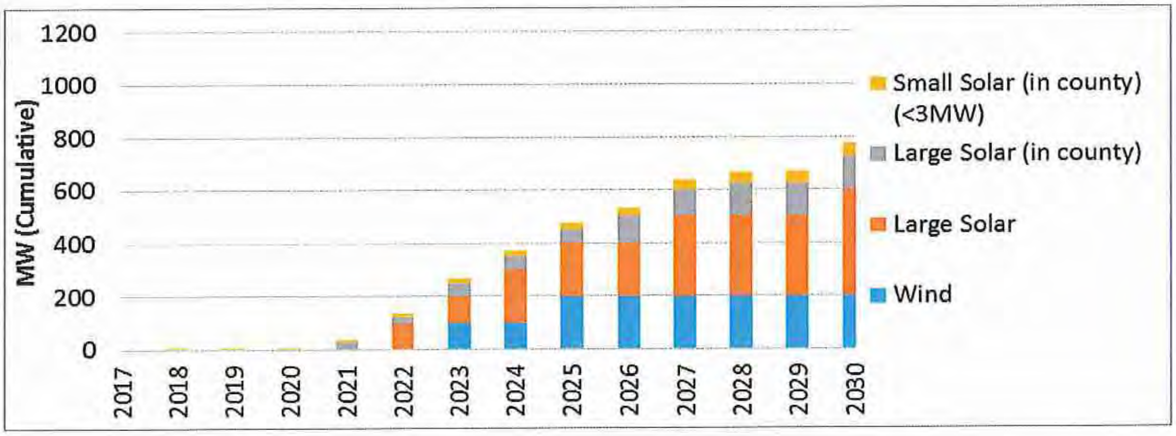



**Figure 8. Scenario 2 CCA Build-Out**

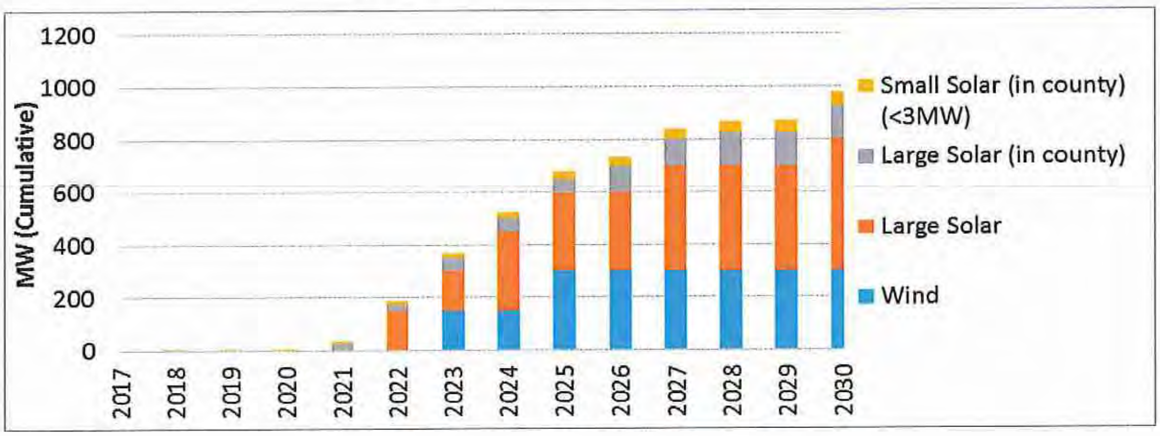
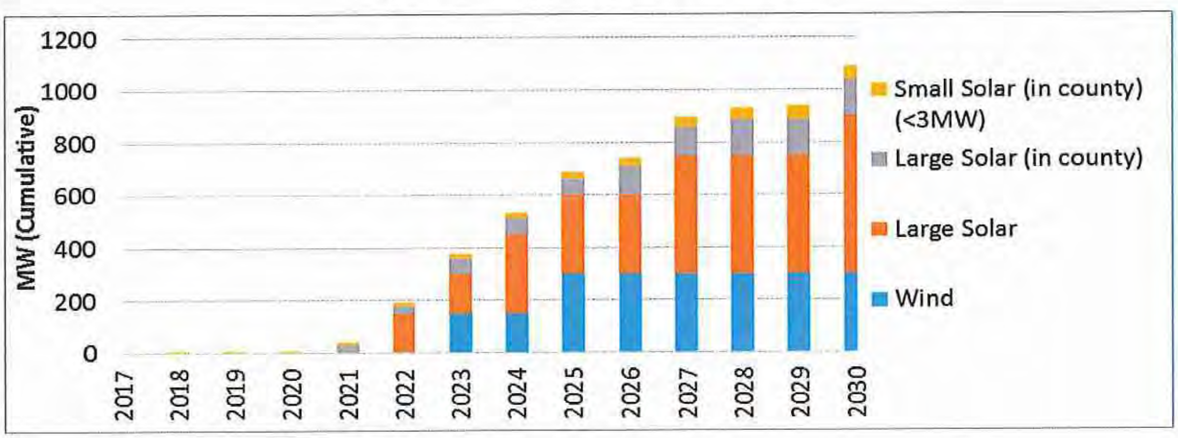


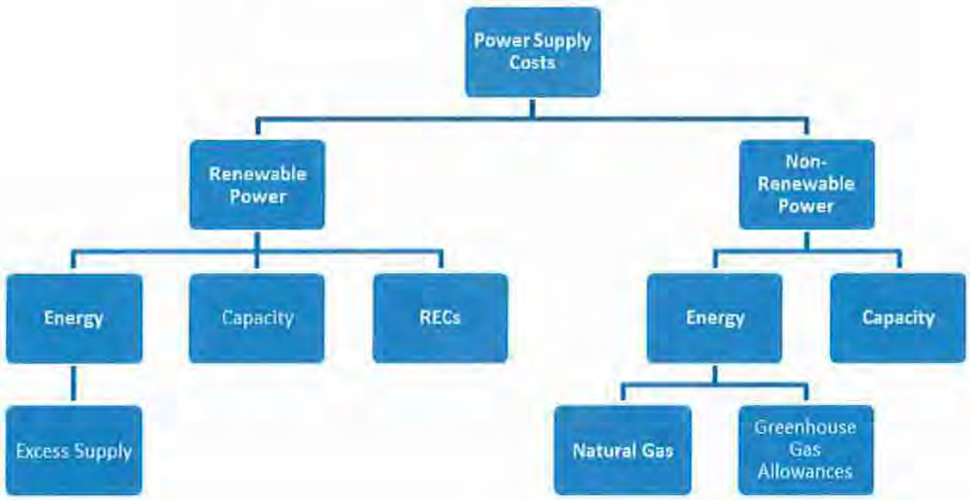

**Figure 9. Scenario 3 CCA Build-Out**



### Power Supply Cost Assumptions

As discussed above, the CCA would procure a portfolio of resources to meet its customers' needs, which would consist of a mix of renewable and non-renewable (i.e., wholesale market) resources. As shown in Figure 10, the products to be purchased by the CCA consist generally of energy, capacity and renewable attributes (which for counting purposes take the form of renewable energy credits, or RECs).[23]

**Figure 10. Power Supply Cost Elements**



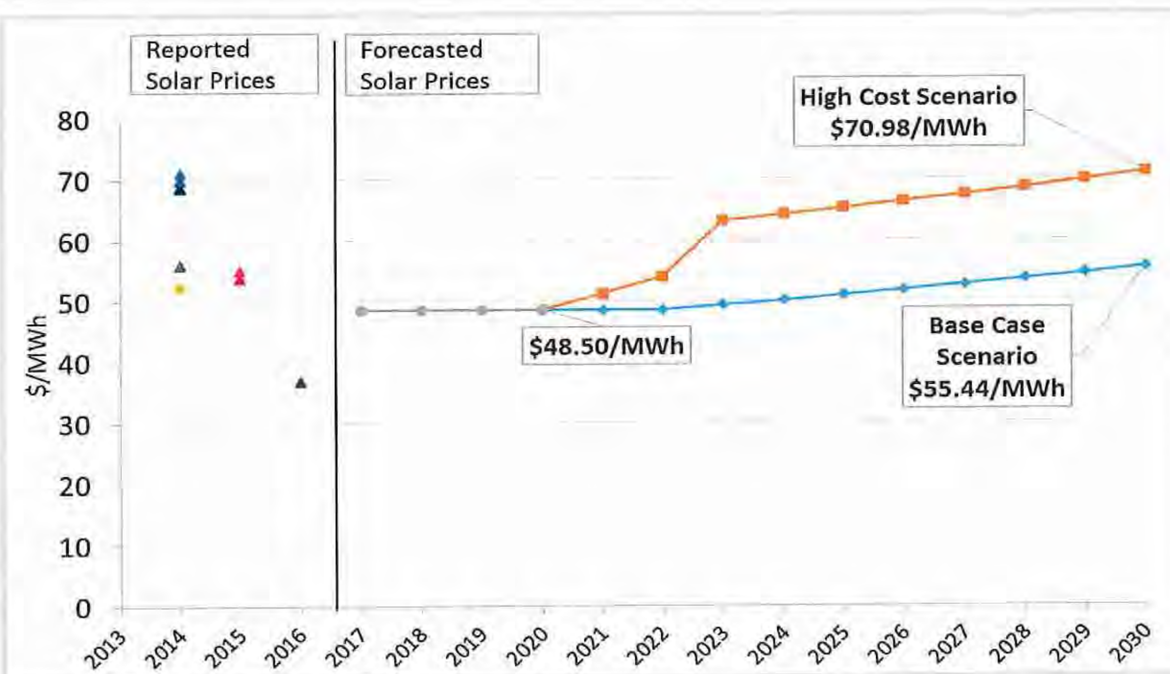

The CCA will be procuring supplies from the same competitive market for resources as PG&E. As a result, we assume that the costs for renewable and non-renewable energy and for resource adequacy capacity are the same for the CCA as for new purchases made by PG&E (as used in our forecast of PG&E rates discussed below). Wholesale market prices for electricity in California are largely driven by the cost of operating natural gas fueled power plants, since these plants typically have the highest operating costs and are the marginal units. As a result, market prices are a function of the efficiency of the marginal generators, the price of natural gas and the cost of GHG allowances. MRW developed forecasts of these elements to derive a power price forecast for use in determining costs for the CCA and PG&E. Capacity prices are based on prices for resource adequacy contracts reported by the CPUC.

MRW developed a forecast of renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and CCAs in 2015 and early 2016, finding an average price of $49/MWh for the solar contracts, $55/MWh for wind power

[23] RECs are typically bundled with energy deliveries from renewable energy projects, with each REC representing 1 MWh of renewable energy. A limited number of unbundled RECs may be used to meet RPS requirements. For the purpose of this study we have not considered unbundled RECs and have rather estimated costs based on renewable energy contracts where the RECs are bundled.

and $80/MWh for geothermal.[24] We used these prices as the starting point for our forecast of CCA renewable energy procurement costs. For geothermal, which is a relatively mature technology, we assumed that new contract prices would simply escalate with inflation. Solar and wind prices are a function of technology costs, which have generally been declining over time; financing costs, which have been very low in recent years; and tax incentives, which significantly reduce project costs, but phase out over time. In the near-term we would not expect prices to increase as technology costs and continued tax incentives provide downward pressure and likely offset any increase in financing costs or other competitive pressure from an increasing demand for renewable energy in California. Thus we have held solar and wind prices constant in nominal dollars through 2020. Beyond 2020, with increasing competitive pressure associated with the drive to a 50% RPS and the anticipated phase-out of federal tax incentives (offset in part by continued declining technology costs), we would expect prices to increase somewhat and have assumed they escalate at the rate of inflation. In addition to this base case price outlook, we also consider a high solar cost scenario based on work performed by Lawrence Berkeley Laboratory on the value of tax incentives. In the high scenario we assume that costs increase with the phase-out of federal tax incentives, without being offset by declining technology costs. Figure 11 shows the resulting solar price forecasts for the two scenarios.

**Figure 11. Solar Price Forecast**




[24] MRW relied exclusively on prices from municipal utilities and CCAs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in *California Energy Markets*, an independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

### Locally-Sited and Developed Renewables

As discussed above, the CCA may choose to contract with or develop renewable projects in the local area to promote economic development or other benefits. For the purpose of this study, we assume that incremental local development resulting from the CCA would be largely solar. Since the solar resource in Alameda County is not as strong as in the desert and inland areas where new utility-scale projects are typically developed (and upon which the above solar price forecast was developed), solar generation costs in Alameda County are expected to be somewhat higher than our price forecast. Based on renewable energy supply curves developed for the CPUC, we assume a 15% premium for projects located in Alameda County.[25]

Given the limited open space for very large solar projects in the County, we expect a portion of the local projects included in a hypothetical CCA portfolio to be smaller in size (e.g., < 3 MW). Smaller solar projects tend to have higher generation costs since they don't have the same economies of scale as the larger projects upon which our estimates of market prices are based. We have assumed a 55% generation cost premium for smaller projects, based on the same supply curve study referenced above. Future price changes and economies of scale might lower this value.

In developing the hypothetical portfolios depicted in Figure 7 through Figure 9, we made conservative assumptions about how much local solar development may occur as a result of the CCA. The supply curve study performed for the CPUC estimated roughly 300 MW of solar supply in Alameda County, based on an assessment that five percent of the estimated 6,000 MW of technical potential could be developed, largely as a result of land use conflicts or slope issues that would make solar development infeasible in certain areas. We assume that over the forecast period through 2030, about 1/3 of the estimated 300 MW large solar supply potential in Alameda County is developed as a result of commitments by the CCA.

A discussion of the impacts and implications of greater local renewables can be found in Chapter 7.

### Greenhouse Gas Costs

MRW based its forecast of the prices for GHG allowances on the results of the California Air Resources Board's (ARB's) auctions for Vintage 2015 allowances.[26] The Vintage 2015 Allowances were increased annually in proportion to the auction floor price increases stipulated by the ARB's cap-and-trade regulation.[27]

**Table 3 GHG Allowances price**

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $/tonne | 14.0 | 15.0 | 16.0 | 17.2 | 18.4 | 19.6 | 21.0 | 22.4 | 24.0 | 25.6 | 27.4 | 29.3 | 31.3 | 33.5 |

[25] CPUC RPS calculator (RETI 2.0)

[26] Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

[27] California Code of Regulations, Title 17, Article 5, Section 95911.

Total GHG costs were calculated by multiplying the allowance price by the amount of carbon emitted per megawatt-hour for each assumed resource. For "system" purchases, MRW assumed that the GHG emissions corresponded to a natural gas generator operating at the market heat rate. This worked out to be, on average, approximately $5 per megawatt delivered.

### Other CCA Supply Costs

The CCA is expected to incur additional costs associated with its procurement function. For example, if the CCA relies on a third-party energy marketing company to manage its portfolio it will likely incur broker fees or other expenses equal to roughly 5% of the forecasted contract costs. The CCA would also incur costs charged by the California Independent System Operator (CAISO) for ancillary services (activities required to ensure reliability) and other expenses. MRW added 5.5% to the CCA's power supply cost to cover these CAISO costs. Finally, we added an expense associated with managing the CCA's renewable supply portfolio. Based on an analysis of the expected CCA load shape and the typical generation profile of California solar and wind resources, we observed that there will be hours in which the expected deliveries from renewable contracts will be greater than the CCAs load in that hour. This results from the amount of renewable capacity that must be contracted to meet annual RPS targets and the variability in renewable generation that leads to higher deliveries in some hours and lower deliveries in other hours. When high renewable energy deliveries coincide with low loads, the CCA will need to sell the excess, likely at a loss, or curtail deliveries, and potentially have to make up those renewable energy purchases during higher load hours to comply with the RPS. The result is that the procurement costs will be somewhat higher than simply contracting with sufficient capacity to meet the annual RPS.

## PG&E Rate and Exit Fee Forecasts

MRW developed a forecast of PG&E's bundled generation rates and CCA exit fees in order to compare the projected rates that customers would pay as Alameda County CCA customers to the projected rates and fees they would pay as bundled PG&E customers.

### PG&E Bundled Generation Rates

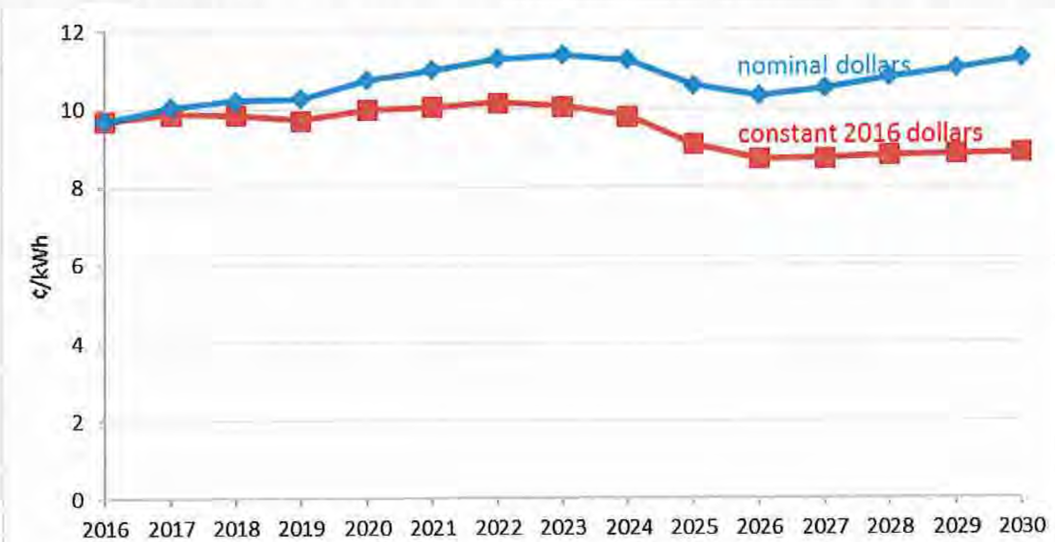
To ensure a consistent and reliable financial analysis, MRW developed a 30-year forecast of PG&E's bundled generation rates using market prices for renewable energy purchases, market power purchases, greenhouse gas allowances, and capacity that are consistent with those used in the forecast of Alameda County CCA's supply costs. MRW additionally forecast the cost of PG&E's existing resource portfolio, adding in market purchases only when necessary to meet projected demand. MRW assumed that near-term changes to PG&E's generation portfolio would be driven primarily by increases to the Renewable Portfolio Standard requirement in the years leading up to 2030 and by the retirement of the Diablo Canyon nuclear units at the end of their current license periods in 2024 and 2025. More information about this forecast is provided in Appendix B.

MRW forecasts that, on average, PG&E's generation rates will increase just slightly faster than inflation through 2030, with 2030 rates 3% higher than today's rates when considered on a constant dollar basis (i.e., assuming zero inflation). Underlying this result are three distinct rate periods:

1. An initial period of faster rate growth through 2023 (1.3% above inflation);
2. A period of rate decline from 2023-2026 (2.5% below inflation) primarily due to the retirement of Diablo Canyon[28]; and
3. A period of dampened rate growth through 2030 (0.2% above inflation) primarily due to the replacement of high-cost renewable power contracts currently in PG&E's portfolio with new lower-priced contracts (reflecting the significant fall in renewable power prices in recent years).

PG&E's bundled generation rates in each year of MRW's forecast are shown in Figure 12, on both a nominal and constant-dollar basis.

**Figure 12: PG&E Bundled Generation Rates, nominal and constant-dollar forecasts**




### PG&E Exit Fee Forecast

In addition to the bundled rate forecast, MRW developed a forecast of the Power Charge Indifference Adjustment ("PCIA"), which is a PG&E exit fee that is charged to CCA customers. The PCIA is intended to pay for the above-market costs of PG&E generation resources that were acquired, or which PG&E committed to acquire, prior to the customer's departure to CCA. The total cost of these resources is compared to a market-based price benchmark to calculate the "stranded costs" associated with these resources, and CCA customers are charged what is determined to be their fair share of the stranded costs through the PCIA.

MRW forecasted the PCIA charge by modeling expected changes to PCIA-eligible resources and to the market-based price benchmark through 2030, using assumptions consistent with those used in the PG&E rate model. Based on our modelling, we expect the PCIA to increase by 8% over the 2016-2018 period (4% in constant dollars) and subsequently to decline in most years

[28] More information can be found in the Appendix C

until it drops off completely in the late 2030s. MRW's forecast of the residential PCIA charge through 2030 is summarized in Table 4.

**Table 4. PG&E Residential PCIA Charges, ¢/kWh (nominal)**

| 2015 | 2018 | 2020 | 2025 | 2030 |
|---|---|---|---|---|
| 2.3 | 2.5 | 2.2 | 1.1 | 0.9 |

## Pro Forma Elements and CCA Costs of Service

MRW conducted a pro forma analysis to evaluate the expected financial performance of the CCA and the CCA's competitive position *vis a vis* PG&E. The analysis was conducted on a forward looking basis from the expected start of CCA operations in 2017 through the year 2030, with several scenarios considered to address uncertainty in future circumstances.

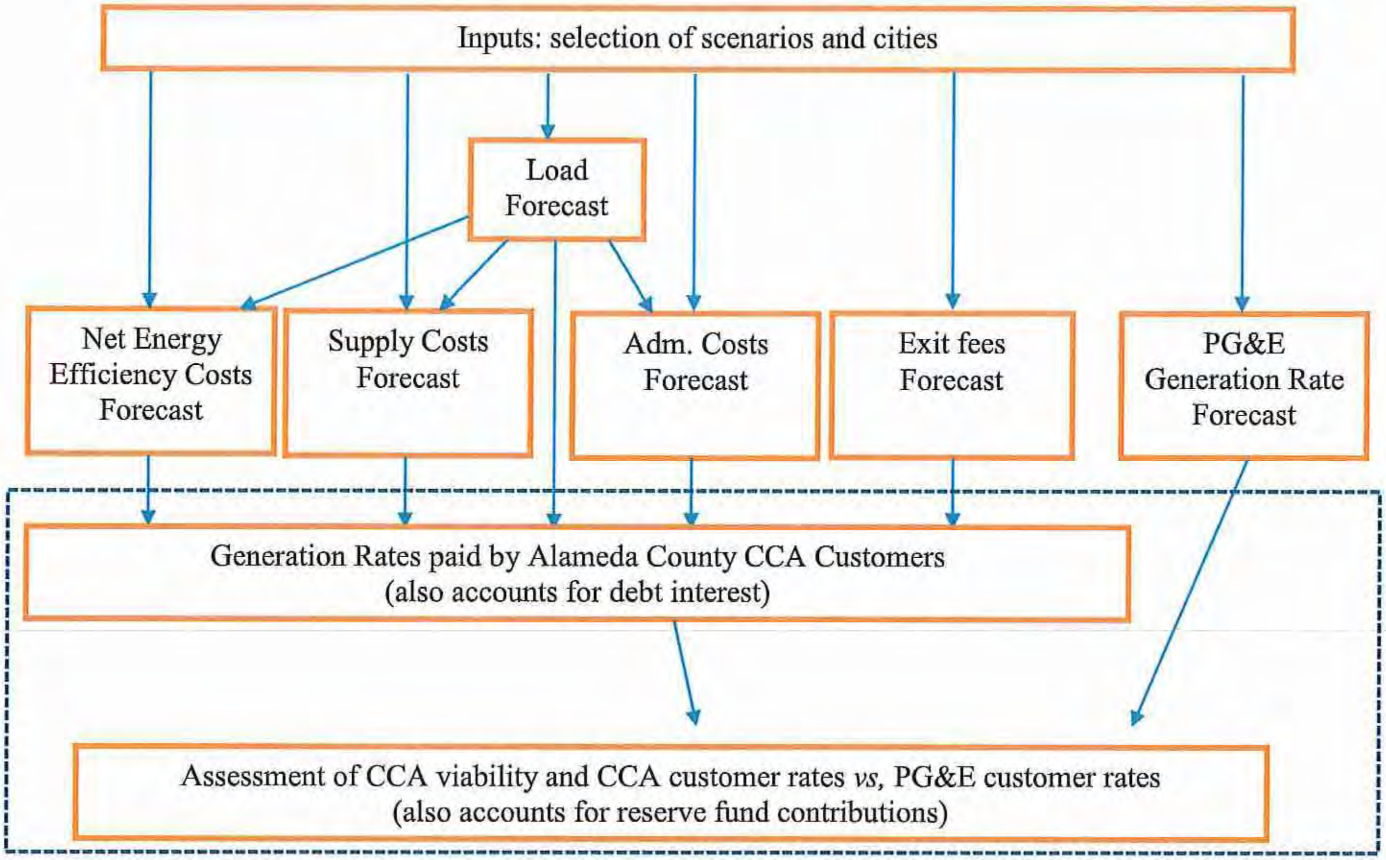
### Pro Forma Elements

Figure 13 provides a schematic of the pro forma analysis, outlining the input elements of the analysis and the output results. The analysis involves a comparison between the generation-related costs that would be paid by Alameda County CCA customers and the generation-related costs that would be paid by PG&E bundled service customers. Costs paid by CCA customers include all CCA-related costs (*i.e.*, supply portfolio costs, net energy efficiency costs,[29] and administrative and general costs) and exit fee payments that CCA customers will be required to make to PG&E.

As discussed in previous sections, supply portfolio costs and energy efficiency program costs are informed and affected by CCA loads, by the requirements the CCA will need to meet (or will choose to meet) such as with respect to renewable procurement, and by CCA participation levels, which can vary depending on whether or not all cities in the county choose to join the CCA. Administrative and general costs are discussed further below.

[29] We anticipate that Alameda County CCA's energy efficiency costs will be fully offset by Public Benefits Charge revenue provided by PG&E for the purpose of energy efficiency programming and that net costs to Alameda County CCA will be zero.

**Figure 13. Pro forma Analysis**



**Startup Costs**

Table 5 shows the estimated CCA startup costs. They are based on the experience of the existing CCAs as well as from other CCA feasibility assessments.

**Table 5. Estimated Start-Up Costs**

| Item | Cost |
|---|---|
| Technical Study | $200,000 |
| JPA Formation/Development | $100,000 |
| Implementation Plan Development | $50,000 |
| Power Supplier Solicitation & Contracting | $75,000 |
| Staffing | $1,000,000 |
| Consultants and Legal Counsel | $500,000 |
| Marketing & Communications | $500,000 |
| PG&E Service Fees | $75,000 |
| CCA Bond | $100,000 |
| Miscellaneous | $500,000 |
| **Total** | **$ 3,300,000** |
| Working Capital | $51,000,000 |
| **Total** | **$54,300.000** |

Working capital is set to equal three months of CCA revenue, or approximately $50 million. This amount would cover the timing lag between when invoices for power purchases (and other account payables) must be remitted and when income is received from the customers. Initially, the working capital is provided by a bank on credit to the CCA. Typical power purchase contracts require payment for the prior month's purchases by the 20th of the current month. Customers' payments are typically received 60 to 90 days from when the power is delivered.

These startup costs are assumed to be financed over 5 years at 5% interest.

**Energy Efficiency Program Costs**

CCA's have the opportunity use both electric and gas public purpose program funds to provide energy efficiency programs to customers, and using rules defined in CPUC Ruling R.09-11-014 and various cost reports.[30]As discussed in Chapter 7, approximately $3.9 million would be available for programs administered by a CCA to Alameda County residents, including both

[30] Electric and Gas Utility Cost Report. Public Utilities Code Section 913 Report to the Governor and Legislature, April 2016.

CCA and PG&E customers, or $3.5 million if these programs serve only CCA customers, assuming a 15% opt-out rate. This latter case was modeled.

### Administrative and General Cost Inputs

Administrative and general costs cover the everyday operations of the CCA, including costs for billing, data management, customer service, employee salaries, contractor payments, and fees paid to PG&E. MRW conducted a survey of the financial reports of existing CCAs to develop estimates of the costs that would be faced by an Alameda County CCA. Administrative and general costs are phased in from 2017 to 2019, as the CCA operations expand to cover the entire territory of the county; after that, costs are escalated by 2% each year to account for the effects of inflation.

Administrative and general costs are unchanged under the three renewable level scenarios, but do vary based on how many cities join the CCA and the number of participating customer accounts. As previously mentioned, a 15% opt-out rate has been assumed for customer participation.

### Cost of Service Analysis and Reserve Fund

To determine annual CCA costs and the rates that would need to be charged to CCA customers to cover these costs, MRW summed the three categories of CCA costs (*i.e.*, supply portfolio costs, net energy efficiency costs, and administrative and general costs) and added in debt financing to cover start-up costs and initial working capital. Financing was assumed to be for a five-year period at an interest rate of 5%. These costs were divided by projected CCA loads to develop the average rate the CCA would need to charge customers to cover its costs ("minimum CCA rate").

To establish the Alameda County CCA rate, MRW adjusted the minimum CCA rate, if needed, based on the competitive position of the CCA. In particular, when the total CCA customer rate (*i.e.,* the minimum CCA rate plus the PG&E exit fee) was below the projected PG&E generation rate,[31] MRW increased the minimum CCA rate up to the amount needed to meet the reserve refund targets while still maintaining a discount. MRW used the surplus CCA revenue from these rate increases ("Reserve Fund") in order to maintain Alameda County CCA competitiveness with PG&E rates in years in which total CCA customer rates would otherwise be higher than PG&E generation rates.[32]

[31] For this analysis, MRW used the average of the projected PG&E generation rates across all rate classes, weighted by the projected Alameda County CCA load in each rate class.
[32] MRW applied a Reserve Fund cap of 15% of the annual operating cost. After this cap was reached, no further rate increases were applied for the purpose of Reserve Fund contributions.

# Chapter 3: Cost and Benefit Analysis

As described in the prior chapter, as part of the pro forma analysis, MRW calculated Alameda County CCA rates that would, where feasible, cover CCA costs and maintain long-term competitiveness with PG&E. This chapter uses those rates to compare the costs and benefits of the Alameda County CCA across three scenarios: (1) Renewable Compliance, (2) Accelerated RPS and (3) 80% RPS by 2021. Costs and benefits are evaluated by comparing total CCA customer rates (including PG&E exit fees) to PG&E generation rates to assess the net bill savings (costs) for customers that join the CCA.

## Scenario 1 (Renewable Compliance)

Under Scenario 1, the Alameda County CCA meets all RPS requirements (including Senate Bill 350 requirements) and does not obtain incremental renewable power or low-carbon power in excess of these requirements.

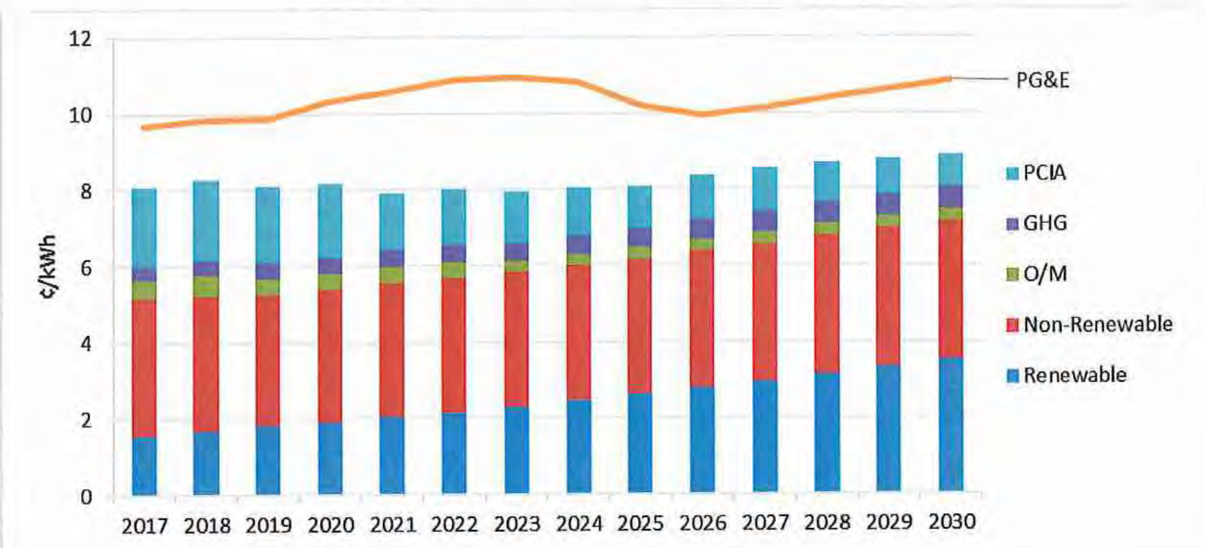
### Rate Differentials

Figure 14 summarizes the results of this scenario in the form of the total Alameda County CCA customer rate (vertical bars) and the comparable PG&E generation rate (line).[33] Of the CCA cost elements, the greatest cost is for non-renewable generation followed by the cost for the renewable generation, which increases over the years according to the RPS standards. Another important CCA customer cost is the PCIA exit fee, which is expected to decrease in most years beginning in 2019 and to become less important over time.

Under Scenario 1, the differential between PG&E generation rates and Alameda County CCA customer rates is positive in each year (*i.e.*, CCA rates are lower than PG&E rates). As a result, Alameda County CCA customers' average generation rate (including contributions to the reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year. The annual differential between the PG&E rate and the total CCA customer rate is expected to vary significantly over the course of this period (Figure 14). During the initial period from 2017-2023, the differential between the two rates increases (*i.e.*, the CCA becomes more cost-competitive) due to an expected decrease in the exit fees charged to Alameda County CCA customers. Beginning in 2024, the rate differential narrows due to a decrease in PG&E generation rates stemming from the closure of the Diablo Canyon nuclear plant. After 2026, the difference between the two rates is expected to increase at a modest rate as PG&E's generation rates stabilize and exit fees decline.

[33] All rates are in nominal dollars

**Figure 14. Scenario 1 Rate Savings, 2017-2030**




## Residential Bill Impacts

Table 6 shows the average annual savings for Residential customers under Scenario 1. The average annual bill for the residential customer on the Alameda County CCA program will be on average 7% lower than the same bill on PG&E rates.

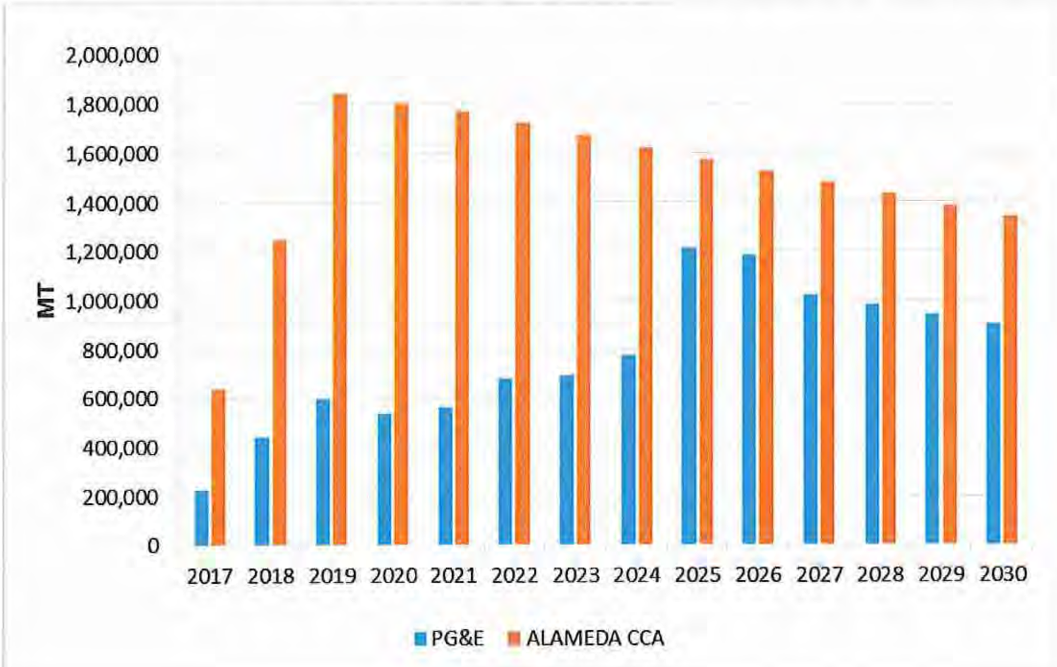
**Table 6. Scenario 1 Savings for Residential CCA Customers**

| Residential | Monthly Consumption (kWh) | Bill with PG&E ($) | Bill with Alameda County CCA ($) | Savings ($) | Savings (%) |
|---|---|---|---|---|---|
| 2017 | 650 | 147 | 142 | 5 | 3% |
| 2020 | 650 | 160 | 145 | 15 | 9% |
| 2030 | 650 | 201 | 188 | 13 | 6% |

## Greenhouse Gas Emissions

Figure 15 shows the GHG emissions from 2017-2030 for Alameda County CCA under Scenario 1, and PG&E's expected emissions for the same load if no CCA is formed. The CCA's GHG emissions initially increase from 2017 to 2019 as the CCA is phased in across the county (from serving 33% potential county load in 2017 to 100% in 2019), and then decrease steadily in the following years as the CCA's renewable content grows pursuant to SB 350's requirements of 50% RPS by 2030. PG&E emissions are lower than those of the CCA in this scenario due to the diversity in PG&E's electric mix. Besides renewable generation, over 40% of PG&E's supply portfolio is made up of nuclear and large hydro generation, both of which are emissions-free generation technologies. PG&E's GHG emissions decrease before 2019 and increase between 2019 and 2024 due to the changes in its RPS procurement.34 In 2025, the retirement of the Diablo Canyon nuclear generation plant increases PG&E's GHG emissions by approximately 30% as the utility will need to increase its fuel-fired generation to make up for the loss. In the following years PG&E's GHG emissions are expected to decrease as it ramps up renewable procurement to meet its mandated RPS goals.

**Figure 16. Scenario 1 GHG Emissions by Year ("Normal" PG&E Hydro Conditions)**




## Scenario 2 (Accelerated RPS)

Under Scenario 2, Alameda County CCA meets 50% of its load through renewable power starting from 2017, while 50% of its non-renewable load is met through hydro-electricity.

### Rate Differentials

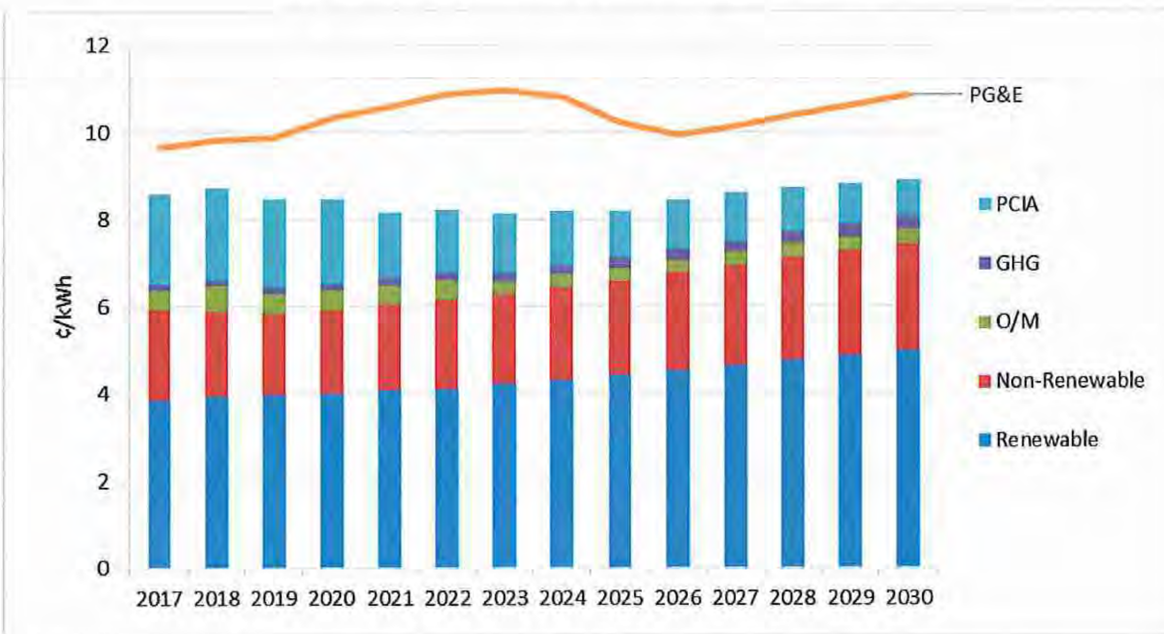
Figure 17 summarizes the results for this scenario, with the vertical bars representing the Alameda County CCA customer rate and the counterpart PG&E generation rate shown as a line.

[34] According to the PG&E RPS plan PG&E Final 2015 Renewable Energy Procurement Plan, filed in CPUC proceeding R.15-02-020, January 14, 2016, Appendix D, Table 2 and Table 4, the RPS procurement in 2019-2024 falls in average 3.5% annual.

In this scenario, the renewable lost is the largest single element of the CCA rate, reflecting the higher renewable content of this scenario. Non-renewable generation is the next largest cost component of the rate, followed by the PCIA exit fee. The PCIA exit fee is expected to decrease in most years beginning in 2019, as it did in the case of Scenario 1. However, the costs associated with GHG allowance purchases are a lower portion of the total costs in this scenario because 50% of the non-renewable generation is expected to be met by hydro-electricity, which is a non-emitting resource. This limits the need for purchase of GHG allowances.

The differential between PG&E generation rates and Alameda County CCA customer rates in Scenario 2 is lower than that under Scenario 1; however, it continues to follow a similar pattern over the years with respect to PG&E rates, and it is positive in all years from 2017 to 2030. As was the case under Scenario 1, because of this positive differential, Alameda County CCA customers' average generation rate (including contributions to the reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year under this scenario as well.

**Figure 17. Scenario 2 Rate Savings, 2017-2030**




## Residential Bill Impacts

Table 7 below shows the average annual savings for residential customers under Scenario 2. The annual bill for a residential customer on the Alameda County CCA program will be for the period 2017-2030 on average 6.5% lower than the same bill on PG&E rates. This is lower than, but close to, bill savings under Scenario 1.

**Table 7. Scenario 2 Savings for Residential CCA Customers**

| Residential | Monthly Consumption (kWh) | Bill with PG&E ($) | Bill with Alameda County CCA ($) | Savings ($) | Savings (%) |
|---|---|---|---|---|---|
| 2017 | 650 | 147 | 146 | 1 | 1% |
| 2020 | 650 | 160 | 147 | 13 | 8% |
| 2030 | 650 | 201 | 188 | 13 | 6% |

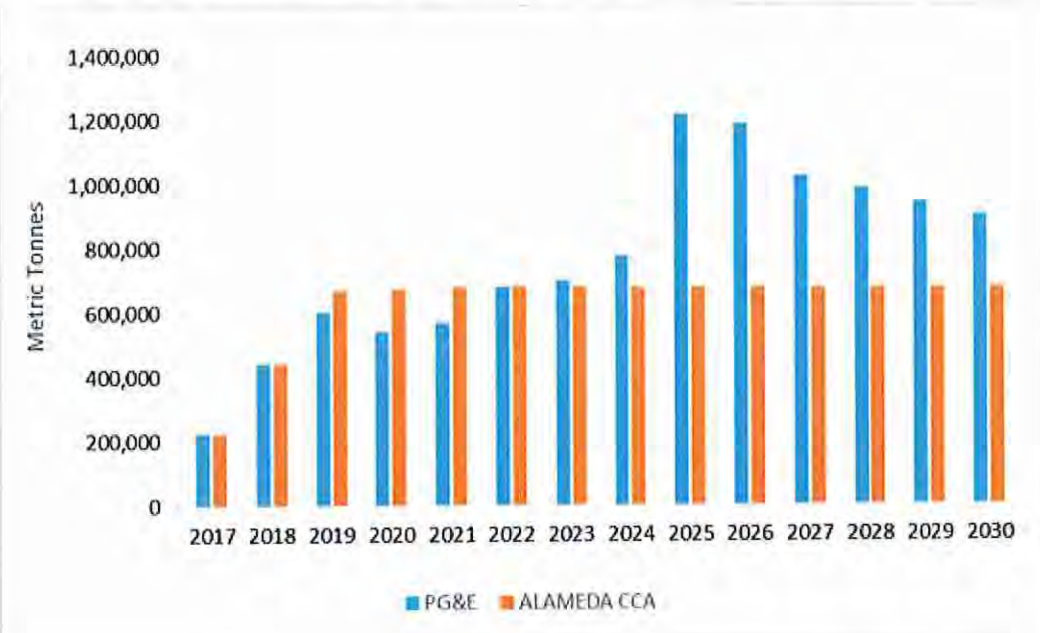
## GHG Emissions

The Alameda County CCA's GHG emissions under Scenario 2 are much lower than those under Scenario 1. This is due to the higher renewable content in the CCA's generation mix under Scenario, as well as the 50% hydro content in the non-renewable generation mix.

Figure 18 compares the GHG emissions from 2017-2030 for the Alameda County CCA under Scenario 2 with what PG&E's emissions would be for the same load if no CCA is formed. The Alameda County CCA's emissions increase from 2017 to 2019 as the CCA is phased in across the entire county, and then remain flat through 2030. PG&E's GHG emissions are initially slightly lower than the CCA's emissions, but as the CCA's emissions flatten out, PG&E's emissions follow a generally upward trend and surpass CCA emissions in 2024, with the expected retirement of Diablo Canyon in 2025 – further bumping up PG&E's emissions by approximately 30% in 2025. Following this, PG&E's emissions are expected to decrease from 2026 to 2030 as PG&E procures renewables to meet its mandated RPS goals. However, they still remain higher than the CCA's expected GHG emissions.

Note that the analysis assumes "normal" hydroelectric output for PG&E. during the drought years, PG&E's hydro output has been at about 50% of normal, and the utility has made up these lost megawatt-hours through additional gas generation. This means that our PG&E emissions are the PG&E emissions shown here are lower that the "current" emission. If, as is expected by many experts, the recent drought conditions are closer to the "new normal, then PG&E's GHG emissions in the first 8 years would be approximately 30% higher, resulting in GHG savings for Scenario 2 rather than parity.

**Figure 18. Scenario 2 GHG Emissions by Year ("Normal" PG&E Hydro Conditions)**




## Scenario 3 (80% RPS by 2021)

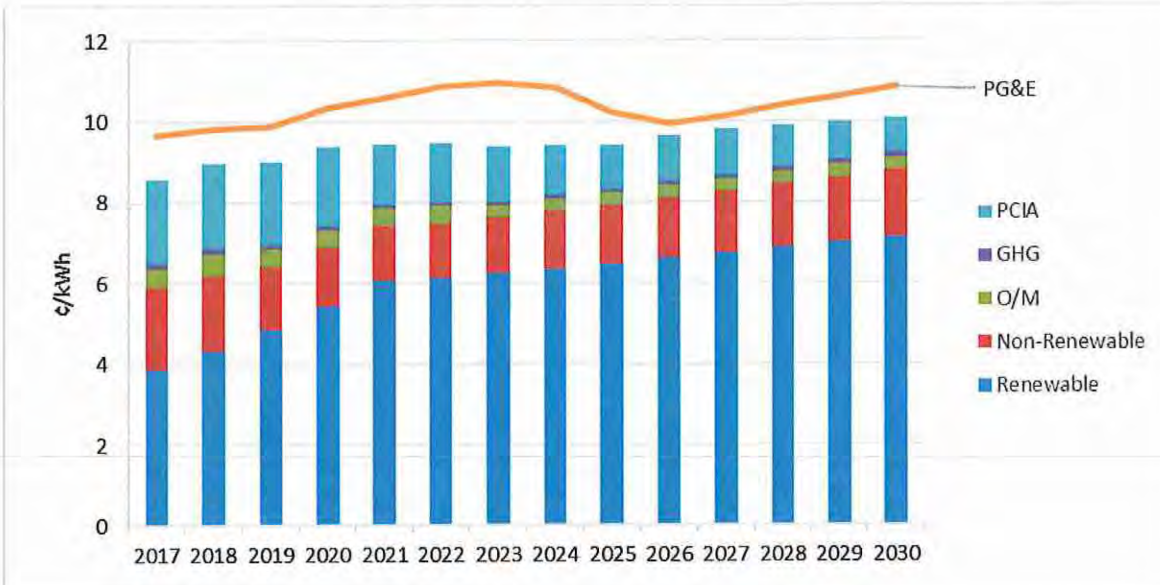
Scenario 3 is the most aggressive scenario considered, in terms of renewable procurement. Under this scenario, the Alameda County CCA starts with 50% of its load being served by renewable sources in 2017, and increases this at a quick pace to 80% of its load being served by renewable sources in 2021. In addition, 50% of its non-renewable supply is met through large hydro-electric sources.

### Rate Differentials

Figure 19 summarizes the rates for the Alameda County CCA under Scenario 3 from 2017 to 2030, and also shows PG&E's expected generation rate for comparison. Under this scenario, the costs for renewables form the largest component of the CCA's rates, and grows steadily to account for nearly 60% of the total CCA rate in 2019, and then nearly 70% of total CCA rate by 2030. Non-renewable generation is the next largest cost component of the rate, followed by the PCIA exit fee. The PCIA exit fee is expected to decrease in most years beginning in 2019, as it did in the case of Scenarios 1 and 2. As with Scenario 2, the costs associated with GHG allowance purchases are a lower portion of the total costs in this scenario because 50% of the non-renewable generation is expected to be met by hydro-electricity, which is a non-emitting resource. However, as the renewable content increases and the non-renewable content decreases, the need for purchase of GHG allowances is further lowered, making the GHG costs an even smaller component of the total rate.

The differential between PG&E generation rates and Alameda County CCA customer rates in Scenario 3 is the lowest of the three scenarios, as this scenario has the most expensive supply portfolio. However, the expected Alameda County CCA rates continue to be lower than expected PG&E generation rates for all years from 2017 to 2030. Though this positive differential still allows for the collection of reserve fund contributions through the CCA's rates in all the years under consideration, between 2026 to 2028 the differential is very small.

**Figure 19. Scenario 3 Rate Savings, 2017-2030**




## Residential Bill Impacts

Table 8 below shows the average impacts on the bills of residential customers under Scenario 3. The annual bill for a residential customer on the Alameda County CCA program will be on average 3% lower (over the 2017-2030 study period) than the same customers on PG&E rates, under this scenario.

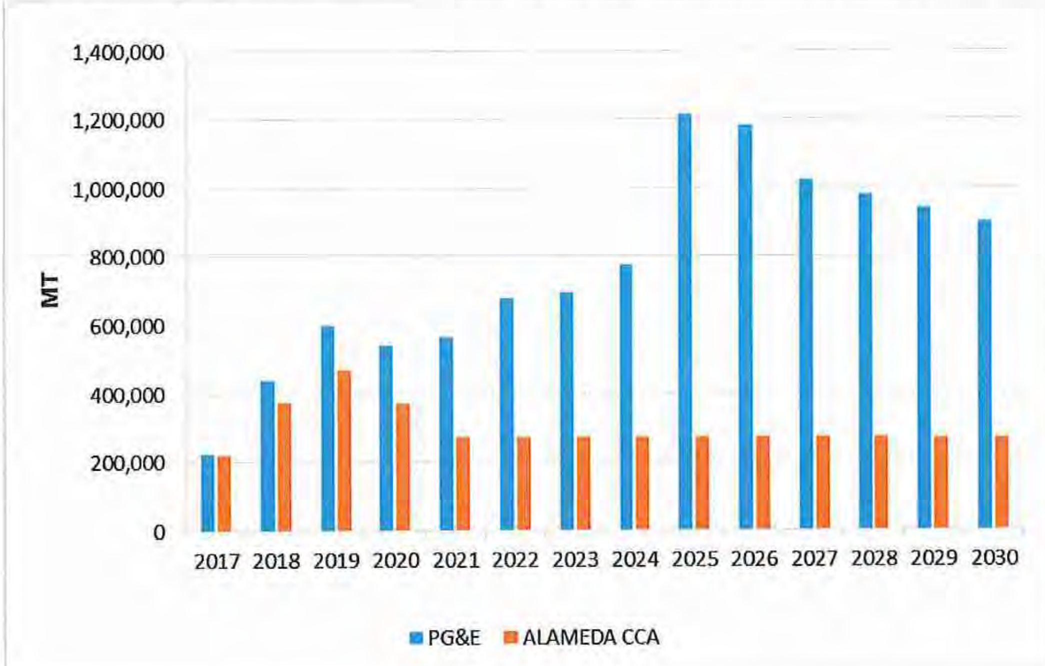
**Table 8. Scenario 3 Savings for Residential CCA Customers**

| Residential | Monthly Consumption (kWh) | Bill with PG&E ($) | Bill with Alameda County CCA ($) | Savings ($) | Savings (%) |
|---|---|---|---|---|---|
| 2017 | 650 | 147 | 146 | 1 | 1% |
| 2020 | 650 | 160 | 154 | 6 | 4% |
| 2030 | 650 | 201 | 196 | 5 | 2% |

## GHG Emissions

Similar to Scenarios 1 and 2, under Scenario 3, the Alameda County CCA's GHG emissions first increase from 2017 to 2019 as the CCA is phased in into the entire county. However, in Scenario 3 this increase is partially off-set by the increasing renewable content in the CCA's supply mix. Thus the CCA's emissions in this scenario grow at a slower rate from 2017 to 2019 than in the first 2 scenarios, then decrease till 80% renewable supply is achieved in 2021, and remain flat thereafter. The CCA's GHG emissions under this scenario are lower than PG&E's expected emissions for the same load if no CCA is formed. Figure 20 shows the expected GHG emissions from the CCA and PG&E for all years from 2017 to 2030.

**Figure 20. Scenario 3 GHG Emissions by Year ("Normal" PG&E Hydro Conditions)**



# Chapter 4: Sensitivity of Results to Key Inputs

In addition to the base case forecast described above, MRW has assessed alternative cases to evaluate the sensitivity of the results to possible conditions that would have an impact on Alameda County CCA's feasibility study. The metric considered to compare the alternative sensitivity cases to the base case is the differential between the annual average generation rates for PG&E bundled customers and for Alameda County CCA customers.[35]

The base-case analysis (Chapter 3 –Scenario 1) was developed as a reasonable and conservative assessment of the Alameda County CCA. In addition to the base case analysis, MRW analyzed alternative cases to address six risks: (1) the relicensing of the Diablo Canyon nuclear units, (2) higher renewable supply costs, (3) higher PCIA charges, (4) higher natural gas prices, (5) lower PG&E portfolio costs, and (6) a combination of the last four of these five risks (stress scenario).

## Diablo Canyon Relicensing Sensitivity

In the base case the Diablo Canyon nuclear units are retired at the end of their current operating licenses (Unit 1 in 2024 and Unit 2 in 2025).[36] At this time, nuclear retirement appears to be the lower-cost option for PG&E ratepayers given, on the one hand, low market prices for replacement power (both gas-fired and renewable) and, on the other hand, the significant costs PG&E would likely incur to undertake a cooling system modification and potentially other upgrades that would be required to relicense the plant and continue operations.[37] Under the relicensing scenario, PG&E's generation rate would therefore increase, providing a competitive benefit to the Alameda County CCA.[38] As shown in Table 8, MRW anticipates that the average rate differential over the 2017-2030 period would increase by 1.35¢/kWh under the Diablo Canyon relicensing scenario.

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[35] The Alameda County CCA rate includes the PG&E exit fees (PCIA charges) that will be charged to CCA customers but does not include the rate adjustment for the reserve fund.

[36] This assumption is consistent with the CPUC's proposed assumptions for long-term transmission planning. "Administrative Law Judge's Ruling Seeking Comment on Assumptions and Scenarios for use in the California Independent System Operator's 2016-17 Transmission Planning Process and Future Commission Proceedings," CPUC proceeding R.13-12-010, February 8, 2016, page 41.

[37] The new cooling system, which would be required per state regulations implementing the Federal Clean Water Act, Section 316(b), would have an estimated cost of $4.5 billion. Subcommittee Comments on Bechtel's Assessment of Alternatives to Once-Through-Cooling for Diablo Canyon Power Plant. November 18, 2014, page 10.

[38] An increase in PG&E's rates results in an increase to the CCA customers' exit fees (which pay for the above-market costs of PG&E's rates). However, this exit fee increase is much smaller than the PG&E rate increase, and the relicensing scenario provides an overall benefit to the CCA.

**Table 9. Diablo Canyon Relicensing Sensitivity Results, 2017-2030**

| | Average PG&E Rate (¢/kWh) | Average Rate Differential (¢/kWh) |
|---|---|---|
| **Base Case** | 10.36 | 2.1 |
| **Diablo Canyon Relicensing** | 11.75 | 3.4 |

## Higher Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher prices for renewable power on the CCA's financial viability. As discussed in Appendix B, in the base case, renewable power prices are flat in nominal dollars through 2022, based on the assumption that projected declines in renewable development costs will offset increases associated with the planned expiration of federal renewable tax credits.[39,40] In the Higher Renewable Power Prices sensitivity, we assume that renewable prices would be flat in nominal dollars through 2022 if it were not for the tax credit expirations and add the impact of the tax credit expirations to the base case prices. Average renewable power prices in this scenario are 0-10% higher than in the base case scenario through 2021, about 20% higher in 2021 and 2022, and 30% higher after 2022 when the solar investment tax credit is reduced to 10%. These higher prices affect both the CCA and PG&E, but they have a greater effect on the CCA because PG&E has significant amounts of renewable resources under long-term contract. The impact of this stress case is to reduce the 2017-2030 average rate differential by 0.3¢/kWh relative to the base case.

**Table 10. Higher Renewable Power Prices Sensitivity Results, 2017-2030**

| | Average Renewable Power Prices (¢/kWh)[41] | Average Rate Differential (¢/kWh) |
|---|---|---|
| **Base Case** | 5.4 | 2.1 |
| **Higher Renewable Power Prices** | 6.6 | 1.8 |

---

[39] Investment Tax Credit (ITC) which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain. The federal Production Tax Credit (PTC), which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.
U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc; U.S. Department of Energy. Electricity Production Tax Credit (PTC). http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[40] The base case forecast would also be consistent with a scenario in which the tax credit expirations are delayed.

[41] Average for solar and wind utility scale generation (>3MW), not including local Alameda County generation.

## Higher Exit Fee (PCIA) Sensitivity

PG&E's PCIA exit fees are subject to considerable uncertainty. Under the current methodology, PCIA rates can swing dramatically from one year to the next, and this methodology is currently under review and may be adjusted in the coming years. MRW therefore evaluated a stress case in which PCIA rates don't fall after 2018, as anticipated in the base case, but instead remain at 2018 levels through 2030. This increases the 2030 PCIA to 250% of its base case value. The impact of this stress case is to reduce the 2017-2030 average rate differential by 0.7¢/kWh relative to the base case.

**Table 11. Higher PCIA Exit Fee Sensitivity Results, 2017-2030**

| | Average PCIA Rate (¢/kWh) | Average Rate Differential (¢/kWh) |
|---|---|---|
| **Base Case** | 1.4 | 2.1 |
| **Higher Exit Fees (PCIA)** | 2.1 | 1.4 |

## Higher Natural Gas Prices Sensitivity

Natural gas prices have been low and relatively steady over the last few years, but they have historically been quite volatile and subject to significant swings from local supply disruptions (*e.g.*, Hurricanes Katrina and Rita in 2005). MRW analyzed a gas price sensitivity case using the U.S. Energy Information Administration's High Scenario natural gas prices forecast,[42] which is up to 60% higher than MRW's base case forecast in some years. Natural gas price increases affect power supply costs for both Alameda County CCA and PG&E; however, the nuclear and hydroelectric capacity in PG&E's resource mix makes PG&E less sensitive than Alameda County CCA to changes in natural gas prices. The net effect of higher natural gas prices is therefore to increase CCA rates relative to PG&E rates[43] (i.e., reduce the average rate differential). Under the sensitivity conditions considered, the 2017-2030 average rate differential decreases relative to the base case by 0.9¢/kWh.

[42] U.S. Energy Information Administration. "2015 Annual Energy Outlook," Table 13

[43] For the Scenario 3 the high gas natural prices case is favorable (i.e., the rate differential is higher than the rate differential for the Base Case).

**Table 12. Higher Natural Gas Prices Sensitivity Results, 2017-2030**

| | Average Natural Gas Price ($/MMBtu) | Average Rate Differential (¢/kWh) |
|---|---|---|
| **Base Case** | 4.85 | 2.1 |
| **Higher Natural Gas Prices** | 7.67 | 1.2 |

## Lower PG&E Portfolio Cost Sensitivity

While changes to natural gas prices and renewable power prices affect both the CCA and PG&E, dampening the impact on the CCA's cost competitiveness, reductions to the costs to operate and maintain PG&E's nuclear and hydroelectric facilities would provide cost savings to PG&E that would not be offset by cost savings to the CCA. MRW considered a case in which PG&E's overall generation rates are 10% below the base case, driven by reductions to PG&E's nuclear and hydroelectric portfolio costs. Under such a scenario, the 2017-2030 average rate differential would be reduced by 1 cent per kWh relative to the base case scenario.

**Table 13. Lower PG&E Portfolio Sensitivity Results, 2017-2030**

| | Average PG&E Rate (¢/kWh) | Average Rate Differential (¢/kWh) |
|---|---|---|
| **Base Case** | 10.4 | 2.1 |
| **Lower PG&E Portfolio Costs** | 9.3 | 1.1 |

## Stress Case and Sensitivity Comparisons

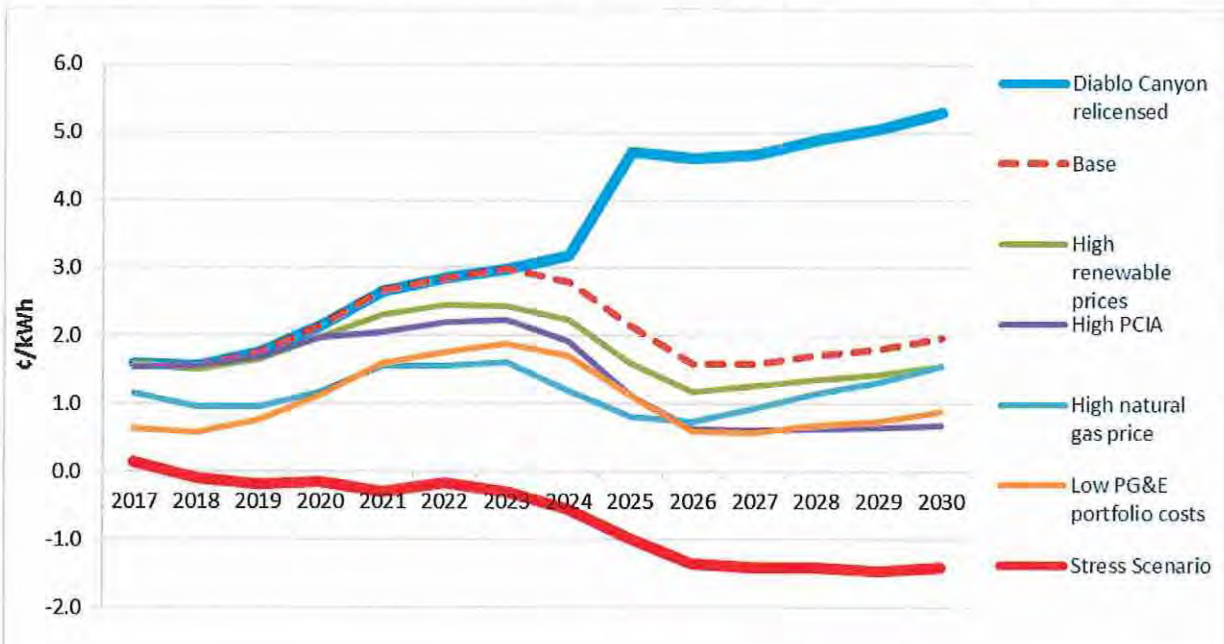
For all but the Diablo Canyon relicensing case, rate differentials (*i.e.,* the CCA's competitive positions) are lower in the sensitivity cases than in the base case scenario, for all years from 2017 to 2030 (Figure 21). To evaluate a more extreme scenario, MRW developed a stress case that combines all the negative sensitivity cases: (1) higher renewable power prices, (2) lower PG&E portfolio costs, (3) higher PCIA exit fees, and (4) higher natural gas prices. The 2017-2030 average rate differential for this stress case is negative, at -0.7¢/kWh, meaning that CCA customer costs would exceed PG&E customer costs under this scenario.

**Table 14. Stress Test Results, 2017-2030**

| | Average Rate Differential (¢/kWh) |
|---|---|
| Base | 2.1 |
| Stress Scenario | -0.7 |

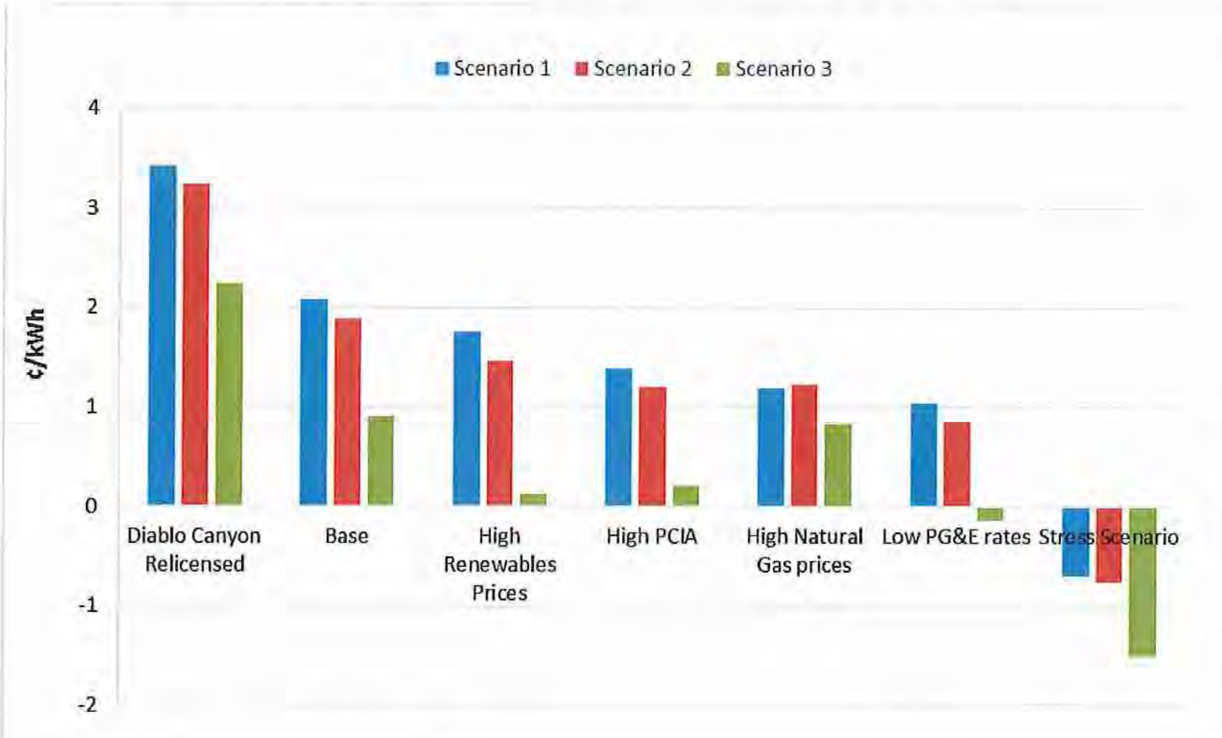
Figure 21 shows the difference between the PG&E customer rate and the Alameda County CCA customer rate (including exit fees) in the base case and in each of the sensitivity scenarios, for each year from 2017 to 2030. As Figure 21 illustrates, CCA customer rates are lower than PG&E customer rates in each of the individual sensitivity cases in each year and are lower that PG&E customer rates in the stress test case from 2017-2023. Beginning in 2024, CCA customer rates exceed PG&E customer rates in the stress test case (*i.e.*, the rate differential is negative) due to the reduction in PG&E rates as Diablo Canyon is retired and replaced with lower-cost power sources.

**Figure 21. Difference Between PG&E Customer Rates and CCA Customer Rates Under Each Sensitivity Case, 2017-2030**



The results shown above reflect the RPS Compliance supply scenario. MRW additionally evaluated each sensitivity scenario under the two alternative supply scenarios: (1) Accelerated RPS and (2) 80% RPS by 2021. Figure 22 depicts the average rate differentials for 2017-2030 for each sensitivity case under the three supply scenarios.

**Figure 22. Difference Between PG&E Customer Rates and CCA Customer Rates Under Each Sensitivity Case and Supply Scenario, 2017-2030 Average**




Scenario 1 (RPS Compliance) is the least costly scenario for the CCA and therefore has the highest rate differential under most of the sensitivity cases considered. Scenario 2 (Accelerated RPS), though still quite competitive with PG&E, fares slightly worse, with a rate differential approximately 8% lower than in Scenario 1 for most of the sensitivity cases considered. The one exception is the "High Natural Gas Price" sensitivity case, in which Scenarios 1 and 2 have about the same results. This is due to the higher renewable content in Scenario 2, which makes the supply portfolio less susceptible to volatility in natural gas prices than Scenario 1. Scenario 3 (80% RPS by 2021) has the highest renewable content and is the costliest scenario, with rate differentials much lower than those in Scenario 1 and Scenario 2. Scenario 3 is anticipated to be competitive with PG&E in most cases (on average); however, the margins are much lower, particularly in the "High Renewable Prices" sensitivity case, and they become negative in the "Low PG&E rates" sensitivity case (*i.e.,* CCA customer rates are higher than PG&E rates). On

the other hand, Scenario 3 is relatively unaffected by the "High Natural Gas Prices" sensitivity case due to the lower share of natural gas power in this supply portfolio.

In the stress case, Alameda County CCA customer rates exceed PG&E customer rates on average over the 2017-2030 period for all three scenarios, with the rate differential being highest in Scenario 3 at -1.5¢/kWh. This is double the Scenario 2 stress case rate differential of -0.75¢/kWh.

## Conclusions

Under the base case scenario, Alameda County CCA customer rates compare quite favorably to PG&E rates in all years from 2017 to 2030, under all three supply scenarios. Furthermore, under the base supply scenario (RPS compliance), Alameda County CCA customer rates remain below PG&E rates under all but the most extreme sensitivity case considered. However, under the alternate supply scenarios, as the CCA renewable content increases, the CCA becomes less completive with PG&E. This is especially pronounced in the 80%-by-2021 scenario, which shows marginal or negative competitiveness *vis a vis* PG&E in a number of scenarios. Under the stress case, irrespective of the supply scenario considered, CCA rates are higher than PG&E rates. While the stress case may appear extreme given that it involves four adverse sensitivities simultaneously occurring, cost volatility in the power industry is well-established, and the possibility of adverse conditions arising should be understood and planned for in any CCA venture.

# Chapter 5: Macroeconomic Impacts

Each of the three scenarios discussed thus far is next examined for job impacts within Alameda County. To understand just how job impacts can come about, and the extent of those changes (plus or minus), a brief description of elements associated with the CCA and how they influence the existing economy is provided.

## How a CCA interacts with the Surrounding Economy

The establishment and operation of a CCA creates a new set of spending (also referred to as demands) elements as a community changes the type of electricity generation they want to purchase, where the new mix of generation is (to be) located, adjustments necessary for existing generating assets of the provider utility, and implications on customers' bills as a result of retail rate differentials. Some of these new elements have temporary effects, while others have long-term effects. Investment in locally situated elements (such as operation & maintenance) will result in the direct creation of jobs, and when a job is created in a sector, there will be a multiplier response on "backwardly-linked" jobs with supplier businesses. The new elements include:

- Administration – [direct jobs, long-term effect] county staffing, professional-technical services and I/T-database services
- Net Rate Savings (or bill savings) – [long-term effect] county households have an increase in their spending ability, county commercial and industrial energy customers experience a reduction in their costs-of-doing business which makes them each more competitive, garnering more business that requires more employees, and municipal energy customers can provide more local services which requires more local government staff.
- New Renewable Capacity Investment within County – [direct jobs, short-term]
- New Renewable Operations within County – [direct jobs, long-term]
- New Energy-efficiency within County – [direct jobs, short-term]
- Net Generating Capacity and Operations offsets for PG&E outside of county – [direct jobs, short & long-term]

To frame expectations around how many direct jobs can be created in the county from the above CCA elements, consideration must be given to (a) how much of the spending associated with the CCA scenario is fulfilled by a within county business or resident workforce, and (b) what do these locally-fulfilled dollars represent in terms of current annual county business activity, e.g. is this a large spending event.

Table 15 presents these considerations, which are shaped in part by assumptions defined by the MRW study team. For instance, the labor share required on the annual investments (or the operating budget) was assumed to be 100 percent satisfied by within county resident laborers.

**Table 15. Initial Investment within Alameda County from Proposed CCA**

| | 2017 to 2030 | | | |
|---|---|---|---|---|
| CCA Scenario | Local Capture on RE investments (billion$) | As % of County's Total RE investment | As % of County's Expected Economic Activity | Bill Savings (billion$) |
| 1 | $0.42 | 44% | 0.01% | $1.57 |
| 2 | $0.42 | 44% | 0.01% | $1.51 |
| 3 | $0.45 | 45% | 0.01% | $0.52 |

As can be seen from the table, the initial local investment that would result from building and operating additional renewable projects in Alameda County between the years 2017 to 2030 represents a very small portion of the County's total expected economic activity, [44] even assuming all of the project costs are directed locally (usually 56% of the project costs would be funneled outside the county due to procurement of equipment from outside the county). By contrast bill savings for scenarios 1 and 2 provide over three fold the benefits of initial local investment. These bill savings indirectly stimulate the economy and ultimately create jobs.

Table 16 illustrates this through high-level results expressed as average annual job changes for the three CCA scenarios. While scenarios 1 and 2 create nearly identical direct jobs (due to comparable investment in local renewable projects), scenario 1 creates far more TOTAL jobs. This is due to the higher bill savings under scenario 1. Scenario 3 creates a few more direct jobs, but far fewer total jobs, due to decreased bill savings as compared to the other two scenarios. As a result, its total job impact is 55 percent of the scenario 1 total job impact. A more detailed discussion of these results will follow later.

**Table 16. Average Annual Jobs created in Alameda County by the CCA – Direct and Total Impacts**

| | 2017 – to – 2030 | | County Impacts | |
|---|---|---|---|---|
| CCA Scenario | Local Capture on RE investments (billion$) | Bill Savings (billion$) | Average Annual DIRECT Jobs | Average Annual TOTAL Jobs |
| 1 | $0.42 | $1.57 | 165 | 1322 |
| 2 | $0.42 | $1.51 | 166 | 1286 |
| 3 | $0.45 | $0.52 | 174 | 731 |

[44] Forecast to be $3,500 billion (nominal). Source REMI Policy Insight model, Alameda County forecast.

## How Job Impacts Are Measured

The scenario-specific elements described in the prior section are expressed as annual dollar amounts (plus or minus) in comparison to what would have been expected in the county economy without a CCA. Initially these amounts supplied by MRW and Tierra are general, representing total project cost by year. The annual investment for specific types of renewable energy projects and of making further energy-efficiency improvements are really comprised of some portion spent on installation labor, a large portion for the equipment (either manufactured in the region or if not, a leakage to imports), and some small portion soft project costs. These details are necessary for modeling impacts on the county economy due to a CCA program.

A macroeconomic impact (industry) forecasting model of Alameda County[45] is used, the dollar amounts, with further data refinement (detail) are introduced to the model, the economy adjusts to these spending and savings changes by year and then identifies annual impacts in terms of dollar concepts (wages, sales, prices, gross regional product) and jobs, among numerous other metrics. Appendix E provides some high-level background on the REMI Policy Insight model. This model was chosen since it is uniquely qualified over other models and approaches to understand how price (or rate) changes on the business segment (Commercial /Industrial energy customers) influence business activity levels. Since electric rate differentials are a key consideration in pursuing a CCA, the study required a method that would adequately address this.

## Scenario Results

MRW created the three supply scenarios by considering how much within county RE investment (for future generating assets) the CCA could fund, and how much it might invest elsewhere in California (rest of California or "roCA"). Program administration and energy efficiency deployment investments are the same in all three scenarios. As can be seen from Table 17, scenario 3 has the most proposed CCA renewables investment within county but, it has the lowest bill savings. In contrast scenario 1 would site a smaller renewables investment by the CCA as within county, but has proportionally much higher bill savings.

[45] The model is a Policy Insight model by Regional Economic Models, Inc. (REMI) of Amherst, MA. It is a model that has been used by the CA Energy Commission, CALTrans, Los Angeles MTA, ABAG, City of San Francisco, and the South Coast AQMD. For this study a two-region socio-economic forecasting model (the county, and balance of State) with 23- industries was used.

**Table 17. Initial Comparison of Proposed CCA Scenarios**

| 2017 to 2030 | Million$ nominal | Million $ nominal DEMAND | | | | | |
|---|---|---|---|---|---|---|---|
| Scenario | Bill Savings | CCA Renewable Investment | | | CCA Renewable O&M | | PG&E Offset Renew. O&M |
| | | Alameda Co. | rest of CA | PG&E offset RE invest. roCA | Alameda Co. | rest of CA | Alameda |
| 1 | $1,574 | $623 | $1,676 | -$1,946 | $47 | $133 | -$153 |
| 2 | $1,513 | $623 | $2,217 | -$2,446 | $47 | $190 | -$206 |
| 3 | $522 | $674 | $2,514 | -$2,785 | $51 | $200 | -$219 |

Note: Customers' bill savings account for PG&E's indifference charge, and any out-of-pocket expenditures for customer-sited renewable or efficiency projects.

## Job and Gross Regional Product Total Impacts

The yearly profile for the county's total impacts – whether as jobs (Figure 23) or dollars of gross regional product (GRP) (

Figure 24) – shows that scenario 1 outperforms the other two scenarios. All scenarios share the year 2023 as the year of maximum positive impact which is due to maximum net rate savings. The cumulative GRP impact through 2030 for scenario 1 represents a 0.12% change relative to the county's forecasted GRP without a CCA.

**Figure 23. Alameda County Total Job Impacts by Scenario**

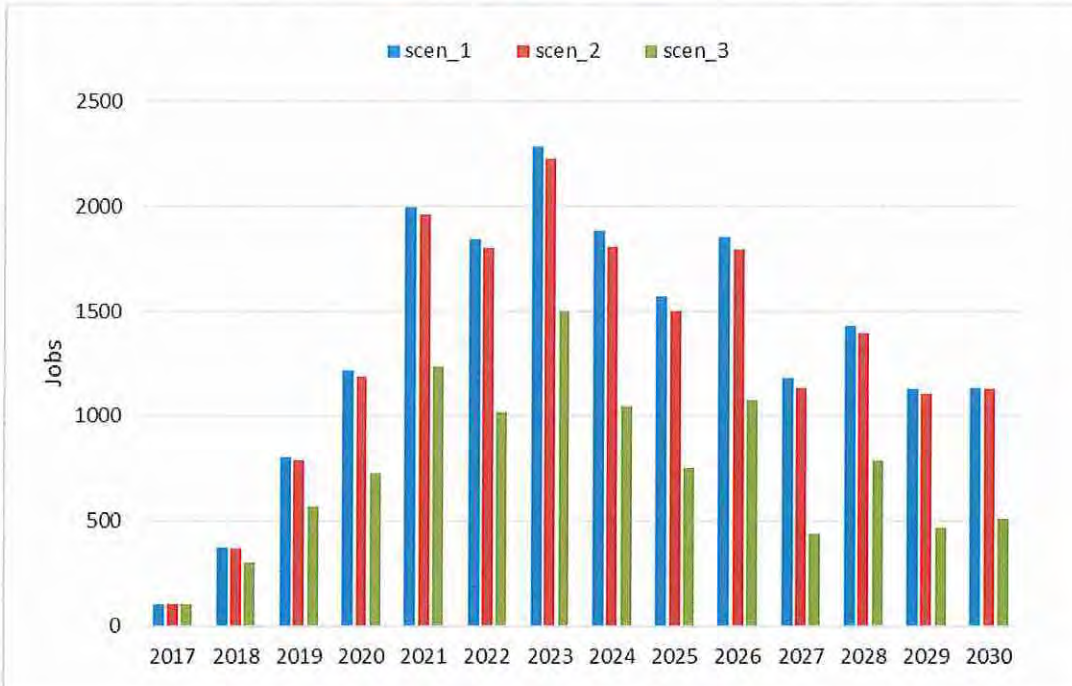
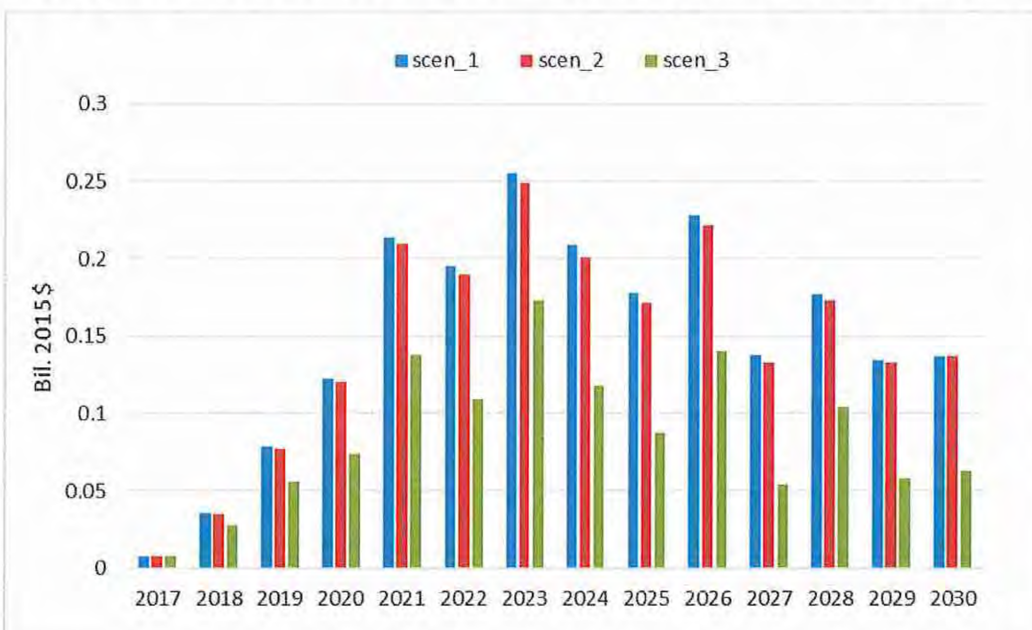



**Figure 24. Alameda County Total Gross Regional Product Impacts by Scenario**



**County Job impact by Stage of Job generation, Scenario 1**

Job changes typically start from a direct productive event that alters the need for labor, such as constructing a facility or opening/closing a business. Then there are the local cycles of business-to-business supplier transactions that follow (called indirect jobs), cycles of household spending from the direct and indirect paychecks (called induced jobs), and sometimes there are job changes due to changes in costs (rates) of a location which affect doing-business in the county. These are job impacts from competitiveness effects. The indirect and induced combined are referred to as multiplier effects. The total job impact reflects the direct, the multiplier, and the competitiveness effects. Figure 25 juxtaposes the county's direct job impacts with the total job impacts from Scenario 1. The majority of job creation in the scenario is from non-direct economic influences - specifically from the net rate savings which drives approximately 76 percent of the county's job gain (Figure 26). As shown in Appendix E, Scenario 2 would have an identical profile of direct jobs but a slightly lower total job profile, due to almost $60 million of curtailed net rate savings (relative to scenario 1) through 2030. Scenario 3 has a slightly higher direct job profile but a greatly reduced total job impact profile.

**Figure 25. CCA Scenario 1 County Job Impacts**

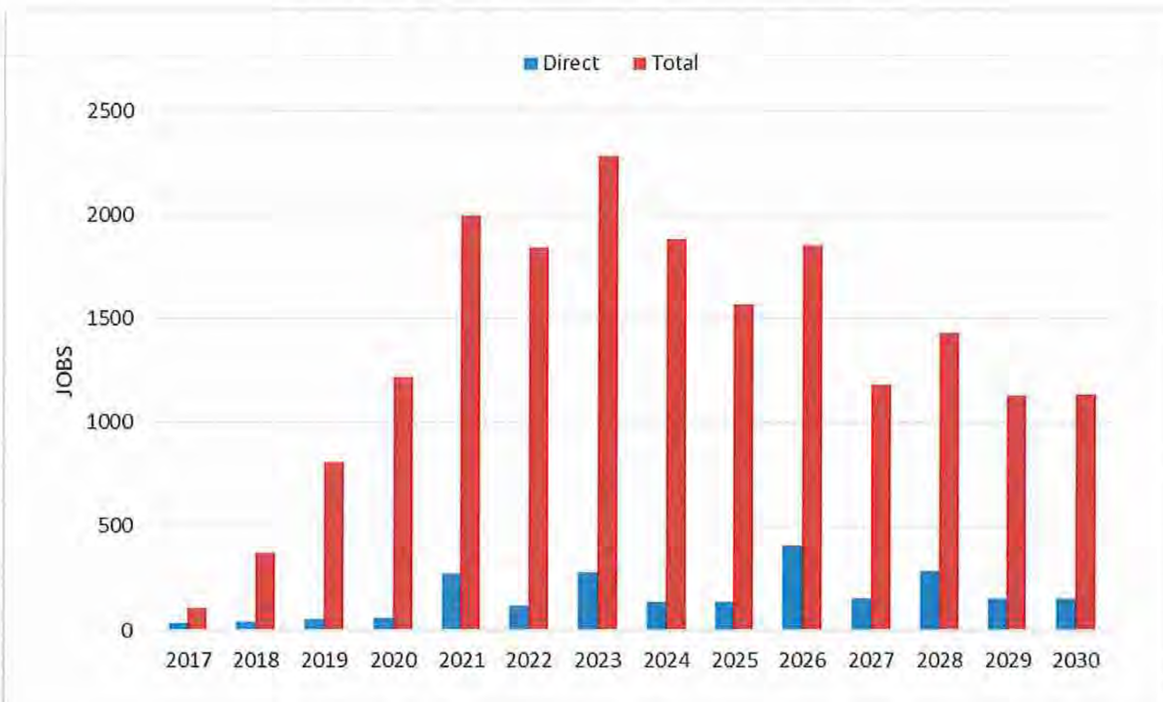
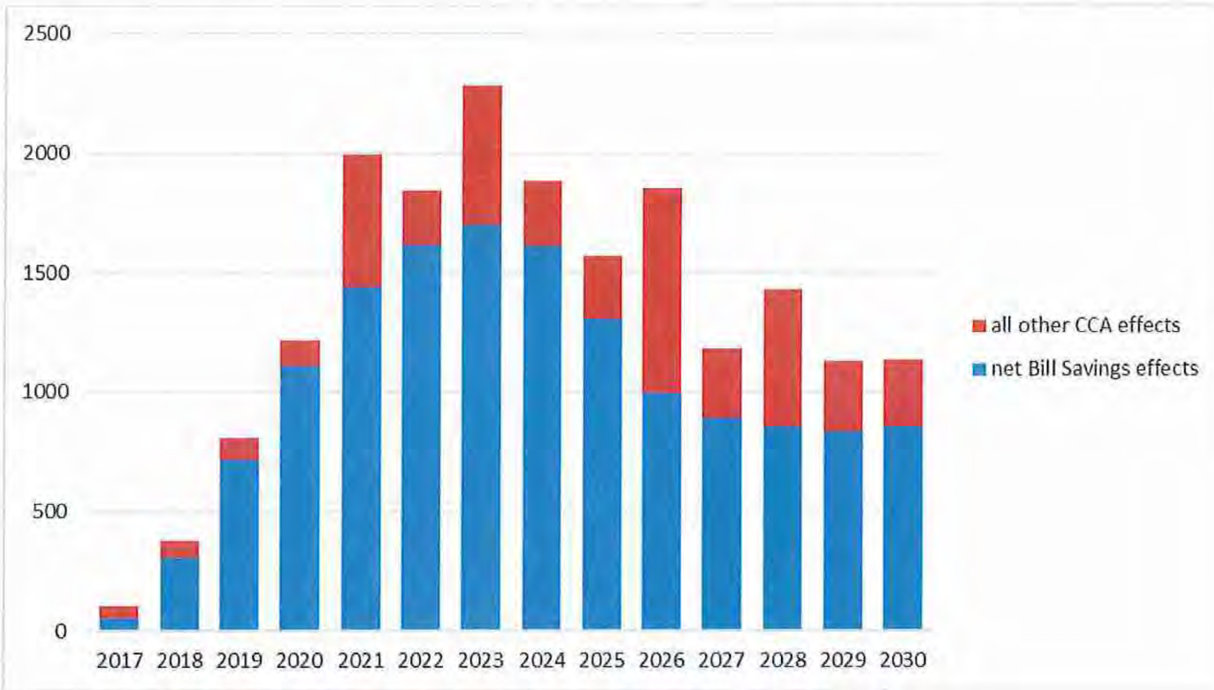


**Figure 26. Alameda County CCA Scenario 1 Total Jobs Impacts by Source**




## County Job Impacts by Sector 2023 (Scenario 1)

The county's sectors which will create these jobs are shown next in Figure 27. The year 2023 is selected since it is when the maximum job impact was shown. Not all sectors are involved with CCA activities (the absence of direct jobs) but all do experience business growth -hence added jobs- as a result of multiplier effects and competitiveness effects. The per-worker 2023 (forecasted and nominal) earnings rate is shown to the right of the sector name. The average (weighted) annual earnings implied across the 2,282 jobs gained within the county in 2023 is $102,120.

The results of the other two Scenarios are found in Appendix E.

**Figure 27. Alameda County Jobs Changes by sector (annual earnings per worker), 2023**


## Focus on Construction Sector Jobs

The county economy does not forfeit Construction sector jobs (nor does the balance of California economy). In fact, as Figure 27 shows, Construction experiences the largest direct (136 jobs) and total job change (440) for 2023 among all sectors. The degree to which any of these jobs are held by union members or equivalently non-union laborers "working under a collective bargaining agreement (CBA)" is addressed by understanding the publicly available data sources that are used in calibrating any region of a REMI model. It should be noted that the REMI model does not carry a union segmentation on the industry specific employment data. REMI relies upon data series from the U.S. Department of Labor, Commerce and Census. All the data products are the result of states providing a mix of annual and quarterly reports. A consistent characterization of REMI's Construction sector employment is obtained from (Census') the

Current Population Survey – Earnings Report (2014) which for California shows approximately 20 percent of construction employment is engaged in work 'covered' by a CBA.[46] Again those working under a CBA need not all be union members. The Construction sector activity in the two-region REMI model is therefore a blend of work, (20:80) covered-to-non-covered projects.

Table 18shows average annual direct and total job impacts by scenario and how many occur in the Construction sector and which would be "covered" by a CBA. Because the direct construction jobs (in particular) vary markedly from year to year (depending upon if a generation project is under construction or not, it is informative to look at a single year). Table 19 shows the construction jobs in 2023, the peak year for direct construction activity. As the table shows, when a project is utility-scale is under construction, the construction jobs increase to about ten times the average number.

**Table 18. County's Average Annual Construction Job Impacts**

| Scenario | Jobs in All Sectors | | Jobs in Construction Sector | | Jobs Associated with CBA | |
|---|---|---|---|---|---|---|
| | Direct | Total | Direct | Total | Direct | Total |
| 1 | 165 | 1322 | 80 | 235 | 16 | 47 |
| 2 | 166 | 1286 | 81 | 231 | 16 | 46 |
| 3 | 174 | 731 | 86 | 160 | 17 | 32 |

**Table 19. Peak-Year Construction Job Impacts**

| CCA Scenario | Jobs in Construction Sector | | Jobs Associated with CBA | |
|---|---|---|---|---|
| | Direct | Total | Direct | Total |
| 1 | 136 | 440 | 27 | 88 |
| 2 | 137 | 432 | 27 | 86 |
| 3 | 154 | 326 | 31 | 65 |

The CBA distinction is important as it uses the prevailing hourly wage set by the CA Dept. of Industrial Relations[47] for public-funded projects. It is premature to determine how much of the

[46] www.unionstats.com
[47] See page 49 of http://www.dir.ca.gov/oprl/pwd/Determinations/Northern/Northern.pdf

proposed CCA renewable capacity in any of the scenarios would indeed be public-funded (as opposed to power purchase agreements with third party private project developers). The straight-time[48] prevailing hourly "covered" wage rate for FY2016 in the northern counties (including Alameda County) for Group 3 construction laborers is $49.74 which is 21 percent higher than the market rate (indicative of the aforementioned 20:80 blend) of $40.96 in the REMI model.

A sensitivity run (Table 20) was conducted just for the macroeconomic impacts that considers 100 percent union or "covered" labor for the direct effect only. This did not require MRW to inflate the renewable project costs and then recalculate forecasted CCA electric rates as would be warranted. Instead – for scenario 1- the fixed (NREL JEDI model derived) labor share on MRW's initial annual renewable investment would hire fewer but better paid (by 21 percent) construction laborers. As Table 20 shows, the prevailing wage sensitivity has 13 fewer average annual direct (Construction) jobs but the gain in direct "covered" jobs means 51 construction laborers would be paid more.

**Table 20. Scenario 1 Sensitivity on Direct Construction Requirements**

| | Market Wage (20% covered: 80% not covered) | Prevailing Wage (100% covered) |
|---|---|---|
| **Scenario Direct Jobs** | **165** | **152** |
| As Construction | 80 | 67 |
| UNION (Covered) | 16 | 67 |
| Non-UNION | 64 | 0 |
| | **Market Wage (20% covered: 80% not covered)** | **Prevailing Wage (100% covered)** |
| **Scenario Total Jobs** | **1343** | **1321** |
| As Construction | 235 | 221 |
| UNION (Covered) | 47 | 98 |
| Non-UNION | 188 | 123 |

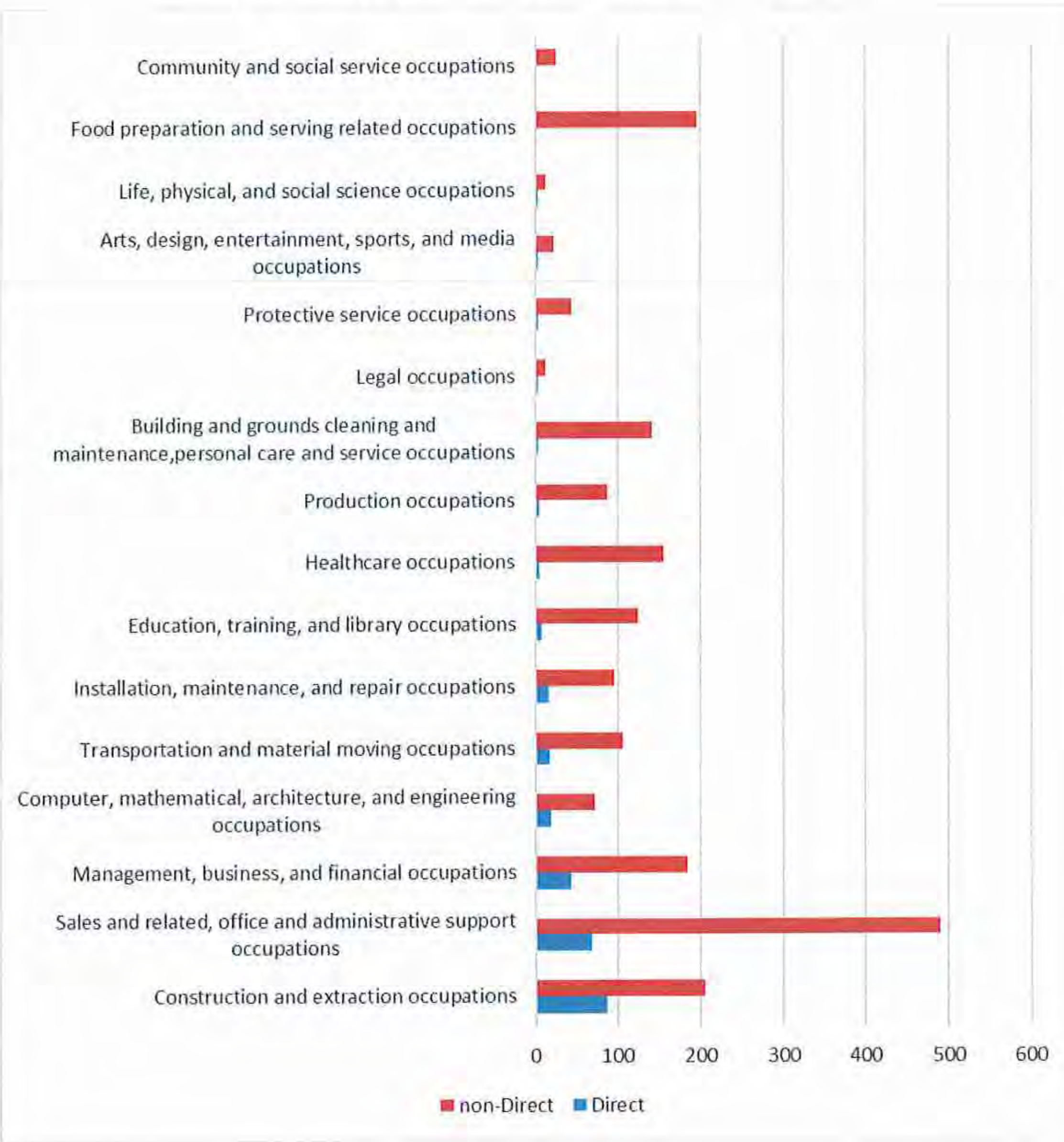
The other approach to testing this sensitivity would entail inflating the annual investment cost on renewable projects by the 21 percent labor premium, restating a higher set of CCA electric rate projections (from these renewable capacity additions) than the current report is based upon, leading to a reduced 'rate savings' effect. This would more drastically dampen the macroeconomic impacts than shown in Table 20since the net rate savings have been shown to account for 76 percent of the county's positive job impacts.

48 Current Employer Statistics data for 2014 show on average a 40-hour work week in the Construction sector.

### Occupation Impacts for Alameda County, 2023

Sectors that experience job changes will mean changes over a mix of their occupational requirements. For the maximum year of county job impact, 2023, the broad category occupational impacts are presented in Figure 28 for Scenario 1 as relates to the direct jobs and the non-direct jobs (direct plus non-direct equals the total jobs). They are shown in ascending order of direct stage occupational requirements. It should not be surprising that the non-direct stage of economic stimulation for the county creates a more pronounced set of occupational opportunities due to the magnitude of net rate savings benefitting all customer segments within the county. Note Military and Farming occupations are omitted due to zero or very small response in both stages of job generation.

**Figure 28. Occupational Impacts Scenario 1, 2023**



# Chapter 6: Other Risks

Aside from the risks identified above, the CCA or the political jurisdictions that are part of the CCA could be at risk. This section addresses some of those risks.[49]

## Financial Risks to CCA Members

A CCA is effectively an association of various political subdivisions. The formation documents for the CCA define the rights and responsibilities of each member of the CCA. Given the large number of political subdivisions that might participate in an Alameda County CCA, MRW assumes that the Alameda County CCA would be formed under a Joint Powers Authority, in much the same way as MCE Clean Energy and Sonoma Clean Power.

The CCA will ultimately take on various financial obligations. These include obtaining start-up financing, establishing lines of credit, and entering into contracts with suppliers. Because a CCA will take on such financial obligations, it is likely very important to the prospective member political subdivisions that the financial obligations of the CCA cannot be assigned to the members.

As a result, it is critical that the Joint Powers Authority and any other structuring documents are carefully drafted to ensure that the member agencies are not jointly obligated on behalf of the CCA (unless a member agency chooses to bear such obligations). The CCA should obtain competent legal assistance when developing the formation documents.[50]

## Procurement-Related Risks

Because a CCA is responsible for procurement of supply for its customers, the CCA must develop a portfolio of supply that meets the resource preferences of its customers (e.g., ratio of renewable versus non-renewable supply) while controlling risks (e.g., ratio of short-term versus long-term purchase agreements) and meeting regulatory mandates (e.g., resource adequacy and RPS requirements). Thus, it is tempting to assume that customers would prefer a fully hedged supply portfolio. However, such insurance comes at a cost and a CCA must be mindful of the potential competition from PG&E. As a result, the CCA's portfolio must be both flexible while meeting the needs of its customers.

The CCA will likely need to negotiate a flexible supply arrangement with its initial set of suppliers. Such an arrangement is important since the CCA's loads are highly uncertain during CCA ramp-up. Without such an arrangement, the CCA faces the risk of either under- or over-procuring renewable or non-renewable supplies. Excessive mismatches between supply and demand of these different products would expose the CCA's customers to major purchases or sales in the spot markets. These spot purchases could have a major impact on the CCA's financials.

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[49] Note that this section does not provide legal opinion regarding specific risks, especially those related to the formation or the structure of the Joint Powers Authority under which MRW assumes the CCA will be established.
[50] Cities such as El Cerrito and Benicia have conducted legal analyses when they were considering joining MCE. which should also be consulted.

The CCA will by necessity have to procure a certain amount of short-term supplies. These short-term supplies bring with them price volatility for that element of the supply portfolio. While this volatility is not unexpected, the CCA must be mindful that such volatility could increase the need for reserve funds to help buffer rate volatility for the CCA's customers. Funding such reserve funds could be challenging in this time of low gas prices (resulting in high PCIA charges).

The CCA will be entering the renewable market at an interesting time. While all LSEs must meet the expanded RPS targets by 2030, at least the IOUs are currently over-procured relative to their 2020 RPS targets. Whether the IOUs will attempt to sell off some of their near-term renewable supplies is unknown. However, if the IOUs believe that this is a good time to acquire additional renewables, the CCA could face stiff competition for renewable supplies, meaning that the green portfolio costs for the CCA might be higher than expected.

Finally, it should be noted that as greater levels of renewables are developed to meet the State's very aggressive RPS goals, it is possible that the traditional peak period will change. Adding significant amounts of solar could depress prices during the middle of the day. This could result in the need to try to sell power to out-of-state market participants during the middle of the day, possibly even at a loss. It could also result in the curtailment of renewable resources (even resources owned or controlled by the CCA). This could force the CCA to acquire greater levels of renewable supplies, thereby increasing costs.

## Legislative and Regulatory Risks

As noted above, the CCA must meet various procurement requirements established by the state and implemented by the CPUC or other agencies. These include procuring sufficient resource adequacy capacity of the proper type and meeting RPS requirements that are evolving.[51] Additional rules and requirements might be established. These could affect the bottom line of the CCA.

## PCIA Uncertainty

Assembly Bill 117, which established the CCA program in California, included a provision that states that customers that remain with the utility should be "indifferent" to the departure of customers from utility service to CCA service. This has been broadly interpreted by the CPUC to mean that the departure of customers to CCA service cannot cause the rates of the remaining utility "bundled" customers to go up. In order to maintain bundled customer rates, the CPUC has instituted an exit fee, known as the "Power Charge Indifference Adjustment" or "PCIA" that is charged to all CCA customers. The PCIA is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCA service are not shifted to remaining PG&E bundled service customers.

Even though there is an explicit formula for calculating the PCIA, forecasting the PCIA is difficult, since many of the key inputs to the calculation are not publicly available, and the results are very sensitive to these key assumptions. For PG&E, the PCIA has varied widely; for example, at one time the PCIA was negative.

[51] Rules to establish RPS requirements under the new 50% RPS mandate are currently being debated at the CPUC.

Current CCAs have chosen to have customers bear the financial risk associated with the level of exit fees they will pay to PG&E. Thus, for a customer taking CCA service to be economically better off (i.e., pay less for electricity), the sum of the CCA charges plus the PCIA must be lower than PG&E's generation rate.

This risk can be mitigated in two ways. First, as discussed in more detail elsewhere, a rate stabilization fund can be created. Second, the CCA can actively monitor and vigorously participate in CPUC proceedings that impact cost recovery and the PCIA.

## Impact of High CCA Penetration on the PCIA

Currently, the PCIA calculation is based on the cost and value of a utility's portfolio, without regard to how much of that portfolio is to be paid for by bundled customers and how much by Direct Access (DA) and CCA customers. As such, the PCIA is not affected by the number of DA/CCA customers.

Currently, for bundled customers the rate impacts associated with fluctuating PCIAs are relatively small, but this will change as the number of DA/CCA customers grows. At some point, bundled customers' rates may experience marked volatility as the impacts of the annual PCIA rate swings reverberate to bundled rates. This may be unacceptable to ratepayer advocates and the Commission.

The PCIA rate volatility in part reflects changes to the utilities generation costs, which is appropriately reflected in bundled customers' rates. But, often to a large degree, it reflects changes to the market price benchmark, which should not be relevant to bundled customer rates. For a utility with flat RPS costs, this would have increased the RPS-related PCIA, which would have reduced bundled rates, even though there was no change in RPS costs. This could also happen in the reverse direction, increasing bundled rates when there is no increase in underlying generation costs.

Once DA/CCA load gets large enough that there are real stranded contracts, we suspect that the Commission is going to look much more closely at the value of these stranded contracts (and how to get the most value for them).

## Impact of High CCA Penetration Low-Carbon Resources

Virtually all the CCAs forming in California include carbon reduction as a goal. As the analysis has shown, CCAs will likely need to purchase carbon-free both qualifying renewables and other, to meet their goals. This increased demand for carbon-free power will change the "supply-demand" balance and in theory increase the cost of these resources. To address this risk, the Alameda County CCA should consider locking in longer-term contracts for non-RPS eligible resources early in the process so as to guarantee their availability in the longer term when there could be greater demand for them.

## Bonding Risk

Pursuant to CPUC Decision 05-12-041, a new CCA must include in its registration packet evidence of insurance or bond that will cover such costs as potential re-entry fees, specifically, the cost to PG&E if the CCA were to suddenly fail and be forced to return all its customers back to PG&E bundled service. Currently, a bond amount for CCAs is set at $100,000.

This $100,000 is an interim amount. In 2009, a Settlement was reached in CPUC Docket 03-10-003 between the three major California electric utilities (including PG&E), two potential CCAs (San Joaquin Valley Power Authority and the City of Victorville) and The Utility Reform Network (TURN) concerning how a bonding amount would be calculated. The settlement was vigorously opposed by MCE and San Francisco and never adopted.

Since then, the issue of CCA bond requirements has not been revisited by the CPUC. If it is, the bonding requirement will likely follow that set for Energy Service Providers (ESPs) serving direct access customers. This ESP bond amount covers PG&E's administrative cost to reintegrate a failed ESP's customers back into bundled service, plus any positive difference between market-based costs for PG&E to serve the unexpected load and PG&E's retail generation rates. Since the ESP bonding requirement has been in place, retail rates have always exceeded wholesale market prices, and thus the ESP's bond requirement has been simply the equal to a modest administrative cost.

If the ESP bond protocol is adopted for CCAs, during normal conditions, the CCA Bond amount will not be a concern. However, during a wholesale market price spike, the bond amount could potentially increase to millions of dollars. But the high bond amount would likely be only short term, until more stable market conditions prevailed. Also it is important to note that high power prices (that would cause a high bond requirement) would also depress PG&E's exit fee and would also raise PG&E rates, which would in turn likely provide the CCA sufficient headroom to handle the higher bonding requirement and keep its customers' overall costs competitive with what they would have paid had they remained with PG&E. As discussed above, JPA member entities would not be individually liable for any increase in the bond amount.

# Chapter 7: Other Issues Investigated

## Funding, Costs, and Impacts of the Energy Efficiency Program Scenario

Having established that both adequate economic and market potential exist beyond what is currently being targeted through PG&E programs, the MRW Team estimated how much efficiency could reasonably be captured by assessing the availability of funding for energy efficiency, and the cost of to acquire it through various programs. Understanding available funding options and costs allowed the MRW team to determine the amount of energy efficiency that could be acquired in various funding options and use this to calculate the economic inputs for the REMI model.

To assess funding, CCA's have several funding options, including;

- Funds from Non-bypassable Electric Charges – CPUC Ruling R.09-11-014 defined various funding options for CCAs that are administrators of energy efficiency programs, and also outlined some of the funding authorities available to CCA's that elect to not administer programs
- Funds from Non-bypassable Gas Charges – CPUC Decision D.14-10-046 allows CCA's to administer programs that include funds collected from natural gas customer. This analysis did not estimate the value of these funds.
- Income from CCA Operations. Income generated through CCA operations may be used to fund customer programs.
- Funding secured by aligned organizations, such as StopWaste's Energy Council, on behalf of a CCA.
- Increased funding through the expansion of the CCA territory. Under current regulations it is allowed for a CCA to define its service territory more broadly than a city or county. As such, the rules that define the funding for Alameda County residents would apply to new participants in a CCA and so provide incremental program funding. For example, in 2015 Marin Clean Energy began serving customer in Contra Costa County and has increased its available program funding as a result of this enrollment.

This analysis only considered the impact of Non-bypassable Electric Charges. Using rules defined in CPUC Ruling R.09-11-014 and various cost reports[52], Table 21 shows that approximately $3.9M would be available for programs administered by a CCA to Alameda County residents, including both CCA and PG&E customers, or $3.5M if these programs serve only CCA customers, assuming a 15% opt-out rate.

[52] Electric and Gas Utility Cost Report. Public Utilities Code Section 913 Report to the Governor and Legislature, April 2016.

**Table 21. Annual Funding Models for Non-bypassable Electric Charges**

| Annual Funding Models for Non-bypassable Electric Charges | Estimated Value |
|---|---|
| Program Administrator - CCA and PG&E customers | $3,941,000 |
| Program Administrator - CCA customer only | $3,350,000 |

The cost of energy was determined by analyzing the 2015 PG&E portfolio to identify the costs per first year net kWh for programs that are likely to be the most representative of programs administered by an Alameda County CCA. An analysis the PG&E portfolio, including the programs presented in Table 22, indicates that $0.61 per net first year kWh is a reasonable estimate of the current unit cost of energy efficiency.

**Table 22. Select Unit Costs for Energy Efficiency ($/ net kWh)**

| Program Administrator | Sub-Program Name | Percent Program Savings that are Electric | Cost Per First Year Net kWh Equivalent |
|---|---|---|---|
| PG&E | Commercial Energy Advisor | 18% | $0.18 |
| MCE | MEA 02 - Small Commercial | 79% | $0.37 |
| PG&E | Lighting Programs Total | 100% | $0.38 |
| MCE | MEA01 2013-14 MF - Multifamily | 36% | $0.59 |
| PG&E | East Bay | 93% | $0.59 |
| Third Party | RightLights | 100% | $0.75 |
| PG&E | Energy Savers | 100% | $0.81 |
| Third Party | Energy Fitness Program | 100% | $0.84 |

The MRW teams defined the level of energy efficiency input into the REMI model by dividing the available funding by the units cost of energy efficiency as defined above, using the following assumptions;

- Available annual budget for energy efficacy programs is based on the maximum funding equation provided in R.09-11-014, and assuming programs are administered only to CCA customers. As discussed in Table 21, this represents approximately $3.5M annually.
- The cost of energy efficiency programs most likely to be offered under and a CCA would be $0.61 per net first year kWh.

- The savings from energy efficiency during the forecast horizon would grow at a rate consistent with expected annual energy demand as defined in the 2015 CEC IEPR demand forecast.[53]
- Demand savings would be consistent with the ratio of demand to energy savings achieved by the programs most likely to be offered by a CCA as presented in Table 22.

Based on this methodology, Table 23 provides a summary of model energy and demand savings inputs. Note that these savings numbers are incremental to PG&E goals, which average about 42 GWh annually from 2021 through 2024, as defined in the CPUC potential model, which has a forecast horizon ending in 2024.

**Table 23. Model Energy and Demand Savings Inputs**

| Year | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Annual incremental energy savings (GWh) | 5.7 | 5.8 | 5.9 | 5.9 | 6.0 | 6.0 | 6.1 | 6.1 | 6.2 | 6.3 |
| Annual incremental demand savings (MW) | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |

## "Minimum" CCA Size?

MRW's analysis above assumed that all eligible Alameda County cities join the Alameda County CCA program with a participation rate of 85% from each city, resulting in an anticipated CCA load of about 7 million MWh per year.[54] If fewer customers join, CCA rates will generally be higher because about $8 million of annual CCA costs are invariant to the amount of CCA load. Along with the number of customers, the customer make-up is also important. For example, a higher share of residential customers would improve the competiveness of the CCA, while a higher share of commercial customers or industrial customers would weaken the competitiveness of the CCA. Since cities vary in their distribution of customers by rate class, a city opting out of the CCA could affect the competitiveness of the CCA due to both the reduction in CCA load and the shift in customer make-up.

The "minimum" load needed for CCA customer rates to be no higher than PG&E customer rates is approximately 450,000 MWh per year, assuming the average customer portfolio for Alameda County and Supply Scenario 1. This value was estimated by assuming that the fixed costs remained the same (i.e., did not scale with sales) and then lowering the sales until the hypothetical reduced CCA's rates were equal to PG&E's. As shown in Figure 29, this is roughly the load from each of the medium-sized cities (e.g., Pleasanton and San Leandro) and much smaller than the load from the larger cities (e.g., Berkeley, Oakland, and Fremont). As long as

[53] Form 1.1 - PGE Planning Area California Energy Demand 2015 Revised - Mid Demand Case. Electricity Consumption by Sector (GWh)

[54] In the alternate supply scenarios, the "minimum" annual load assuming the average customer portfolio for Alameda County and the base case is 550,000 MWh (Scenario 2) and 1,000,000 MWh (Scenario 3). These "minimum" loads are also far below the expected annual CCA load of 7 million MWh.

two medium-sized cities or one larger city joins the CCA, this "minimum" load will be met. It is not a true minimum, however, because the true minimum depends on the make-up of the customer portfolio.

**Figure 29. Potential load (85% participation) per city**

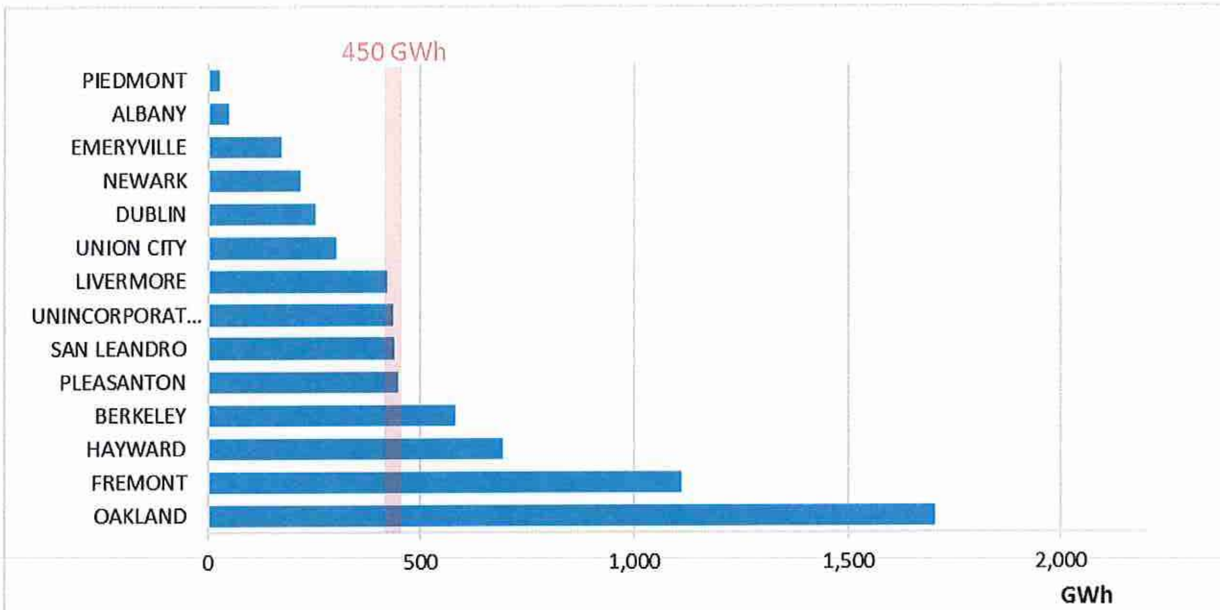



**Table 24. Examples of Combinations of Cities and the Average Generation Rate**

| Examples of city combinations | ONLY BERKELEY | | ONLY PLEASANTON | | ONLY DUBLIN + NEWARK | | TOTAL ALAMEDA COUNTY |
|---|---|---|---|---|---|---|---|
| | Potential Load (MWh) | Customer Class (%) | Potential Load (MWh) | Customer Class (%) | Potential Load (MWh) | Customer Class (%) | Customer Class (%) |
| Residential | 136,000 | 23.37% | 158,000 | 35.11% | 160,000 | 33.83% | **32.90%** |
| Commercial | 176,000 | 30.24% | 232,000 | 51.56% | 234,000 | 49.47% | **43.70%** |
| Industrial | 74,000 | 12.71% | 36,000 | 8.00% | 41,000 | 8.67% | **13.80%** |
| Public | 193,000 | 33.16% | 19,000 | 4.22% | 35,000 | 7.40% | **8.60%** |
| Street lights + Pumping | 3,000 | 0.52% | 5,000 | 1.11% | 3,000 | 0.63% | **1.00%** |
| **TOTAL** | **582,000** | | **450,000** | | **473,000** | | |
| **Average PG&E rate (¢/kWh)** | | **9.71** | | **10.56** | | **10.51** | **10.36** |
| **Average CCA rate (¢/kWh)** | | **9.92** | | **10.48** | | **10.19** | **8.28** |
| **Differential rate (¢/kWh)** | | **-0.21** | | **0.08** | | **0.32** | **2.08** |

## Individuals and Communities Self-Selecting 100% Renewables

The existing CCAs all offer customers an option to choose to receive 100% of their power from renewable resources in exchange for a rate premium. However, each CCA's program is different. MCE Clean Energy has offered its "Deep Green" at a rate premium of 1¢/kWh since its inception. Sonoma Clean Power offers its "Evergreen" option at approximately the same price as PG&E's "Solar Choice" rate. Lancaster Choice Energy offers its Smart Choice as a fixed monthly premium rather than a variable rate. In all cases, only a very modest number of CCA customers—on the order of a few percent—have selected the 100% green rate option.

**Table 25. CCA 100% Green Rate Premiums**

| CCA | Rate Option | Increment Above Default Rate |
|---|---|---|
| Marin Clean Energy | Deep Green | 1¢/kWh |
| Sonoma Clean Power | EverGreen | 3.5¢/kWh |
| Lancaster Choice Energy | Smart Choice | $10/month |
| **Potential Alameda Co. CCA** | **TBD** | **~1.5¢/kWh** |

Any full renewable pricing option offered by the Alameda County CCA would have to be set by the CCA's management. The value shown in Table 25, ~1.5¢/kWh, is the average incremental cost of green power used in the CCA supply assessment (Scenario 2) over the study period. (Initially, it would have to be ~1.9¢/kWh.) Thus the actual number of hypothetical customers selecting the rate would not impact the economics of the CCA customer who remain on the standard rate.

- Representatives from at least two communities, Berkeley and Albany, have expressed interest in having their residents and businesses default onto a 100% renewable rate. If priced at the cost of incremental renewables, such as is assumed in Table 25, then there would be no financial impact on the CCA or its remaining customers. Nonetheless, it could have implications:

- Separate CCA opt-out notifications would be needed. A key feature of the opt-out notification is the price comparisons against PG&E. As the default rate would be different for these communities, a different notice would have to be sent. This would simply increase the start-up cost for the CCA, the increment could be paid for by the city electing a different default rate.
- Having a higher default rate might increase the number of oft-outs in the community.
- PG&E's billing system would have to be able to handle city- or zip code-specific default options. That is, as new residential or businesses move to a self-selected

green community, the billing system would need to know to default them on a different rate schedule than a customer in a different CCA community. This may or may not be an issue.

## Competition with a PG&E Community Solar Program

PG&E has been offering a solar choice program known as Green Tariff Shared Renewable Program since February 2015.[55] The program was established under Senate Bill 43, and pursuant to Decision 15-01-051 from the CPUC, to extend access to renewable energy to ratepayers that are currently unable to install onsite generation.[56] It offers homes and businesses the option to purchase 50% or 100% of their energy use from solar resources. The program provides those with homes or apartments or businesses that cannot support rooftop solar the opportunity to meet their electricity requirements through renewable energy and support the growth of renewable energy resources.

PG&E's current Solar Choice program costs residential customers an additional 3.58¢/kWh. Given that MRW projects that the CCA can offer 100% green power at ~1.5¢/kWh over its own Scenario 1 or Scenario 2 rate (which is projected to be less than PG&E's), we do not see PG&E's Community Solar Program as an immediate threat.

The program is open for enrollment until subscriptions reach 272 MW or January 1, 2019, whichever comes first.[57] While this does limit the ability for PG&E to provide a 100% renewable option in the long-run, at the start of the CCA this program it provides an opportunity for customers who desire 100% renewable power to remain with PG&E.

## Additional Local Renewables

As noted in Chapter 2, relatively conservative penetrations of locally-sited renewable generation (solar) was included in the quantitative analysis. Even in scenario 3, the most aggressive with respect to renewables, the modeling assumed only 175 MW of in-county solar. Other individuals and studies have placed the potential for solar in the Alameda County at much higher levels. For example, a 2012 study conducted for Pacific Environment, a San Francisco-Based environmental non-governmental agency, placed the "technical potential" for rooftop and parking lot PC at over 3,700 MW.[58] However, it must be noted that technical potential is different than economic or achievable potentials; it represented the absolute ceiling on this kind of PV in the county.

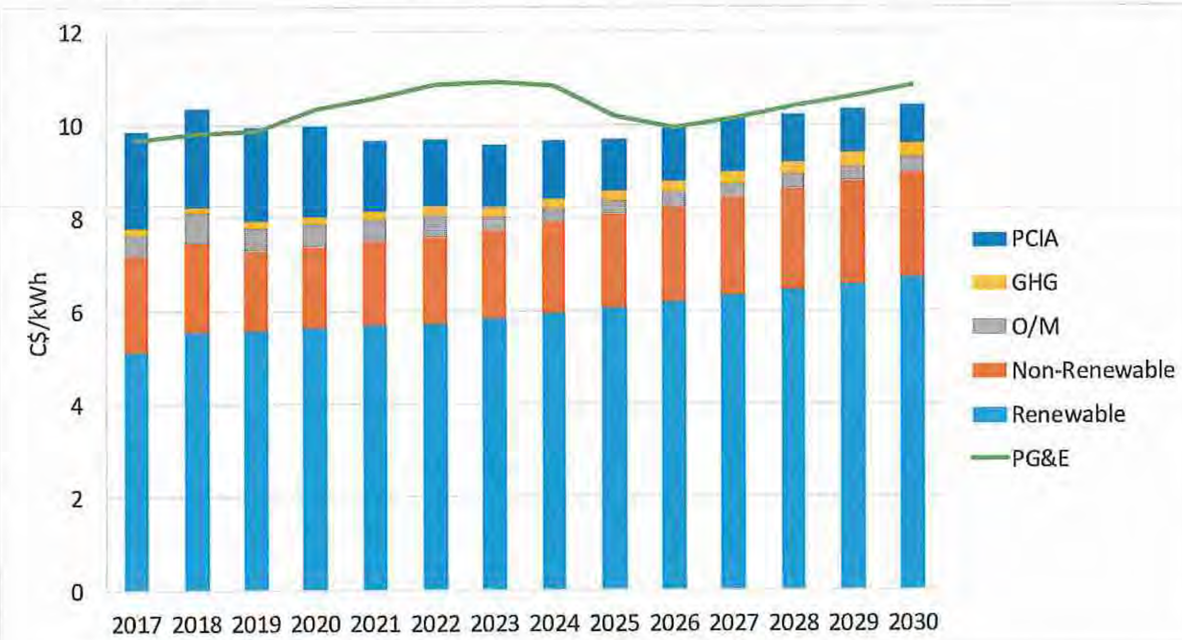
Assuming that greater amounts of this solar potential can in practice be tapped has a number of implications for the results of this study. First, greater local solar will increase CCA costs. As noted in the supply section of Chapter 2, in-county solar costs about 15% more than solar located in lower cost, inland counties, and small solar, such as is quantified in the Pacific Environment

[55] PG&E website http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/RFO/CommunitySolarChoice.page?WT.mc_id=Vanity_communitysolarchoice . Accessed 5/16/2016
[56] California Public Utilities Commission, Decision 15-01-051, p.3
[57] Solar Choice Program FAQs website, https://www.pge.com/en/myhome/saveenergymoney/solar/choice/faq/index.page Accessed, 5/16/2016
[58] Powers, Bill, "Bay Area Smart Energy 2020," March 2012.

report, is typically 55% more costly than central solar. This increased cost will narrow the difference between the rates that the CCA can offer and PG&E. Still, as the analysis has shown, there is significant financial "headroom" to allow for this.

To explore this, we ran Scenario 2 with the assumption that 50% of the renewables were locally sourced. This implies that in 2025, there would be about 925 MW small solar (less than 3MW, including rooftop) and 888 MW large solar in the county (assuming that it can be phased in that quickly). As shown in Figure 30, the margin between the CCA's costs (bars) and the projected PG&E generation rates is much closer than in the standard Scenario 2. This is not unexpected, as local renewables are assumed to be costlier than large-scale ones located in lower-cost areas of the state.

**Figure 30. Scenario 2 with 50% of the Renewables Met Using In-County Generation**




The impacts on the macroeconomics are more complex. Additional local solar would increase local direct jobs by employing more workers to install and maintain solar arrays. On the other hand, the greater driver of jobs, the bill savings from reduced rates, would go down with the increased CCA costs. While this scenario was not explicitly modeled, the results of the three scenarios at were model strongly suggest that total economic activity and jobs would decrease with the inclusion of more local renewables in the CCA's supply portfolio.

# Chapter 8: Conclusions

Overall, a CCA in Alameda County appears favorable. Given current and expected market and regulatory conditions, an Alameda County CCA should be able to offer its residents and business electric rates that are a cent or more per kilowatt-hour less than that available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of renewable energy are assumed in the CCA portfolio (Scenario 3), combined with other negative factors, do PG&E's rates become consistently more favorable than the CCAs.

An Alameda County CCA would also be well positioned to help facilitate greater amounts renewable generation to be installed in the County. While the study assumed a relatively modest amount for its analysis—about 175 MW, other studies suggest that greater amounts are possible. Because the CCA would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would actually occur with a CCA in the County than without it.

The CCA can also reduce the amount greenhouse gases emitted by the County, but only under certain circumstances. Because PG&E's supply portfolio has significant carbon-free generation (large hydroelectric and nuclear generators), the CCA must contract for significant amounts of carbon-fee power above and beyond the required qualifying renewables in order to actually reduce the county's electric carbon footprint. For example, even assuming that the CCA implements a portfolio with 50% qualifying renewables and contracts with carbon-free hydropower 50% of the remaining power (i.e., 50% renewable, 25% hydro, 25% fossil/market), it would only then just barely result in net carbon reductions. However, the extent to which GHG emissions reductions occur is also a function of the amount of hydroelectric power that PG&E is able to use. If hydro output (continues) to be below historic normal levels, then the CCA should be able to achieve GHG savings, (as long as it is also contracting for significant amounts of carbon-free (likely hydroelectric) power). Therefore, if carbon reductions are a high priority for the CCA, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed.

A CCA can also offer positive economic development and employment benefits to the County. At the peak, the CCA would create approximately 2300 new jobs in the region. The large amount for be for construction trades, totaling 440 jobs. What may be surprising is that much for the jobs and economic benefit come from reduced rates; residents, and more importantly businesses, can spend and reinvest their bill savings, and thus generate greater economic impacts.

# Technical Study for Community Choice Aggregation Program in Alameda County

## Addendum:

## Greater Local Renewable Development Scenario

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July 2016

# Addendum: Scenario 4 – Greater Local Renewable Development Scenario

Based on feedback from the Steering Committee, the MRW Team developed a fourth scenario. This scenario is based on Scenario 2: 50% of its load through renewable power starting from 2017, while 50% of its non-renewable load is met through hydro-electricity (i.e., overall 50% qualifying renewable. 25% hydro, 25% fossil or market), but with an increased emphasis on in-county renewable development. For this case, we assumed that one-half of the CCA's total renewable requirement would be met by in-county resources by the year 2030.

This constitutes a very aggressive scenario. The amounts of new in-county renewables assumed are unprecedented, and without a detailed study as to the technical, economic and achievable penetration of local solar, it should be seen as speculative. As such, the results are more uncertain than the prior three scenarios. Nonetheless, it points to the possibility that even greater local economic development benefits and employment if indeed greater local renewable development can be achieved.

## Supply Resources

Figure 1 shows the assumed build-out of new renewable resources under Scenario 4. The local renewable generation starts in 2017, linearly ramping (80 MW per year) up to 50% of the CCA's renewable total by 2030 (900 MW). Consistent with the other scenarios, we considered in-county renewable generation to consist of small- and utility-scale solar.

At the June 1 Steering Committee meeting, a preliminary version of this scenario was presented. This final version differs from that preliminary one in two ways. First, the preliminary version did not assume any phase-in. I.e., 50% local renewables was available at the same rate as CCE participants phased-in. The final version phases in the new local renewables such that 50% is ultimately achieved in 2030. Second, the preliminary version assumed that 50% of the TOTAL load was being met by local renewables, not simply 50% of the renewable component. Thus, the final Scenario 4 contains less renewables and thus lower costs than the preliminary version presented at the Steering Committee Meeting.

**Figure 1. Senario 4 CCA Build-Out**

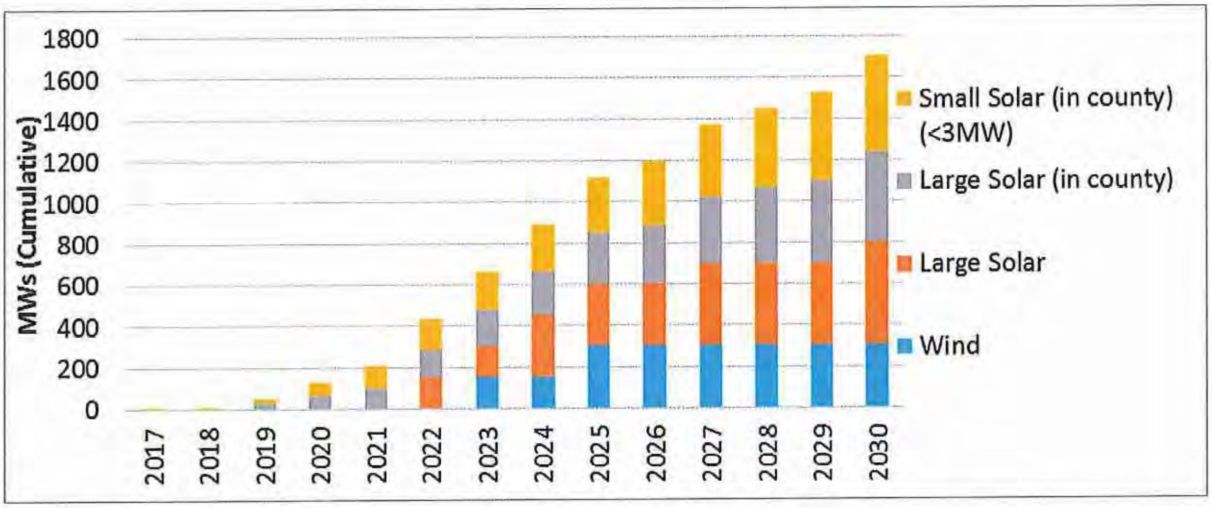
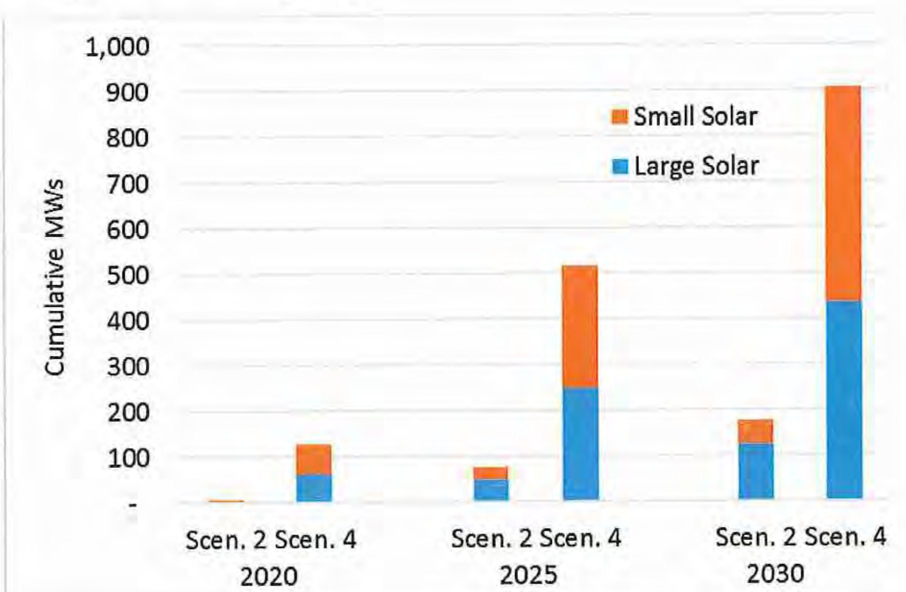



Figure 2 shows the difference on the deployment of the in-county solar generation under Scenarios 2 and 4. Under Scenario 2 the capacity installed increases on average of 15 MW per year up to 180 MW, one-fifth the rate of capacity addition under Scenario 4. Furthermore, under Scenario 4 we assumed a higher fraction of the in-county renewable was met using the small-scale solar. Under Scenario 2, the ratio of small local solar and large local solar is 2:5, while under Scenario 4 the ratio is 1:1.

**Figure 2. Local Capacity Installed for Scenario 2 and Scenario 4**



## Rate Results

Figure 3 summarizes the results for Scenario 4, with the vertical bars representing the Alameda CCA customer rate and the counterpart PG&E generation rate shown as a line. As with the other cases, under the renewable prices assumed in the analysis, the Alameda CCA costs are consistently less than the PG&E rate.

In Scenario 4, the renewable cost is the largest single element of the CCA rate, reflecting the high renewable content of this scenario (50% RPS) and, in special, the important share of in-county renewable generation. Non-renewable generation is the next largest cost component of the rate, followed by the PCIA exit fee.

**Figure 3. Scenario 4 Rate Savings, 2017-2030**

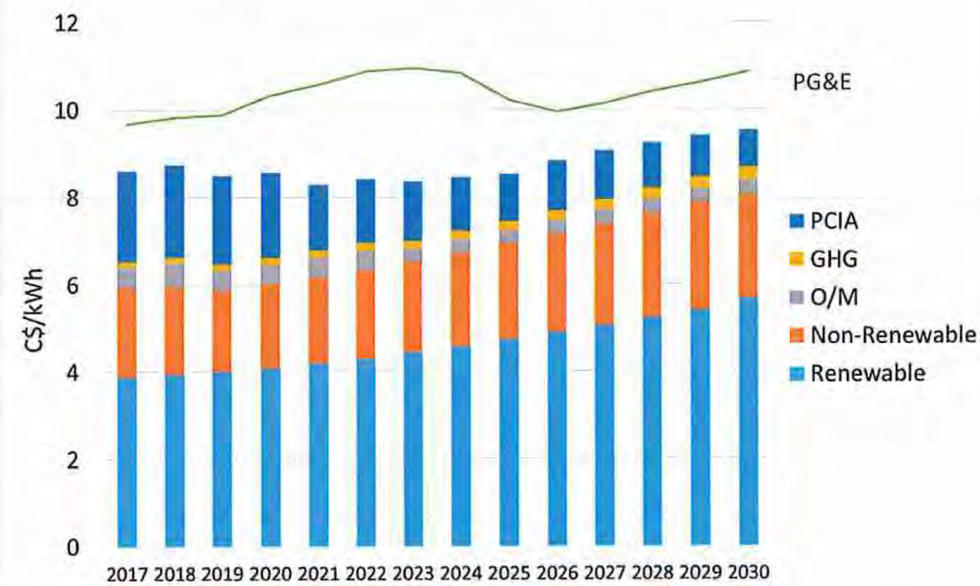



Figure 4 shows the Alameda CCA customer average generation rate for Scenarios 2 and 4. As seen in this figure, the difference on the generation rate between the two scenarios is minimal during the first years of Alameda CCA operations (when local renewable content is still low), but it grows rapidly, ultimately resulting in 6% difference by 2030 (rates for Scenario 4 higher than Scenario 2). This increase is due to the assumed premium for in-county renewable generation, ($20/MWh on average).

**Figure 4. Scenarios 2 and 4 CCA Rates, 2017-2030**

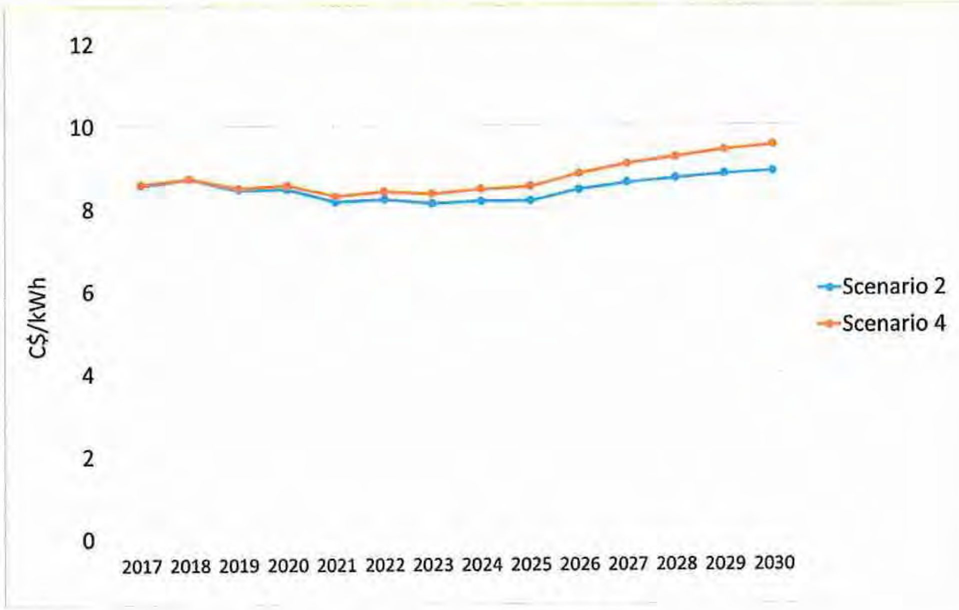



Table 1 below shows the average annual savings for residential customers under Scenario 4. The annual bill for a residential customer on the Alameda CCA program will be for the period 2017-2030 on average 5.7% lower than the same bill on PG&E rates. This is lower than, but close to, bill savings under Scenario 1.

**Table 1. Scenario 4 Savings for Residential CCA Customers**

| Residential | Monthly Consumption (kWh) | Bill with PG&E ($) | Bill with Alameda CCA ($) | Savings ($) | Savings (%) |
|---|---|---|---|---|---|
| 2017 | 650 | 147 | 146 | 1 | 1% |
| 2020 | 650 | 160 | 148 | 12 | 8% |
| 2030 | 650 | 201 | 192 | 9 | 4% |

Because the net generating composition of Scenario 4 is the same as Scenario 2, the greenhouse gas emissions would be approximately the same.

## Macroeconomic Impacts

As Table 2 shows, Scenario 4 would have a 1.7-fold CCA renewable capacity investment compared to Scenario 3, with almost 5-fold local project investment ($3.2 billion of county-sited projects versus $0.67 billion).

**Table 2. Initial Comparison of Proposed CCA Scenarios**

| 2017 to 2030 | Million$ nominal | Million $ nominal DEMAND | | | | | |
|---|---|---|---|---|---|---|---|
| Scenario | Bill Savings* | CCA Renewable Investment | | | CCA Renewable O&M | | PG&E Offset Renew. O&M |
| | | Alameda | Rest of CA | PG&E offset RE invest. Rest ofCA | Alameda | Rest of CA | Alameda |
| 1 | $1,574 | $623 | $1,676 | -$1,946 | $47 | $133 | -$153 |
| 2 | $1,513 | $623 | $2,217 | -$2,446 | $47 | $190 | -$206 |
| 3 | $522 | $674 | $2,514 | -$2,785 | $51 | $200 | -$219 |
| 4 | $521 | $3,222 | $2,217 | -3,325 | $252 | $190 | -$278 |

*Bill savings are net of PCIA and customer out-of-pocket for renewable and energy efficient improvements.

As can be seen from Table 3, the initial local investment that would result from building and operating additional renewable projects in Alameda County between the years 2017 to 2030 represents a very small portion of the County's total expected economic activity, [1] even assuming all of the project costs are directed locally (usually 56% of the project costs would be funneled outside the county due to procurement of equipment from outside the county). By contrast bill savings for Scenarios 1 and 2 provide over three fold the benefits of initial local investment. These bill savings indirectly stimulate the economy and ultimately create jobs.

[1] Forecast to be $3,500 billion (nominal). Source REMI Policy Insight model, Alameda County forecast.

**Table 3**

| | 2017 to 2030 | | | |
|---|---|---|---|---|
| CCA Scenario | Local Capture on RE investments (billion$) | As % of County's Total RE investment | As % of County's Expected Economic Activity | Net Bill Savings (billion$) |
| 1 | $0.42 | 44% | 0.01% | $1.57 |
| 2 | $0.42 | 44% | 0.01% | $1.51 |
| 3 | $0.45 | 45% | 0.01% | $0.52 |
| 4 | $1.86 | 49% | 0.04% | $0.52 |

Table 4 shows high-level results expressed as average annual job changes for the four CCA scenarios. While Scenarios 1 and 2 create nearly identical direct jobs (due to comparable investment in local renewable projects), scenario 1 creates far more TOTAL jobs. This is due to the higher bill savings under scenario 1. Scenario 3 creates a few more direct jobs, but far fewer total jobs, due to decreased bill savings as compared to Scenario 3. The average annual *total* job impact when compared to Scenario 3 increases by a 2.2-fold factor as a result of CCA customers facing the same level of net rate savings despite the amplified level of renewable investment demand associated with the CCA, particularly for local projects.

**Table 4: Average Annual Jobs created in Alameda County by the CCA – Direct and Total Impacts**

| | 2017 – to – 2030 | | County Impacts | |
|---|---|---|---|---|
| CCA Scenario | Local Capture on RE investments (billion$) | Bill Savings (billion$) | Average Annual DIRECT Jobs | Average Annual TOTAL Jobs |
| 1 | $0.42 | $1.57 | 165 | 1322 |
| 2 | $0.42 | $1.51 | 166 | 1286 |
| 3 | $0.45 | $0.52 | 174 | 731 |
| 4 | $1.84 | $0.52 | 579 | 1617 |

Job impacts from building and operating renewable capacity investments in the county account for near 70 percent of annual job creation (compared to the 20 percent in Scenario 1 which had the smallest amount of CCA renewable investments both for the county and elsewhere in the state. It did however have the greatest rate savings to CCA customers). The peak year of impact remains 2023 with the county adding approximately 2,430 jobs.

**Figure 5. County's annual Total Job Impact by source (thousands)**

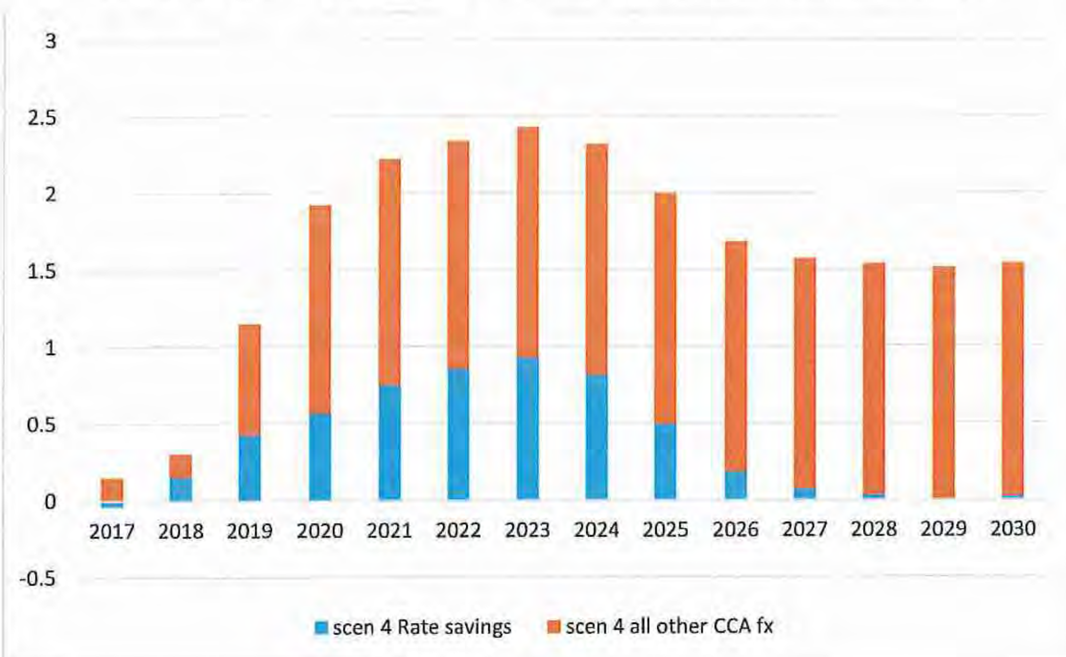



Table 5 addresses the Scenario 4 job impacts occurring (as average annual for 2017 through 2030 and for the 2023 peak year) in the *Construction* sector related to both the direct and total impact stages, juxtaposed against results for the initial scenarios. It also provides an estimate of *Construction* sector job changes on "*covered*" work contracts, using the same approach as done for the three initial scenarios.

**Table 5: Scenario 4 Job Impacts**

| **CCA Scenario** | Avg. Annual Direct Jobs- **all sectors** | Avg. Annual Direct Jobs- **Construction sector** | **...that are associated with CBA** | Peak Year Direct Jobs- **Construction sector** | **...that are associated with CBA** |
|---|---|---|---|---|---|
| 1 | 165 | 80 | *16* | 136 | 27 |
| 2 | 166 | 81 | *16* | 137 | 27 |
| 3 | 174 | 86 | *17* | 154 | 31 |
| 4 | 574 | 318 | 64 | 359 | 72 |
| **CCA Scenario** | Avg. Annual *Total* Jobs- **all sectors** | Avg. Annual *Total* Jobs- **Construction sector** | **...that are associated with CBA** | Peak Year Total Jobs- **Construction sector** | **...that are associated with CBA** |
| 1 | 1343 | 235 | *47* | 440 | 88 |
| 2 | 1308 | 231 | *46* | 432 | 86 |
| 3 | 752 | 160 | *32* | 326 | 65 |
| 4 | 1617 | 455 | 91 | 634 | 127 |

# Technical Study for Community Choice Aggregation Program in Alameda County

## Appendices

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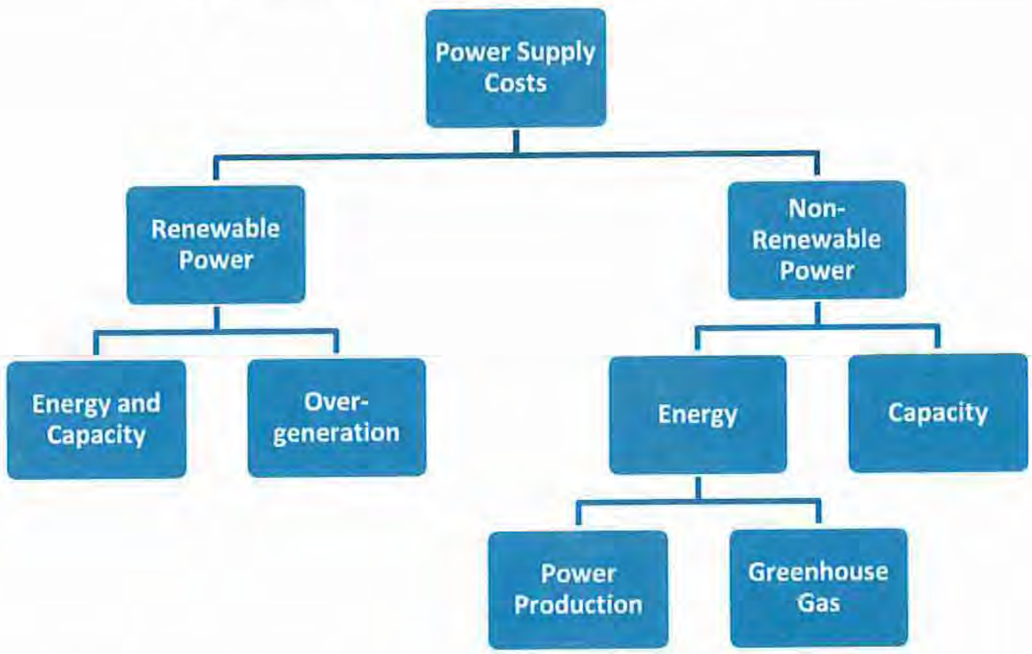
# Appendix A. Loads and Forecast

| 2014 Load (MWh) | Residential | Commercial | Industrial | Public | Street lights + Pumping |
|---|---|---|---|---|---|
| OAKLAND | 660,782 | 741,932 | 415,045 | 167,285 | 20,345 |
| FREMONT | 392,214 | 676,908 | 185,178 | 47,987 | 4,427 |
| HAYWARD | 240,909 | 444,599 | 71,270 | 30,672 | 25,598 |
| BERKELEY | 159,531 | 206,825 | 86,752 | 227,612 | 3,734 |
| PLEASANTON | 185,564 | 272,979 | 42,262 | 22,162 | 6,147 |
| SAN LEANDRO | 155,124 | 228,047 | 91,569 | 38,709 | 3,381 |
| UNINCORPORATED | 271,869 | 123,148 | 82,804 | 31,308 | 4,788 |
| LIVERMORE | 211,533 | 236,038 | 26,615 | 23,171 | 862 |
| UNION CITY | 114,258 | 175,482 | 6,194 | 54,684 | 5,401 |
| DUBLIN | 113,425 | 129,981 | 26,134 | 25,465 | 2,214 |
| NEWARK | 75,030 | 144,879 | 21,720 | 15,670 | 1,421 |
| EMERYVILLE | 21,608 | 132,815 | 44,507 | 3,637 | 1,024 |
| ALBANY | 23,494 | 13,997 | 15,602 | 2,855 | 1,778 |
| PIEDMONT | 27,774 | 1,622 | 0 | 3,044 | 328 |

# Appendix B. Power Supply Cost

MRW has developed a bottoms-up calculation of Alameda CCA's power supply costs, separately forecasting the cost of each power supply element. These elements are renewable energy, non-renewable energy (including power production costs and greenhouse gas costs), resource adequacy (RA) capacity (both renewable and non-renewable supplies) and related costs (e.g., CAISO expenses and broker fees).[1] Figure 1 illustrates the components of Alameda CCA's expected supply costs.

**Figure 1: Power Supply Cost Forecast**




## Renewable Power Cost Forecast

MRW developed a forecast of renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and Community Choice Aggregation (CCA) entities in 2015 and early 2016, finding an average price of $52 per MWh for these contracts.[2]

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[1] MRW included a 5.5% adder in the power supply cost for CAISO costs (ancillary services, etc.), and a 5% premium for contracted supplies to reflect broker fees and similar expenses.

[2] MRW relied exclusively on prices from municipal utilities and CCAs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in California Energy Markets, an

To forecast the future price of renewable purchases, MRW considered a number of factors:

- Researchers from the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL) developed a set of forecasts of utility-scale solar costs based on market data and preliminary data from other research efforts.[3] Their base case forecast predicts a 3.8% annual decline in utility-scale solar capital costs on a nominal basis, from $1,932/kW-DC in 2016 to $1,652/kW-DC in 2020, with costs then remaining roughly constant in nominal dollars through 2030.[4] Additional scenarios predict even steeper price declines, with the most aggressive scenario predicting an 11% annual nominal decline through 2020, with increases at the rate of inflation after that.
- The federal Investment Tax Credit (ITC), which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain.[5] The federal Production Tax Credit, which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.[6] The loss of these credits would put upward pressure on prices.
- NREL and LBNL researchers predicted in 2015 that the cost increase associated with an ITC reduction would be roughly offset by other solar cost reductions even if the full reduction to 10% were to be implemented by 2018, rather than spread out through 2022 as is currently planned.[7]
- The production tax credit has been extended six times from 2000-2014,[8] and the solar ITC has been extended three times since 2007.[9] Further tax credit extensions are therefore plausible.
- The major California investor-owned utilities have significantly slowed their renewable procurement because lower-than-expected customer sales and higher-than-expected contracting success rates have led to procurement in excess of the RPS requirements

independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

[3] National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 16. http://www.nrel.gov/docs/fy16osti/65014.pdf

[4] Ibid. Costs converted to nominal dollars using the inflation forecast used throughout the rate forecast model (U.S. EIA's forecast of the Gross Domestic Product Implicit Price Deflator).

[5] U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

[6] U.S. Department of Energy. Electricity Production Tax Credit (PTC). http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[7] National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 28.

[8] Union of Concerned Scientists. Production Tax Credit for Renewable Energy. http://www.ucsusa.org/clean_energy/smart-energy-solutions/increase-renewables/production-tax-credit-for.html

[9] Solar Energy Industries Association. Solar Investment Tax Credit. http://www.seia.org/policy/finance-tax/solar-investment-tax-credit; and U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

through 2020. When the utilities start ramping their procurement back up to meet the 50%-by-2030 RPS requirement, the supply-demand balance in the market may shift, resulting in higher-than-expected prices unless an increase in suppliers and development opportunities matches the increase in demand.

Given the potential upward price pressures from tax credits that are currently expected to expire and from higher demand for renewable power to meet the 50%-by-2030 requirement and the potential downward price pressures from falling renewable development costs, the possibility for lower cost procurement through the use of RECs, and the possibility that the expiry of the tax credits will be further delayed, it is unclear whether renewable prices will continue to fall (as NREL, LBNL, and others are predicting) or will start to stabilize and rise. MRW has addressed this uncertainty by considering two scenarios. In the base renewable cost forecast, MRW used the $52 per MWh average price of recent municipal utility and CCA wind and solar contracts as the price through 2022 (in nominal dollars), increasing the price with inflation in subsequent years. This results in a price of $59 per MWh in 2030. In the high renewable cost scenario, MRW increased the base case renewable prices to account for the expected expiration of the tax credits, resulting in a price of $77 per MWh in 2030. These scenarios provide a reasonable window of renewable price projections based on current market conditions and analysts' expectations.

MRW used these same renewable prices to calculate PG&E's renewable power costs. However, as described in Appendix B in the PG&E forecast, these renewable energy prices are used only for incremental power that is needed above PG&E's existing RPS contracts. For Alameda CCA, these prices are used as the basis for its entire RPS-eligible portfolio.

MRW additionally included a premium for the portion of Alameda CCA's RPS portfolio assumed in each scenario to be located in Alameda County. While solar energy is anticipated to provide the largest share of incremental supply located in-county, the solar resource in Alameda is not as strong as in the areas being developed to supply the contracts discussed above. As a result, the cost of solar generation in Alameda is expected to be higher than the contract prices we have assumed for non-Alameda supplies. Additionally, there are economies of scale in solar power development that mean small, local solar projects will cost more than the utility-scale projects upon which the average contract prices were derived. Based on information provided in the CPUC's current RPS calculator, which provides cost estimates for renewable energy projects located around California, large solar projects in Alameda are expected to have a 15% premium over projects in areas with the best solar resource. Generation from smaller projects (<3 MW) in Alameda are assumed to cost 55% more than the base contract price assumed in our forecast.

Given the high levels of renewable energy assumed in each of the scenarios, and the variable patterns of renewable energy production, there are likely to be periods during which the renewable energy projects with which the Alameda CCA has contracted are producing more than its customers require. [10] This excess supply must be managed by the Alameda CCA and will likely add to its overall supply costs. For the purpose of this assessment, MRW assumed that the excess renewable supply would be sold at 10% of the cost of additional renewable purchases

[10] The annual oversupply is equal to the sum of positive hourly differences between RPS generation and load.

made at other times to make up for the annual shortfall.[11] The cost of managing excess renewable energy supply could be reduced through the use of unbundled RECs. For example, in hours when the CCA is long on renewable energy, it could simply resell the energy in the spot market and keep the REC rather than selling the bundled REC at a discount in one hour when it has excess supply and purchasing a bundled REC in another hour.

## Non-Renewable Energy Cost Forecast

MRW separated the costs of non-renewable energy generation into two components: power production costs and greenhouse gas costs. The forecast methodologies for these cost elements, described below, are consistent with the forecast methodologies used for these cost elements in the PG&E rate forecast.

Since natural gas generation is typically on the margin in the California wholesale power market, power production costs for market power are driven by the price for natural gas. MRW forecasted natural gas prices based on current NYMEX market futures prices for natural gas, projected long-term natural gas prices in the EIA's *2015 Annual Energy Outlook*,[12] and PG&E's tariffed natural gas transportation rates.[13] MRW used a standard methodology of multiplying the natural gas price by the expected heat rate for a gas-fired unit and adding in variable operations and maintenance costs to calculate total power production costs.

In addition to power production costs, the cost of energy generated in or delivered to California also includes the cost of greenhouse gas allowances that, per the state's cap-and-trade program, must be procured to cover the greenhouse gases emitted by the energy generation. MRW developed a forecast of the prices for these allowances based on the results of the California Air Resources Board's (ARB's) auctions for Vintage 2015 allowances,[14] increased annually in proportion to the auction floor price increases stipulated by the ARB's cap-and-trade regulation.[15] MRW estimated the emissions rate of Alameda CCA non-renewable power supply based on an estimated heat rate for market power multiplied by the emissions factor for natural gas combustion.[16]

## Capacity Cost Forecast for Non-Renewable Power

[11] This is because it is likely that other potential buyers of renewable energy at times when Alameda has excess supply will also have lower need for additional renewable energy.

[12] U.S. Energy Information Administration. "2015 Annual Energy Outlook," Table 13.

[13] Pacific Gas & Electric, Burnertip Transporation Charges. Tariff G-EG, Advice Letter 3664-G, January 2016 and Tariff G-SUR, Advice Letter 3699-G, April 2016.

[14] Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

[15] California Code of Regulations, Title 17, Article 5, Section 95911.

[16] U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

To estimate Alameda CCA's capacity requirements, MRW developed a forecast of Alameda CCA's peak demand in each year and subtracted the net qualifying capacity credits provided by Alameda CCA's renewable power purchases. This is appropriate because the renewable energy prices used in this analysis reflect prices for contracts that supply both energy and capacity. If Alameda CCA purchases renewable energy via energy-only contracts, Alameda CCA's need for capacity will be greater than forecasted here, but these higher costs will be fully offset by the lower costs for the renewable energy.

MRW estimated current peak demand for Alameda CCA's load using the 2013-2014 monthly bills for all the current PG&E clients in Alameda county[17] and PG&E's class-average load profiles. We forecasted changes to this peak demand based on the California Energy Commission's forecast of changes to peak demand in PG&E's planning area.[18] We calculated capacity requirements as 115% of the expected peak demand in order to include sufficient capacity to fulfill resource adequacy requirements. We applied a consistent methodology to obtain the peak demand growth rates and capacity requirements for PG&E.

To estimate the cost of Alameda CCA's capacity needs, MRW priced capacity purchases at the median price of recent Resource Adequacy purchases, escalated with inflation.[19]

[17] Monthly bills corresponding to 2013 and 2014 for all the clients in Alameda county provided by PG&E.

[18] California Energy Commission. Demand Forecast. PG&E Forecast Zone Results Mid Demand Case, Sales Forecast, Central Valley Region. December 14, 2015.

[19] CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

# Appendix C. Forecast of PG&E's Generation Rates

MRW developed a forecast of PG&E's generation rates for comparison with the rates that Alameda CCA will need to charge to cover its costs of service. MRW developed the forecast for the years 2017-2030 using publicly available inputs, including cost and procurement data from PG&E, market price data, and data from California state regulatory agencies and the U.S. Energy Information Administration. The structure of the rate forecast model and the basic assumptions and inputs used are described below.

## Generation Charges

PG&E's generation costs fall into four broad categories: (1) renewable generation costs, (2) fixed costs of non-renewable utility-owned generation, (3) fuel and purchased power costs for non-renewable generation, and (4) capacity costs. Each of these categories is evaluated separately in the rate forecast model, and underlying these forecasts is a forecast of PG&E's generation sales.

## Sales Forecast

PG&E's generation cost forecast is driven in large part by the amount of generation that PG&E will need to obtain to meet customer demand. To forecast PG&E's electricity sales, MRW started with the 2016-2030 sales forecast that PG&E provided in its January 2016 Renewable Energy Procurement Plan ("RPS Plan") filing with the CPUC.[20] This forecast predicts 4% annual sales reductions through 2020 and anemic sales growth of 0.2% per year from 2020-2025, before increasing to close to 1% per year from 2025-2030.[21]

## Renewable Generation

The starting point for MRW's analysis is PG&E's "RPS Plan," in which PG&E discusses its plan for meeting California's Renewable Portfolio Standard (RPS) targets and provides the annual amount and cost of renewable generation currently under contract through 2030. PG&E's RPS Plan shows that PG&E's current renewable procurement is in excess of the RPS requirement in each year through 2022. After 2022, PG&E's renewable generation from current contracts falls below the RPS requirements, but PG&E is projected to have enough banked Renewable Energy Credits (RECs) from excess renewable procurement in prior years to meet the RPS requirements until 2025.

MRW adopted PG&E's RPS Plan forecast of the amount and cost of renewable generation that is currently under contract. For the period starting in 2026 when PG&E's RPS Plan shows a need

[20] Pacific Gas & Electric. *Renewables Portfolio Standard 2015 Renewable Energy Procurement Plan (Final Version)*. January 14, 2016. Appendix D.

[21] The near-term decline in sales in PG&E's forecast is likely attributable to the growth in CCA, in which a municipality procures electric power on behalf of its constituents instead of having them purchase their power from PG&E. While customers in the jurisdictions of these municipalities have the option to opt-out of CCA and to continue to procure power from PG&E, so far, most CCA-eligible customers have not elected for this option. CCA customers continue to procure electricity delivery services from PG&E; it is only generation services that they obtain through the CCA.

for incremental renewable procurement to meet RPS requirements, MRW added in the necessary renewable generation to meet current statutory requirements (i.e., 33% of procurement in 2020, increasing to 50% of procurement in 2030).[22] To project PG&E's cost of this incremental renewable generation, MRW used the same renewable prices used for Alameda CCA's renewable power cost forecast (see 0).

### Fixed Cost of Non-Renewable Utility-Owned Generation

PG&E's rates include payment for the fixed costs of the PG&E-owned non-renewable generation facilities, which are primarily natural gas, nuclear, and hydroelectric power plants. Because these costs are not tied to the volume of electricity that PG&E sells, their annual escalation is not driven by the price of fuel and other variable inputs. Instead, they escalate at a rate that stems from a combination of cost increases and depreciation reductions. These escalation rates are determined in General Rate Case (GRC) proceedings, which occur roughly every three years.

As a starting point for the forecast, MRW used the adopted 2016 fixed costs for these facilities.[23] For the period between 2017 and 2019, MRW estimated escalation rates based on PG&E's proposal in its 2017 GRC application,[24] estimating in the base case that PG&E would receive 2/3 of its requested GRC increases and in an alternate scenario that PG&E would receive 50% of its requested increases in order to evaluate a window of potential GRC outcomes. For subsequent years, MRW estimated in the base case that PG&E's generation fixed costs would increase by the 6.2% annual average growth rate approved and implemented for these cost over the last ten years. In the alternate scenarios, we instead applied a 4.9% annual average growth rate, calculated as 20% discount off the base case growth rate.[25] These escalation rates are in nominal dollars (i.e., some of the escalation is accounted for by inflation).

[22] MRW additionally allowed for the purchase of additional renewable generation when renewable prices are below market prices, subject to some purchase limits, including a 50% cap on renewable generation relative to the entire generation portfolio. This leads to additional renewable purchases from 2027-2029 in the Low Renewable Price scenario. Starting in 2030, the RPS requirement is 50%, and no additional renewable purchases are allowed, per the rules of the model, in order to maintain grid reliability.

[23] Pacific Gas & Electric. Annual Electric True-Ups for 2016. Advice Letter 4696 E-A. January 4, 2016. Table 2.

[24] Pacific Gas & Electric 2017 GRC Request, A.15-09-001, Exhibit PG&E-10, Tables E-3 and E-4.

[25] Historic growth rates calculated from Pacific Gas & Electric Advice Letters 2706-E-A, AL 3773-E, 4459-E, 4647-E, and 4755-E. New power plant costs were excluded from these calculations since costs of new plants are offset, at least in part, by a reduction in fuel and purchased power costs.

**Table 1: PG&E's Generation Fixed Costs, 2011-2016[26]**
(Nominal $ Million)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| Generation Fixed Costs | 1,400 | 1,530 | 1,550 | 1,710 | 1,860 | 1,840 |
| Annual Cost Increase | | 9% | 1% | 10% | 9% | -1% |

MRW made adjustments to this GRC forecast to account for the likely retirement of the Diablo Canyon nuclear units at the end of the units' current licenses in 2024 and 2025. As of April 2015, PG&E was undecided as to whether it would pursue a license extension for the Diablo Canyon units.[27] There is ample reason for this uncertainty. For example, the CPUC has stated that PG&E will be required to present a thorough assessment of the cost-effectiveness of relicensing, including a number of studies exploring reliability, security, and safety implications;[28] PG&E will also be required to undertake a massive cooling system modification project before operating the nuclear plant past 2024 (per state regulations implementing the Federal Clean Water Act, Section 316(b));[29] an independent panel of peer reviewers to recent federal- and state-required PG&E seismic studies has unresolved concerns over these studies;[30] and the U.S. Nuclear Regulatory Commission is requiring PG&E to conduct additional earthquake hazard analysis because initial post-Fukushima studies showed a hazard level above the original design basis for the plant.[31] Given the uncertainties surrounding the continued operation of the plant, MRW assumed in the base case that the Diablo Canyon units would be shut down at the end of their current licenses.

In an alternate relicensing scenario, MRW included costs for the cooling system modification project that would be required.[32] To estimate annual ratepayer costs from this project, we conservatively used PG&E's $4,489 million cost estimate for a closed cycle cooling system,[33]

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26 2011-2013: CPUC Decision 11-05-018, pages 2 and 15; and 2014-2016: CPUC Decision 14-08-032, Appendix C, Table 1 and Appendix D, Table 1.

27 California Energy Commission. "2015 Integrated Energy Policy Report," February 24, 2016 ("2015 IEPR"), pages 177-178. http://www.energy.ca.gov/2015_energypolicy/

28 2015 IEPR, page 178.

29 California State Water Resources Control Board. "Fact Sheet: Once-Through Cooling Policy Protects Marine Life And Insures Electric Grid Reliability," http://www.swrcb.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling.pdf

30 2015 IEPR, pages 180-183.

31 2015 IEPR, page 184.

32 California State Water Resources Control Board. "Fact Sheet: Once-Through Cooling Policy Protects Marine Life And Insures Electric Grid Reliability,"

33 Subcommittee Comments on Bechtel's Assessment of Alternatives to Once-Through-Cooling for Diablo Canyon Power Plant. November 18, 2014, page 10.

depreciated over a 20-year period. MRW did not include costs for the CPUC-required cost-effectiveness study or for the investments that, based on the finding of the study, may be required to shore up the safety and reliability of the plant and its spent fuel management program because these costs are not well defined at this point.

## Fuel and Purchased Power Costs for Non-Renewable Generation

Each spring, PG&E files a forecast with the CPUC of its fuel and purchased power costs for the upcoming year in its "ERRA" filing, which PG&E updates and finalizes in November. MRW relied on PG&E's November 2015 ERRA testimony,[34] adjusted to remove renewable generation costs, as the starting point for the forecast of fuel and purchased power costs for PG&E's non-renewable generation.

To escalate these costs through the forecast period, MRW forecasted changes to natural gas prices and greenhouse gas cap-and-trade program compliance costs, which are the major drivers of change to these costs. The natural gas price forecast is based on current NYMEX market futures prices for natural gas, forecasted natural gas prices in the U.S. EIA's *2015 Annual Energy Outlook*, and PG&E's tariffed natural gas transportation rates. This forecast is the same forecast used in the forecast of Alameda CCA's wholesale power costs (see 0).

Cap-and-trade program compliance costs are estimated based on (1) PG&E's forecast of carbon dioxide emissions in 2016;[35] (2) a forecast of PG&E's fossil generation supply, developed by subtracting expected renewable, hydroelectric, and nuclear generation from PG&E's projected wholesale power requirement; and (3) a forecast of greenhouse gas allowance prices. The greenhouse gas allowance price forecast is the same as used in the forecast of Alameda CCA wholesale power costs and is based on the results of the California Air Resources Board's (ARB's) most recent allowance auctions, increased annually in proportion to the auction floor price increases stipulated by the ARB's cap-and-trade regulation (see 0).

The MRW rate model calculates total fuel and purchased power costs by escalating natural gas prices based on the natural gas price forecast described above, escalating nuclear fuel prices based on the EIA forecast of fuel costs for nuclear plants, escalating water costs for hydroelectric projects and the capacity costs of power purchase contracts with inflation, and pricing market power at the same market power price used for Alameda CCA's purchases. The model then sums the cost for each of these resources and adds in projected cap-and-trade compliance costs to this total cost.

[34] PG&E Update To Prepared 2016 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.15-06-001 on Nov 5, 2015, pages 14 and 24.

[35] PG&E Update To Prepared 2016 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.15-06-001 on Nov 5, 2015, Table 11-2.

## Capacity Costs

PG&E must procure capacity to meet 115% of its anticipated peak demand in order to fulfill its resource adequacy requirement. PG&E's own power plants can be used to meet this requirement, as can power plants with which PG&E has contracts.

To estimate PG&E's capacity requirements, MRW started with the Capacity Supply Plan that PG&E submitted to the California Energy Commission in 2015,[36] which forecasts PG&E's peak demand and existing capacity resources for each of the years 2013-2024. With limited exception,[37] MRW used PG&E's data where publicly available and extended the forecasts to 2030. In extending these forecasts, we used assumptions that are consistent with those used in our assessments of energy sales and costs, including load growth escalation and the projected retirement of PG&E's nuclear plant. We also added in anticipated capacity from new renewable procurement and from new energy storage and adjusted the calculation to account for the portion of Resource Adequacy credits that is allocated to non-bundled customers.

As with the Alameda CCA's capacity cost forecast, MRW priced capacity at the median price of recent Resource Adequacy capacity sales, escalated with inflation.[38]

## Rate Development

Following the methodologies described above, MRW developed a forecast of PG&E's generation revenue requirement and divided these expenses by the expected PG&E sales in order to obtain a forecast of the system-average generation rate. We calculated annual escalators based on these system-average rates and applied them to the generation rates that are currently in effect for each customer class.[39]

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36 California Energy Commission, Energy Almanac, Utility Capacity Supply Plans from 2015. September 4, 2015

37 The main exception is that we increased energy efficiency and demand response growth to comply with SB 350 requirements to double energy efficiency by 2030 and the anticipated continuation of CPUC demand response initiatives.

38 CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

39 PG&E Advice Letter AL-4805-E, effective March 24, 2016.

# Appendix D. Detailed Pro Forma and CCA Rates

| Case-Legend | |
|---|---|
| Base | B |
| High natural gas price | G |
| High PCIA | P |
| Diablo Canyon relicensed | D |
| High renewable prices | R |
| Low PG&E portfolio costs | L |
| Stress Scenario | S |

| Scenario | Case | Rates ($/MWh) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | B | CCA generation | 6.0 | 6.2 | 6.1 | 6.2 | 6.4 | 6.6 | 6.6 | 6.8 | 7.0 | 7.2 | 7.4 | 7.7 | 7.9 | 8.1 |
| 1 | B | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.2 | 1.1 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 1 | B | CCA Reserve Fund | 0.9 | 0.5 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1 | B | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 10.8 | 10.2 | 9.9 | 10.1 | 10.4 | 10.6 | 10.9 |
| 1 | G | CCA generation | 6.8 | 7.2 | 7.3 | 7.7 | 7.9 | 8.0 | 8.1 | 8.2 | 8.4 | 8.7 | 8.9 | 9.0 | 9.2 | 9.4 |
| 1 | G | Exit fees | 2.0 | 2.0 | 1.9 | 1.9 | 1.5 | 1.5 | 1.5 | 1.5 | 1.3 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 1 | G | CCA Reserve Fund | 1.0 | 0.6 | 0.4 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1 | G | PG&E generation | 9.9 | 10.2 | 10.2 | 10.7 | 10.9 | 11.1 | 11.2 | 10.9 | 10.6 | 10.7 | 10.9 | 11.2 | 11.4 | 11.7 |
| 1 | P | CCA generation | 6.0 | 6.2 | 6.1 | 6.2 | 6.4 | 6.6 | 6.6 | 6.8 | 7.0 | 7.2 | 7.4 | 7.7 | 7.9 | 8.1 |
| 1 | P | Exit fees | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 |
| 1 | P | CCA Reserve Fund | 0.9 | 0.5 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1 | P | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 10.8 | 10.2 | 9.9 | 10.1 | 10.4 | 10.6 | 10.9 |
| 1 | D | CCA generation | 6.0 | 6.2 | 6.1 | 6.2 | 6.4 | 6.6 | 6.6 | 6.8 | 7.0 | 7.2 | 7.4 | 7.7 | 7.9 | 8.1 |
| 1 | D | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.3 | 1.2 | 1.3 | 1.2 | 1.1 | 1.0 | 0.9 |
| 1 | D | CCA Reserve Fund | 0.9 | 0.5 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1 | D | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 11.2 | 12.8 | 13.1 | 13.3 | 13.7 | 14.0 | 14.3 |
| 1 | R | CCA generation | 6.0 | 6.2 | 6.2 | 6.4 | 6.8 | 7.0 | 7.2 | 7.5 | 7.7 | 8.0 | 8.2 | 8.5 | 8.8 | 9.0 |
| 1 | R | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.4 | 1.3 | 1.1 | 0.9 | 1.0 | 1.0 | 0.9 | 0.8 | 0.7 |
| 1 | R | CCA Reserve Fund | 0.9 | 0.5 | 0.3 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1 | R | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 11.0 | 10.8 | 10.2 | 10.2 | 10.5 | 10.8 | 11.0 | 11.3 |
| 1 | L | CCA generation | 6.0 | 6.2 | 6.1 | 6.2 | 6.4 | 6.6 | 6.6 | 6.8 | 7.0 | 7.2 | 7.4 | 7.7 | 7.9 | 8.1 |
| 1 | L | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.2 | 1.1 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 1 | L | CCA Reserve Fund | 0.6 | 0.6 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1 | L | PG&E generation | 8.7 | 8.8 | 8.9 | 9.3 | 9.5 | 9.8 | 9.8 | 9.7 | 9.2 | 8.9 | 9.1 | 9.4 | 9.6 | 9.8 |
| 1 | S | CCA generation | 6.8 | 7.3 | 7.4 | 7.8 | 8.2 | 8.4 | 8.7 | 8.9 | 9.1 | 9.5 | 9.7 | 9.9 | 10.1 | 10.4 |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | S | Exit fees | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| 1 | S | CCA Reserve Fund | 0.1 | -0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1 | S | PG&E generation | 9.0 | 9.2 | 9.3 | 9.7 | 9.9 | 10.3 | 10.4 | 10.4 | 10.1 | 10.1 | 10.3 | 10.5 | 10.7 | 10.9 |
| 2 | B | CCA generation | 6.5 | 6.6 | 6.4 | 6.5 | 6.7 | 6.8 | 6.8 | 6.9 | 7.1 | 7.3 | 7.5 | 7.7 | 7.9 | 8.1 |
| 2 | B | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.2 | 1.1 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 2 | B | CCA Reserve Fund | 1.0 | 0.5 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2 | B | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 10.8 | 10.2 | 9.9 | 10.1 | 10.4 | 10.6 | 10.9 |
| 2 | G | CCA generation | 7.1 | 7.4 | 7.3 | 7.6 | 7.8 | 7.9 | 7.9 | 8.1 | 8.3 | 8.6 | 8.8 | 9.0 | 9.2 | 9.4 |
| 2 | G | Exit fees | 2.0 | 2.0 | 1.9 | 1.9 | 1.5 | 1.5 | 1.5 | 1.5 | 1.3 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 2 | G | CCA Reserve Fund | 0.9 | 0.7 | 0.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2 | G | PG&E generation | 9.9 | 10.2 | 10.2 | 10.7 | 10.9 | 11.1 | 11.2 | 10.9 | 10.6 | 10.7 | 10.9 | 11.2 | 11.4 | 11.7 |
| 2 | P | CCA generation | 6.5 | 6.6 | 6.4 | 6.5 | 6.7 | 6.8 | 6.8 | 6.9 | 7.1 | 7.3 | 7.5 | 7.7 | 7.9 | 8.1 |
| 2 | P | Exit fees | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 |
| 2 | P | CCA Reserve Fund | 1.0 | 0.5 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2 | P | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 10.8 | 10.2 | 9.9 | 10.1 | 10.4 | 10.6 | 10.9 |
| 2 | D | CCA generation | 6.5 | 6.6 | 6.4 | 6.5 | 6.7 | 6.8 | 6.8 | 6.9 | 7.1 | 7.3 | 7.5 | 7.7 | 7.9 | 8.1 |
| 2 | D | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.3 | 1.2 | 1.3 | 1.2 | 1.1 | 1.0 | 0.9 |
| 2 | D | CCA Reserve Fund | 1.0 | 0.5 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2 | D | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 11.2 | 12.8 | 13.1 | 13.3 | 13.7 | 14.0 | 14.3 |
| 2 | R | CCA generation | 6.5 | 6.7 | 6.6 | 6.8 | 7.2 | 7.4 | 7.6 | 7.8 | 8.0 | 8.2 | 8.4 | 8.6 | 8.8 | 9.0 |
| 2 | R | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.4 | 1.3 | 1.1 | 0.9 | 1.0 | 1.0 | 0.9 | 0.8 | 0.7 |
| 2 | R | CCA Reserve Fund | 1.0 | 0.5 | 0.3 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2 | R | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 11.0 | 10.8 | 10.2 | 10.2 | 10.5 | 10.8 | 11.0 | 11.3 |
| 2 | L | CCA generation | 6.5 | 6.6 | 6.4 | 6.5 | 6.7 | 6.8 | 6.8 | 6.9 | 7.1 | 7.3 | 7.5 | 7.7 | 7.9 | 8.1 |
| 2 | L | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.2 | 1.1 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 2 | L | CCA Reserve Fund | 0.1 | 0.9 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2 | L | PG&E generation | 8.7 | 8.8 | 8.9 | 9.3 | 9.5 | 9.8 | 9.8 | 9.7 | 9.2 | 8.9 | 9.1 | 9.4 | 9.6 | 9.8 |
| 2 | S | CCA generation | 7.1 | 7.4 | 7.5 | 7.9 | 8.3 | 8.5 | 8.8 | 9.0 | 9.2 | 9.5 | 9.7 | 9.9 | 10.1 | 10.4 |
| 2 | S | Exit fees | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| 2 | S | CCA Reserve Fund | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2 | S | PG&E generation | 9.0 | 9.2 | 9.3 | 9.7 | 9.9 | 10.3 | 10.4 | 10.4 | 10.1 | 10.1 | 10.3 | 10.5 | 10.7 | 10.9 |
| 3 | B | CCA generation | 6.5 | 6.9 | 7.0 | 7.4 | 7.9 | 8.0 | 8.0 | 8.2 | 8.3 | 8.5 | 8.7 | 8.9 | 9.1 | 9.2 |
| 3 | B | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.2 | 1.1 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 3 | B | CCA Reserve Fund | 1.0 | 0.5 | 0.4 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 3 | B | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 10.8 | 10.2 | 9.9 | 10.1 | 10.4 | 10.6 | 10.9 |
| 3 | G | CCA generation | 7.1 | 7.5 | 7.6 | 8.0 | 8.4 | 8.5 | 8.5 | 8.6 | 8.8 | 9.0 | 9.2 | 9.4 | 9.6 | 9.8 |
| 3 | G | Exit fees | 2.0 | 2.0 | 1.9 | 1.9 | 1.5 | 1.5 | 1.5 | 1.5 | 1.3 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 3 | G | CCA Reserve Fund | 0.9 | 0.7 | 0.4 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 3 | G | PG&E generation | 9.9 | 10.2 | 10.2 | 10.7 | 10.9 | 11.1 | 11.2 | 10.9 | 10.6 | 10.7 | 10.9 | 11.2 | 11.4 | 11.7 |
| 3 | P | CCA generation | 6.5 | 6.9 | 7.0 | 7.4 | 7.9 | 8.0 | 8.0 | 8.2 | 8.3 | 8.5 | 8.7 | 8.9 | 9.1 | 9.2 |
| 3 | P | Exit fees | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | P | CCA Reserve Fund | 1.0 | 0.5 | 0.4 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | -0.2 | -0.7 | -0.3 | 0.0 | 0.0 | 0.0 |
| 3 | P | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 10.8 | 10.2 | 9.9 | 10.1 | 10.4 | 10.6 | 10.9 |
| 3 | D | CCA generation | 6.5 | 6.9 | 7.0 | 7.4 | 7.9 | 8.0 | 8.0 | 8.2 | 8.3 | 8.5 | 8.7 | 8.9 | 9.1 | 9.2 |
| 3 | D | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.3 | 1.2 | 1.3 | 1.2 | 1.1 | 1.0 | 0.9 |
| 3 | D | CCA Reserve Fund | 1.0 | 0.5 | 0.4 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 3 | D | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 10.9 | 11.2 | 12.8 | 13.1 | 13.3 | 13.7 | 14.0 | 14.3 |
| 3 | R | CCA generation | 6.5 | 7.0 | 7.2 | 7.8 | 8.8 | 9.0 | 9.3 | 9.5 | 9.7 | 9.9 | 10.1 | 10.3 | 10.5 | 10.7 |
| 3 | R | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.4 | 1.3 | 1.1 | 0.9 | 1.0 | 1.0 | 0.9 | 0.8 | 0.7 |
| 3 | R | CCA Reserve Fund | 1.0 | 0.6 | 0.4 | 0.1 | 0.1 | 0.0 | 0.1 | 0.0 | -0.4 | -0.8 | -0.3 | 0.0 | 0.0 | 0.0 |
| 3 | R | PG&E generation | 9.7 | 9.8 | 9.9 | 10.3 | 10.6 | 10.9 | 11.0 | 10.8 | 10.2 | 10.2 | 10.5 | 10.8 | 11.0 | 11.3 |
| 3 | L | CCA generation | 6.5 | 6.9 | 7.0 | 7.4 | 7.9 | 8.0 | 8.0 | 8.2 | 8.3 | 8.5 | 8.7 | 8.9 | 9.1 | 9.2 |
| 3 | L | Exit fees | 2.1 | 2.1 | 2.0 | 1.9 | 1.5 | 1.5 | 1.4 | 1.2 | 1.1 | 1.2 | 1.1 | 1.0 | 0.9 | 0.8 |
| 3 | L | CCA Reserve Fund | 0.1 | -0.1 | 0.0 | 0.0 | 1.2 | 0.0 | 0.0 | 0.0 | -0.2 | -0.7 | -0.3 | 0.0 | 0.0 | 0.0 |
| 3 | L | PG&E generation | 8.7 | 8.8 | 8.9 | 9.3 | 9.5 | 9.8 | 9.8 | 9.7 | 9.2 | 8.9 | 9.1 | 9.4 | 9.6 | 9.8 |
| 3 | S | CCA generation | 7.1 | 7.6 | 7.8 | 8.4 | 9.2 | 9.4 | 9.8 | 10.0 | 10.2 | 10.4 | 10.6 | 10.8 | 11.1 | 11.3 |
| 3 | S | Exit fees | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| 3 | S | CCA Reserve Fund | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 3 | S | PG&E generation | 9.0 | 9.2 | 9.3 | 9.7 | 9.9 | 10.3 | 10.4 | 10.4 | 10.1 | 10.1 | 10.3 | 10.5 | 10.7 | 10.9 |

# Appendix E. Greenhouse Gas Emissions and Costs

In Chapter 3 of the report, MRW provided an estimate of Alameda CCA's annual Greenhouse Gas (GHG) emissions and compared these with the emissions for the same load under the PG&E supply portfolio. The methodology used to calculate both figures is included in this appendix, along with an estimate of Alameda CCA's cost of emissions from purchased power ("indirect emissions").

## Methodology for calculating Alameda CCA's indirect GHG emissions

GHG emissions for Alameda CCA will be indirect since the CCA does not plan to generate its own power (*i.e.,* the emissions are embedded in fossil-fuel power that the CCA purchases). These emissions are estimated based on (1) a forecast of the emissions rate for Alameda CCA's fossil generation supply and (2) a forecast of the amount of Alameda CCA's fossil generation supply, developed by subtracting expected renewable and hydroelectric generation from the projected wholesale power requirement to serve the CCA's load.[40]

MRW calculated the emissions rate for Alameda CCA's fossil generation supply by estimating the amount of natural gas that will need to be burned to generate the CCA's fossil generation and the GHG emissions rate for natural gas combustion.[41] The amount of natural gas needed was estimated based on the average heat rate for the marginal generation plants on the CAISO system. MRW used public data from CAISO's OASIS platform and Platt's Gas Daily reports to calculate this average heat rate for 2015.[42] MRW extended the forecast to 2030 using the expected changes to the average heat rate in California from the EIA's *2015 Annual Energy Outlook.*[43]

MRW estimated the total annual GHG emissions for the Alameda CCA program as a product of the total energy purchased at wholesale electric market (kWh) and the rate of GHG emissions (tonnes $CO_{2\text{-equivalent}}$/kWh).

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[40] MRW assumed no GHG emissions for the renewable and hydroelectric supply.

[41] The GHG emissions rate for natural gas combustion is obtained from U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

[42] MRW calculated the average heat rate of the marginal generation plants in 2015 by dividing the monthly average wholesale electric market price, net of operations and maintenance costs and GHG emissions costs, by the monthly average natural gas price. For the electricity prices, we used the average of the 2015 hourly locational marginal price for node TH_NP15_GEN-APND; for the natural gas prices, we used the average of burnertip natural gas price for PG&E.

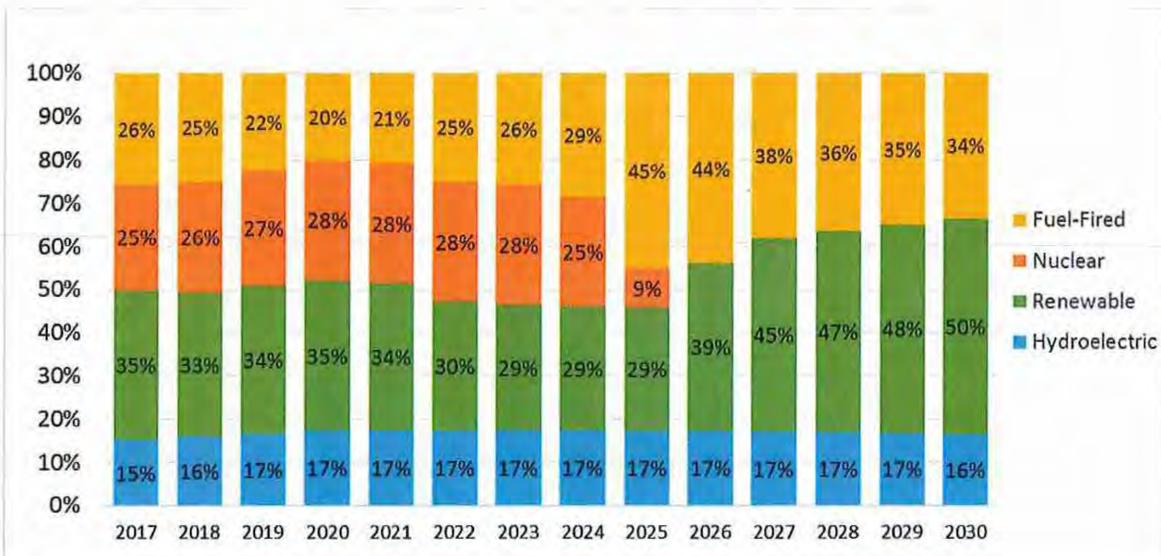
[43] U.S. Energy Information Administration. "2015 Annual Energy Outlook," Table 55.20, Western Electricity Coordinating Council. (Note that EIA does not provide a forecast of the marginal heat rate.)

## Methodology for calculating GHG emissions under PG&E's supply portfolio

MRW calculated the GHG emissions for the Alameda CCA load under the PG&E supply portfolio by summing the emissions from all resources in PG&E's portfolio. MRW assumed no GHG emissions from renewable power, hydroelectric power, or nuclear generation. In order to maintain a consistent comparison, MRW used the same emissions rate to calculate the emissions from PG&E's fossil-fuel power as used for the Alameda CCA wholesale market purchases.

In order to support the analysis on Chapter 3 of the report, Figure 2 shows the PG&E portfolio. Before the closure of the Diablo Canyon, MRW estimated more than 70% of PG&E's generation portfolio based on non-fuel-fired resources. After 2025, the non-fuel-fired resources share falls to 65% according MRW estimates.

**Figure 2 PG&E's generation portfolio**




## GHG allowance prices and GHG indirect costs

MRW developed a forecast of the prices for GHG allowances based on the results of the California Air Resources Board's (ARB's) auctions for Vintage 2015 allowances,[44] increased annually in proportion to the auction floor price increases stipulated by the ARB's cap-and-trade regulation.[45]

[44] Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

[45] California Code of Regulations, Title 17, Article 5, Section 95911.

**Table 2 GHG Allowances price, $ per allowance**

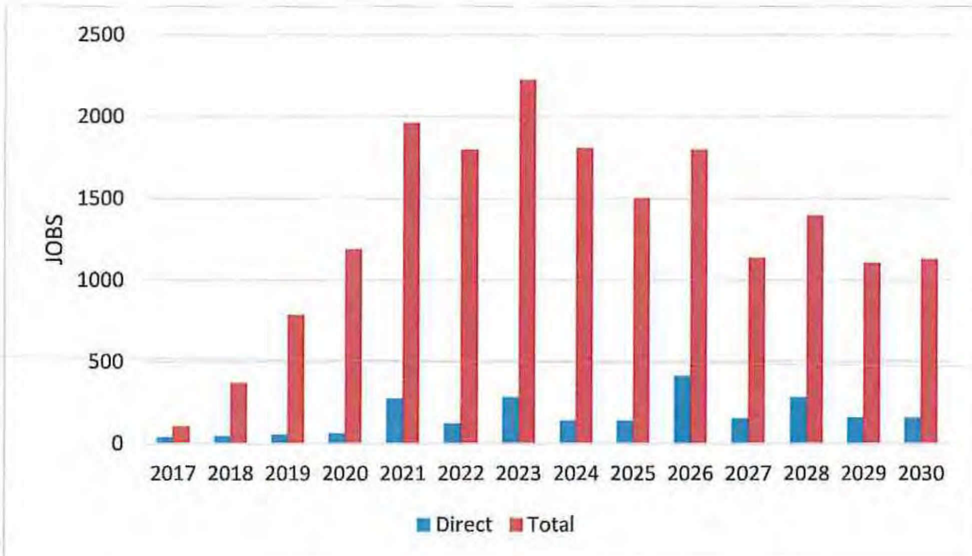
| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14.0 | 15.0 | 16.0 | 17.2 | 18.4 | 19.6 | 21.0 | 22.4 | 24.0 | 25.6 | 27.4 | 29.3 | 31.3 | 33.5 |

MRW used these GHG allowances prices to calculate both PG&E's GHG allowances costs (direct and indirect), which are included in the PG&E rate forecast, and Alameda CCA's indirect GHG costs. The indirect GHG costs for Alameda CCA will be included in the cost of the wholesale market energy purchases. MRW estimated that these costs will be, on average, $5 per MWh delivered over the 2017-2030 period.

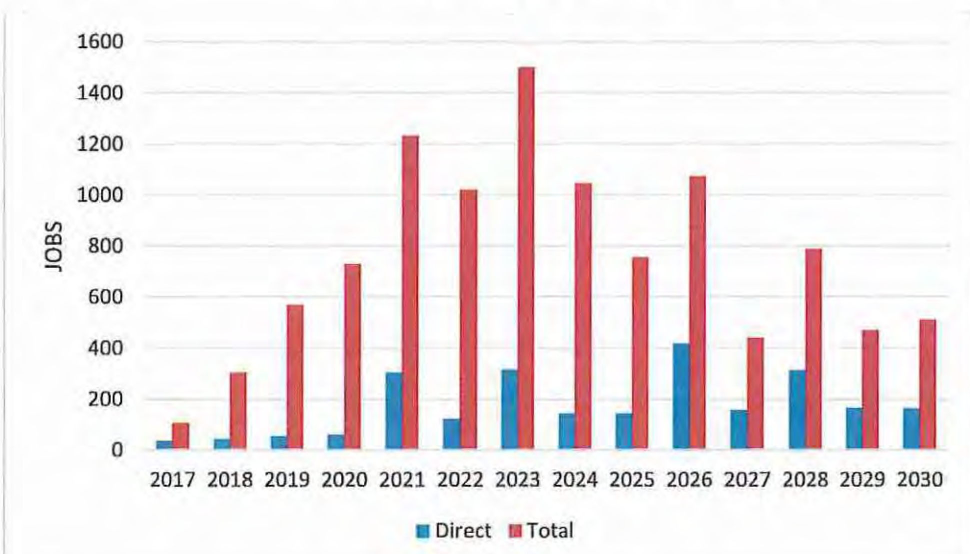
# Appendix F. Macroeconomic Analysis

Additional results are provided for scenario 2 and 3 to match those presented in Chapter 5 for scenario 1. High-level results are provided for the *rest of California* region. Overview information on the REMI Policy Insight model is provided in the last section.

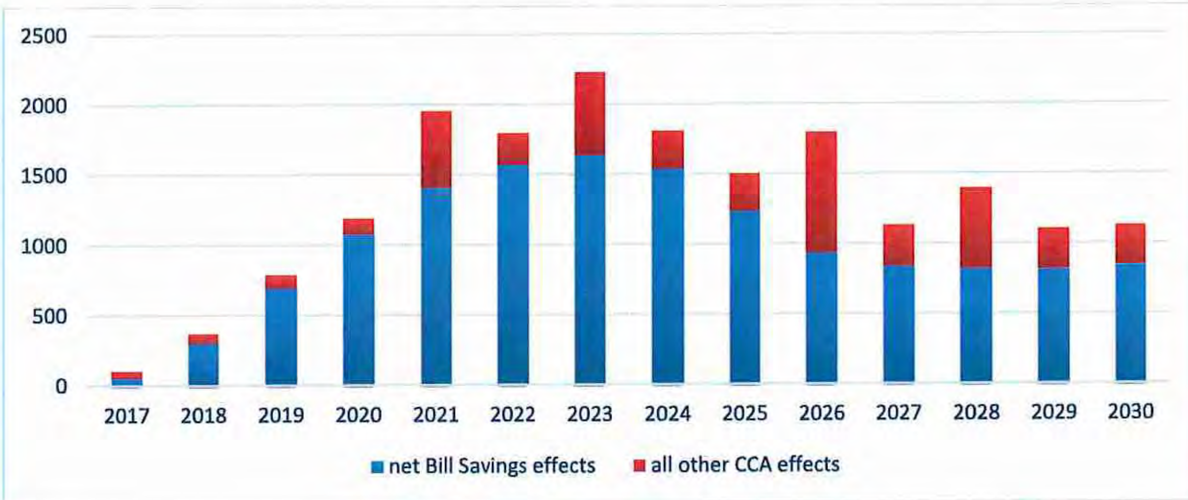
**CCA Scenario 2 County Job Impacts**



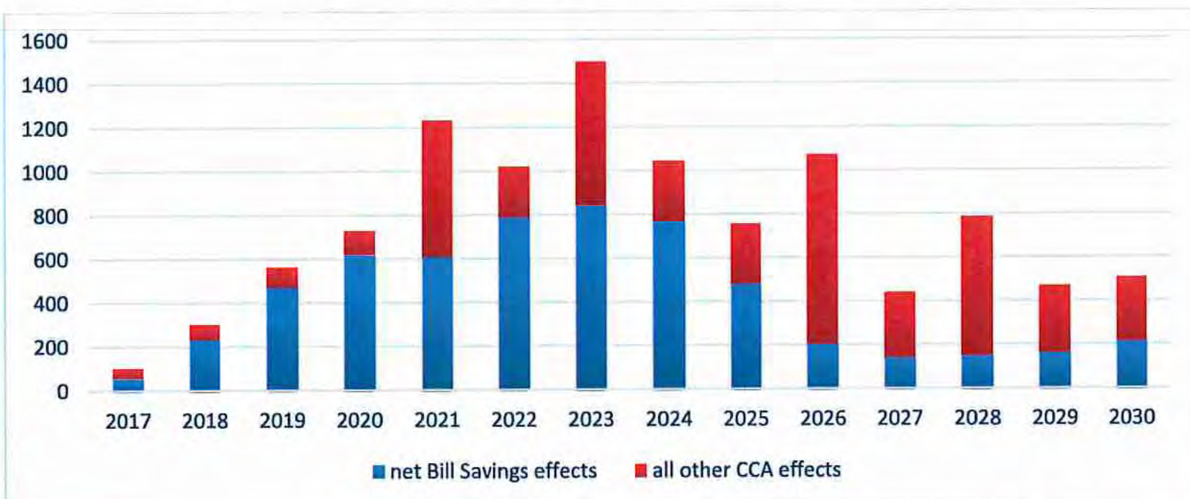

**CCA Scenario 3 County Job Impacts**



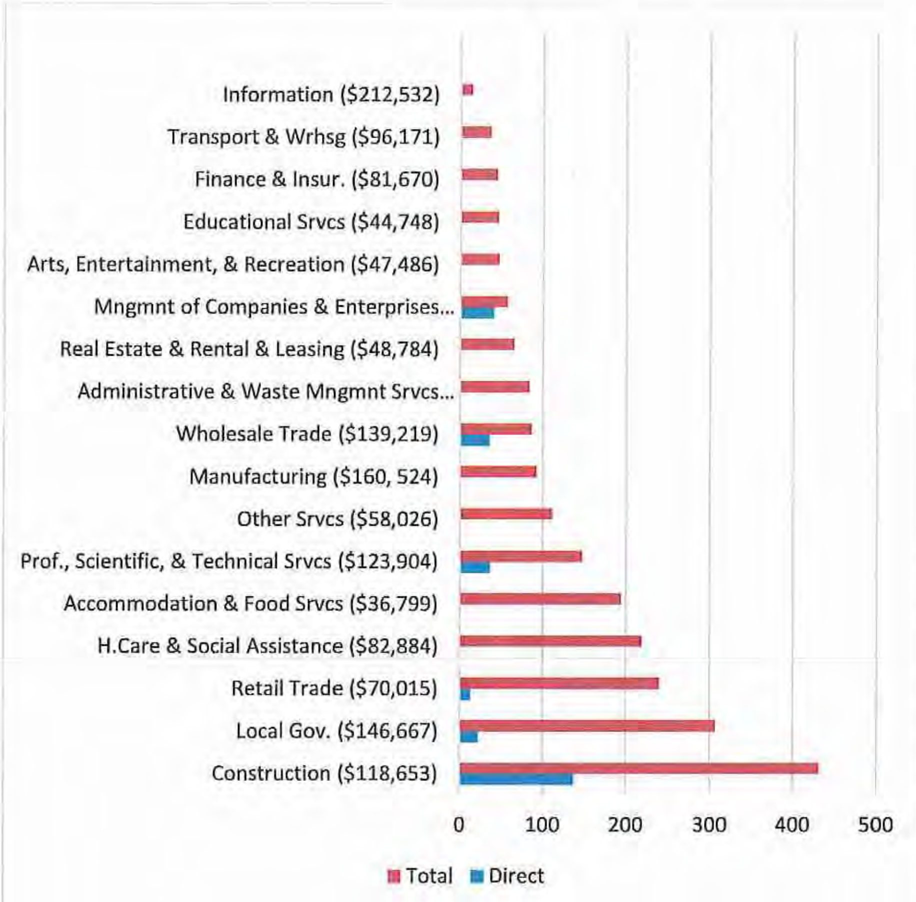
## Alameda County CCA Scenario 2 Total Jobs Impacts by Source




## Alameda County CCA Scenario 3 Total Jobs Impacts by Source



**Alameda County Jobs Changes by sector (annual earnings per worker), Scenario 2, 2023**



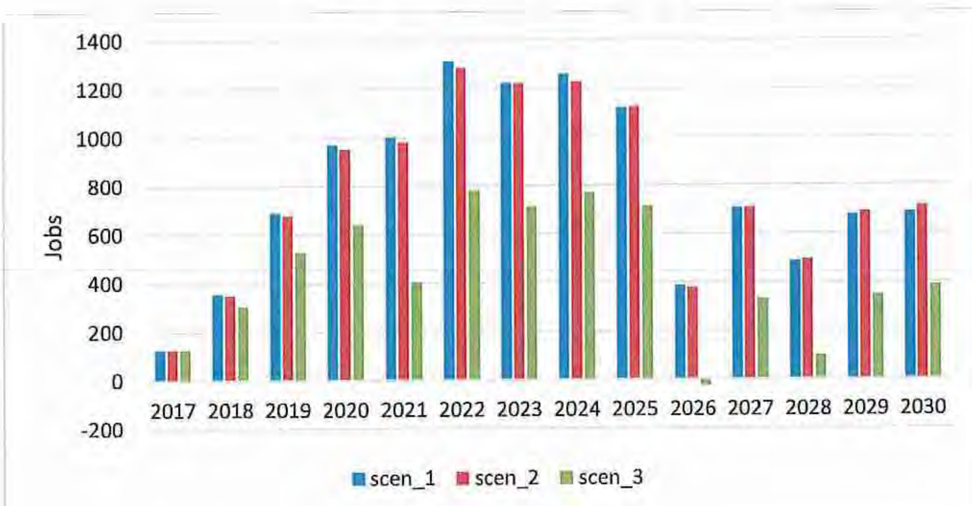
## Alameda County Jobs Changes by sector (annual earnings per worker), Scenario 3, 2023


## Results for rest of California Economy

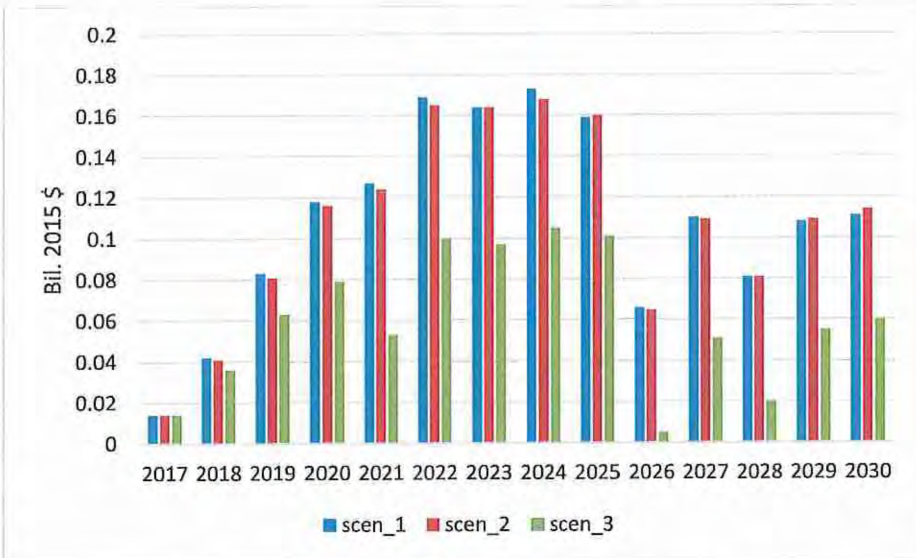
| CCA Scenario | rest of CA Impacts | | | | |
|---|---|---|---|---|---|
| | *local capture* on changes in RE investments & O&M (bil$) ...... | *as % of roCA's Total project cost* | *as % of region's expected Economic Activity* | **Avg. Annual Direct Jobs** | **Avg. Annual *Total* Jobs** |
| 1 | -$0.155 | 53% | -0.0002% | -30 | 786 |
| 2 | -$0.143 | 58% | -0.0002% | -24 | 780 |
| 3 | -$0.115 | 40% | -0.0002% | -33 | 436 |

The local renewable investment (O&M) changes are negative as a result of expected cancellation of future PG&E renewable project and the amount of CCA funded renewable projects that would be sited in this region. The reason the *rest of California* region can create positive *total* job impacts despite small negative average annual *direct* job impacts is due economic flows between the county and this large region. In any scenario the Alameda County business segments in particular are benefitted by lower electric rates which was shown to expand their business (and jobs). When a business grows it requires more supplies and services and some of those come as *'imports from elsewhere in the state.'* Working age households that commute into Alameda County from outside also gain earned income to spend in the *rest of California* region. Since scenario 3 has the lowest rate savings it is also associated with the smallest *total* job impact in the *rest of California* region.

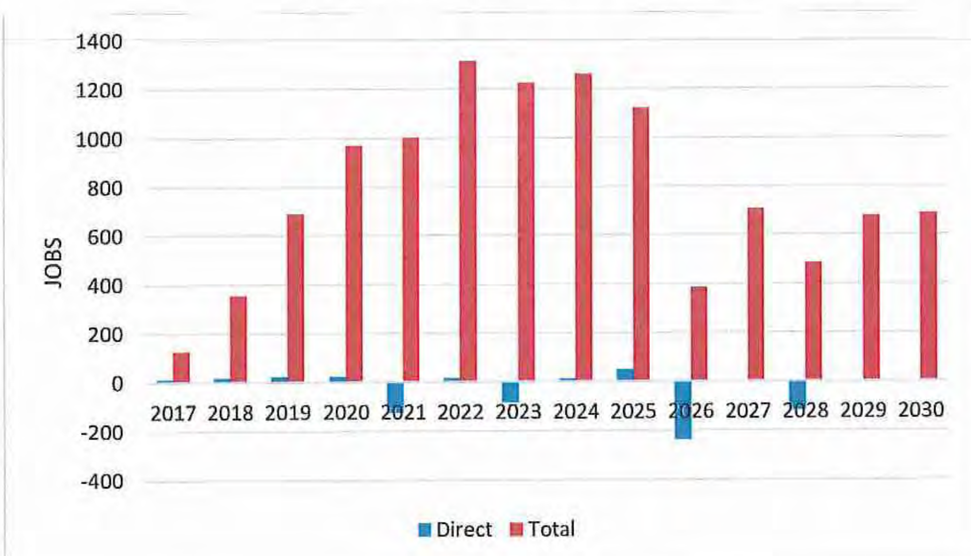
**Rest of California Total Job Impacts by Scenario**



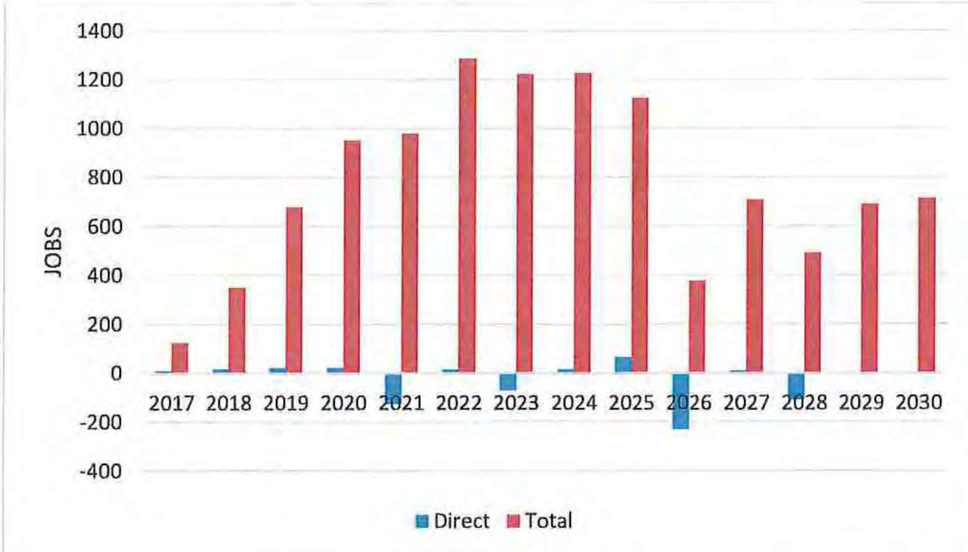
## Rest of California Total GRP Impacts by Scenario



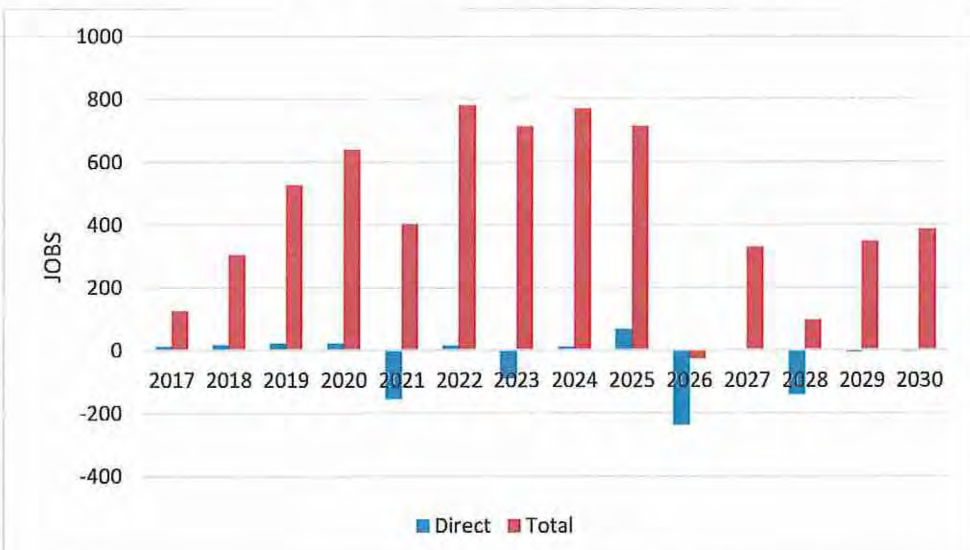

## CCA Scenario 1 Rest of California Job Impacts



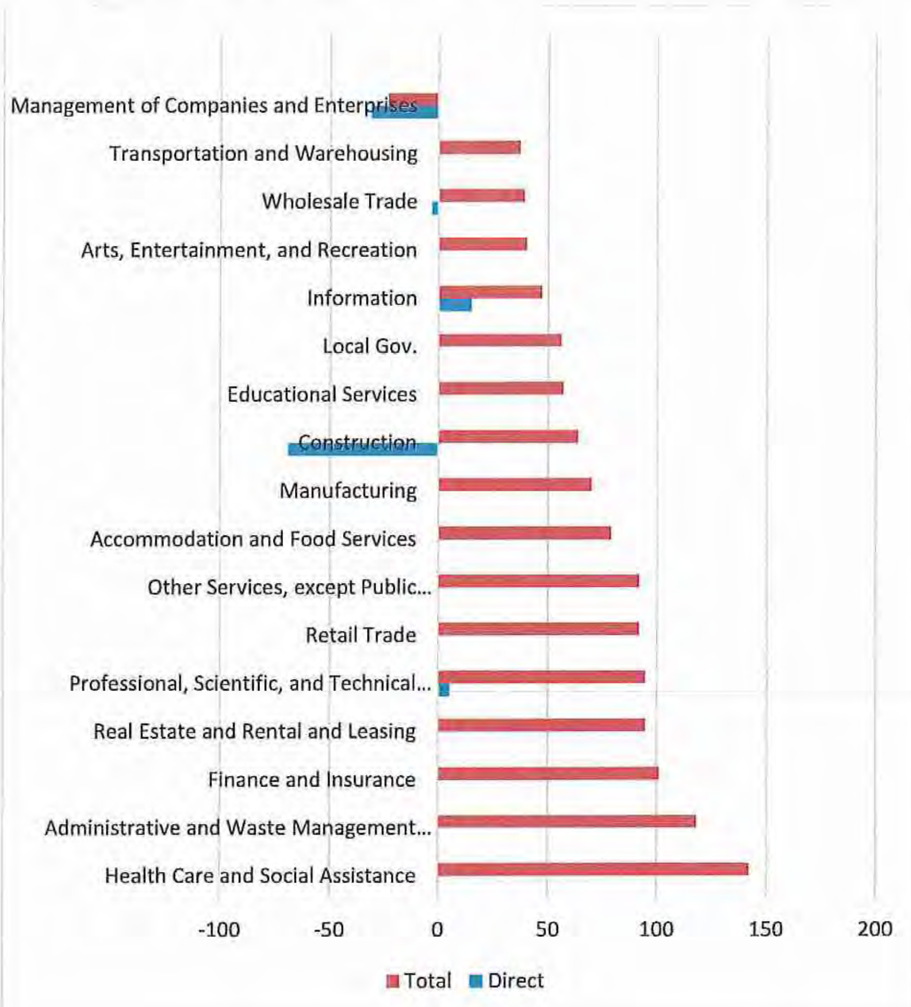
## CCA Scenario 2 Rest of California Job Impacts




## CCA Scenario 3 Rest of California Job Impacts



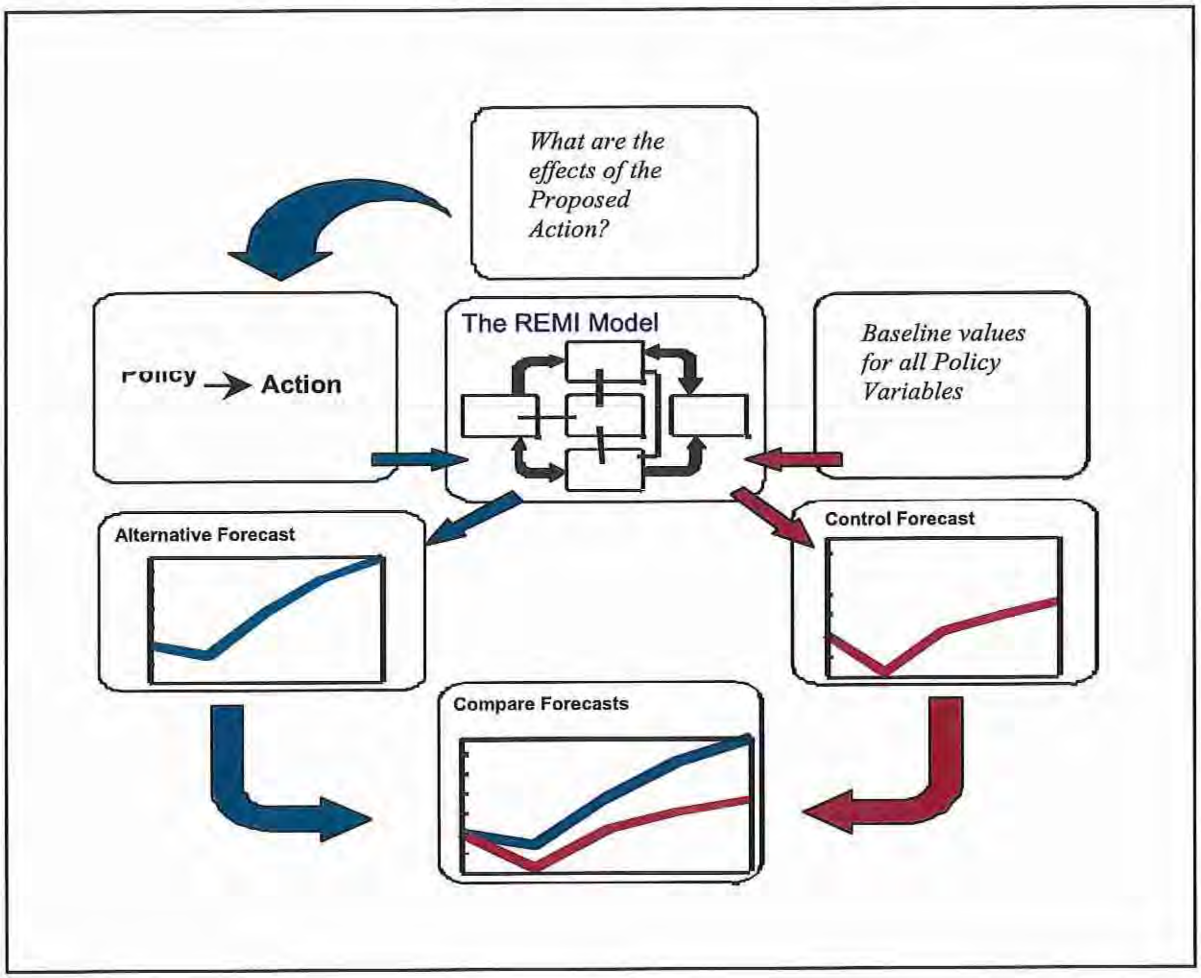
## Rest of California Jobs Changes by sector, Scenario 1, 2023



## About the REMI Policy Insight Model

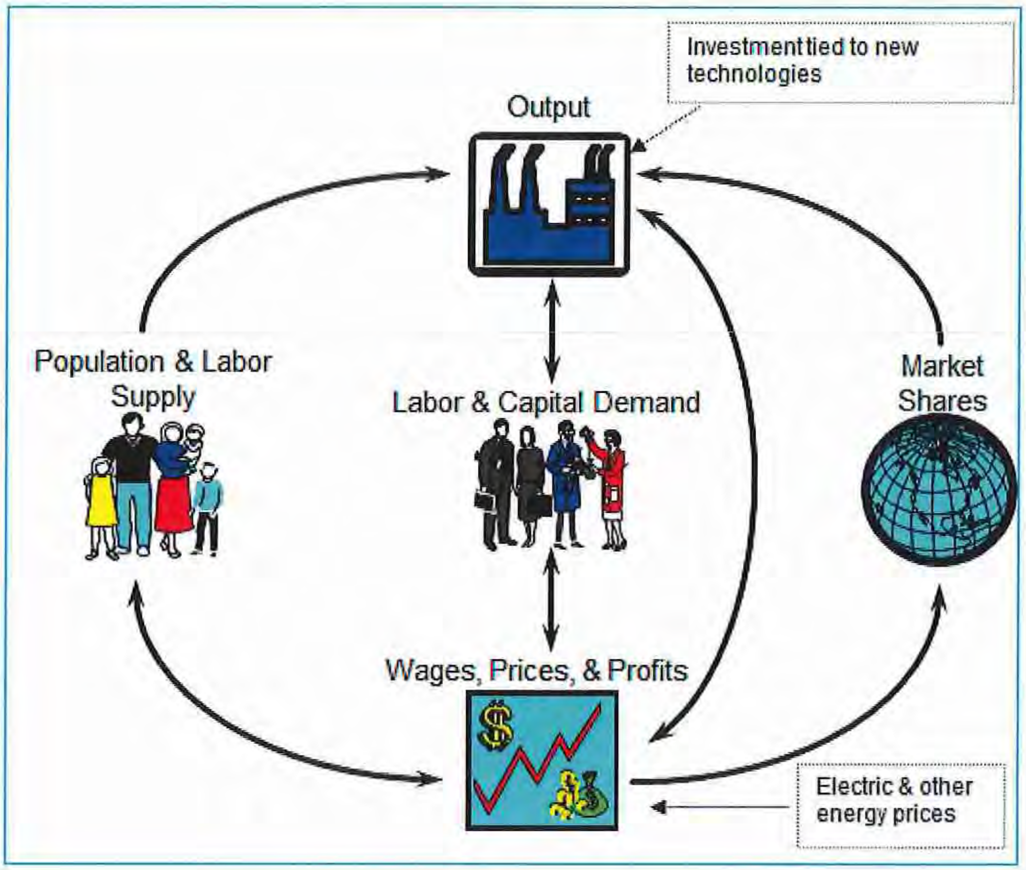
A software analysis forecasting model developed by Regional Economic Models, Inc. (REMI) of Amherst Massachusetts in the mid 1980's. It has a broad national customer base among public agencies, academic institutions, and the private-sector. It is also used in Canada (NRCan), and among other international clients. The model configuration used for this study consisted of 18 aggregate private-sector industries, plus a farm sector, a combined state/local government sector and two federal government sectors.

**Economic Impacts Identified with the REMI Model**




In the above figure, the central box "The REMI model" is the engine for predicting the economic and demographic dimensions of a *region-of-impact* (here Alameda County) under *no-action* (or Control forecast) and with a proposed CCA (alternative forecast). The engine is a combination structural econometric model, part input-output transactions, all with general equilibrium features – meaning *an economy can encounter a disruption (positive or negative), and over time (typically 1-3 years depending on the scale of the region and the size of the shock) re-adjust back* *to an equilibrium*. The diagram below depicts the organization of the REMI regional model in terms of the major blocks functioning in an economy and the arrows denote the feedback accounted for. Keep in mind this portrayal is at a very high-level, sparing the industry-specific details. Scenario specific changes are inserted through policy variable *levers* into the appropriate block of the model. There is another important dimension of economic response for the key region-of-impact that effectively layers on top of the below diagram – interactions with another regional economy. That additional region - *rest of California* -was explicitly modeled at the same time. The REMI model captures the flows of monetized goods and services, and commuter labor between regions when one (or both) is *shocked* by introduction of a CCA.

**Core Logic of the REMI Model**



## Appendix G. Energy Efficiency

# Contents

## Energy Efficiency Research Objectives

The research undertaken by the MRW team to inform the potential for energy efficiency within the Alameda County CCA feasibility study, and associated REMI model, include the following objectives:

1. Provide a brief overview of key legislative, regulatory, and local market initiatives influencing the potential for energy efficiency.
2. Provide an assessment of the technical, economic, and market potential for energy efficiency based on tools used by the CPUC to assess potential within PG&Es service territory.
3. Provide general guidance on where CCA energy efficiency initiatives might achieve energy efficiency that are incremental to current PG&E goals.
4. Assess the current funding environment and potential costs for CCA administered energy efficiency initiatives.
5. Define the economic inputs for energy efficiency for the REMI model.

## Legislative, Regulatory, and Local Market Environment for Energy Efficiency

The potential for any administrators of energy efficiency programs to deliver savings is influenced by underlying regulatory factors along with the ability of a community to deliver energy efficiency products and services. The following discussion provides a brief summary of the regulatory and service delivery environment in which energy efficiency programs administered by an Alameda County CCA would likely begin operating.

### Legislative Environment

Recent legislation that is now defining the regulatory landscape under which CCA administered energy efficiency programs would operate include;

**SB 350.** Signed by the Governor on October 7, 2015, Senate Bill (SB) 350, the Clean Energy and Pollution Reduction Act of 2015 requires the State Energy Resources Conservation and Development Commission to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. SB 350 allows CCA energy efficiency programs to count towards statewide energy efficiency targets, and will likely have a significant impact on funding levels available for energy efficiency, and on administrative and goal setting requirements for energy efficiency program administrators, including CCA's.

**AB 802.** Effective September 1, 2016, the CPUC will authorize electrical and gas corporations to provide incentives, rebates, technical assistance, and support to their customers to increase the energy efficiency of existing buildings. This legislation may provide for new measure acceptance and cost effectiveness criteria that could expand opportunities for energy efficiency, including new High Opportunity Program Designs (HOPPS) currently under design.

## Regulatory Environment

**Rulemaking 09-11-014.**[46] This ruling sought to clarify how CCAs will be able to participate in administering energy efficiency programs on behalf of the customers and/or geographic areas they serve. The ruling outlines how the commission would assess the benefits of the party's proposed program to ensure that the program meets the following objectives:

- Is consistent with current administrative rules as established pursuant to Section 381 of the public utility code.
- Advances the public interest in maximizing cost-effective electricity savings and related benefits.
- Accommodates the need for broader statewide or regional programs.

The ruling further defined the methods and guidelines for budgeting energy efficiency programs administered by a CCA, and also clarified the capacity of CCA to administer energy programs, that may also serve non-CCA customers located within the CCA's operating region.

**Decision 15-10-028.** As part of CPUC Decision 15-10-028 (a component of the rulemaking 13-11-005), the operation of energy efficiency programs will transition to a 'rolling portfolio' model. Historically, California has allocated ratepayer funding for energy programs through decisions made on a one, two, or three-year cycle by the California Public Utilities Commission (CPUC). This cyclical funding resulted in significant administrative burdens in the planning, assessment, and uncertainty regarding ongoing programmatic operations that potentially limited customer participation. The rolling portfolio concept, defined in the fall of 2015, initiates the conversion to a "rolling portfolio" cycle. Through this cycle, energy efficiency (EE) program administrators, including CCA's, are responsible for the creation of 5-year "business plans" in an effort to decrease administrative burden, increase transparency, and provide a more stable business platform from which to engage customers.

## Local Market Environment

Alameda County has an existing and robust market of firms engaged in energy efficiency, including the capacity to provide innovative products and services to all market sectors including energy efficiency, renewable generation, energy storage, and demand response capabilities. As such, it is very likely that adequate administrative and technical support availability will be required to rapidly launch programs that would have a high likelihood of success. The following provides a brief, inexhaustive overview of this capacity.

**StopWaste.** StopWaste began operations in 1976 as a public agency responsible for reducing the waste stream in Alameda County. StopWatse is governed jointly by three Boards, including the Energy Council that was formed in Spring 2013 as a Joint Powers Agency to seek funding on behalf of its member agencies to develop and implement programs and policies that reduce

[46] Administrative Law Judge's Ruling Regarding Procedures For Local Government Regional Energy Network Submissions For 2013-2014 And For Community Choice Aggregators To Administer Energy Efficiency Programs

energy demand, increase energy efficiency, advance the use of clean, efficient and renewable resources, and help create climate resilient communities. StopeWaste and the Energy Council will be key stakeholders in any distributed energy resource activities associated with an Alameda County CCA.

**Bay Area Regional Energy Networks (BayREN).** BayREN offers 2 programs that provide benefits to Alameda County residential facilities in Alameda County, including single and multifamily dwellings. BayREN also offers commercial PACE programs in addition to a proposed innovative financing pilot program, referred to Pay-As-You-Save (PAYS). PAYS intends to retrofit 2,000 multifamily housing units in Hayward with an array of resource efficiency measures that will assist multifamily property owners monitor and reduce both water and energy use. All BayREN programs offered in Alameda County are administered by StopWaste.

**PG&E.** The 2015 PG&E portfolio includes 66 programs available throughout Alameda County that provide financial incentives and technical support for energy efficiency activities. These programs, listed in Appendix A, cover all market sectors and energy end uses and are representative of programs that will likely continue to operate in the coming years. PG&E spends roughly $300M to $400M annually across its service territory on programs and marketing efforts designed to promote energy efficiency.

**Local Energy Efficiency and Sustainability Firms.** The County has substantial local resources including public institutions and numerous public and private companies, some of which have been in continuous operation since the early 1980s.

In summary, the preceding discussion on the legislative, regulatory and market environment for energy efficiency indicates;

1. The legislative environment created by SB350, AB802, AB758, AB32 are expanding the opportunities for funding and program innovations for distributed energy resources, such as energy efficiency, along with the capacity of CCA's to implement programs.
2. Structural changes now underway through the rolling portfolio initiative (RP Decision) may reduce the overall administrative burden on program administrators and provide a more stable business platform in the form of consistent funding over longer term program cycles. Regulatory proceedings are continuing to address procedural issues that will clarify the rules of CCA program operation and budgeting issues.
3. Alameda County has significant local delivery capacity, including firms with a long history of successfully operating energy efficiency and resource management programs, including the technical and administrative capabilities needed to successfully deliver on regulatory requirements. This implies that innovative programs that incorporate emerging concepts such as High Opportunity Projects and Programs (HOPPS) or integrated demand side management (IDSM) techniques can be developed and implemented with acceptable risk.
4. Risks exists in the form duplicate efforts between established utility programs and CCA administered programs, and also the potential for customer confusion from other market entrants. In the longer term, the role of energy efficiency and related opportunities is

evolving as advances in renewable energy and storage technology change the economics associated with avoided costs, greenhouse gases priorities, and operational dynamics associated with grid management. This indicates some uncertainty in program design and delivery priorities.

## Energy Efficiency Potential

The following section provides an estimate of the overall level of energy efficiency potential in Alameda County as derived from a publically available potential model, and also provides several examples of incremental potential not represented in this model that may be developed by CCA administered programs.

### Types of Energy Efficiency Forecasts and Alameda County Market Potential

Forecasts of energy efficiency potential are generally based on three levels of screening, as illustrated in **Error! Reference source not found.** and discussed below.

**Figure 3. Diagram of Types of Energy Efficiency Potential**


1. **Technical Potential Analysis.** Technical potential is defined as the amount of energy savings that would be possible if all technically applicable and feasible opportunities to improve energy efficiency were taken, including retrofit measures, replace-on-burnout measures, and new construction measures. Technical potential varies over time depending on market adoption and saturation of existing technologies, and the development of new technologies that are more efficient than the current market baseline. It is also a very notional metric intended to provide a benchmark that compares the current market with a hypothetical market where the most current energy efficiency technologies have been installed, and all machines and systems may be upgraded to a high level of efficiency.

2. **Economic Potential Analysis.** Using the results of the technical potential analysis, the economic potential is calculated as the total energy efficiency potential available when limited to only cost-effective measures. All components of economic potential are a subset of technical potential. Economic potential is less than technical potential because it considers the influence of financial payback on customer selection, along with regulatory requirements that exclude certain energy efficiency activates based on cost effectiveness criteria. Economic potential is also a notional metric which adjusts technical potential to account for various regulatory and market economic constraints.
3. **Market Potential Analysis.** The final output of most potential studies is a market potential analysis which is defined as the energy efficiency savings that could be expected to occur in response to specific levels of program funding and customer participation based on assumptions regarding market influences and barriers. All components of market potential are a subset of economic potential. Some studies also refer to this as the "Maximum Achievable Potential." Defining market potential requires an estimate of how much market activity occurs each year where there is an opportunity to install efficient equipment. The opportunity is often related to natural stock turnover (i.e., old equipment burns out and needs to be replaced) or the favorable economic conditions such that residents and businesses invest in energy efficiency, or the influence of codes and standards. Market potential generally does not exceed 1% of total electricity consumption in any given year, but is influenced by the level of spending and the development of new and innovative market interventions.

The assessment of energy efficiency potential in Alameda County completed for this feasibility study used outputs from the 2013[47] and 2015[48] Energy Efficiency Potential and Goals studies developed by the CPUC. These CPUC studies define the technical and economic potential for energy efficiency in PG&E's service territory, and also determine the market potential used to set energy efficiency production goals and budgets for PG&E's energy efficiency programs. Because of its size, varied economy, diverse demographics, and range of climates it is likely that both energy use characteristics and the potential for energy efficiency in Alameda County is consistent with the potential for energy efficiency in PG&E's overall service territory, with some exceptions such as a reduced presence of agricultural and oil extraction loads found elsewhere in the state. For example, a review of Alameda County electric usage data provided to the MRW team for this analysis indicates that the residential sector accounted for 29% of sales to the County by PG&E in 2013 and 2104, with non-residential sales accounting for the remaining 71%. Similarly, the CEC electric demand forecast for the overall PG&E service territory[49] indicates that the residential sector accounted for 31% of total system-wide sales for those same years, with nonresidential sales accounting for 69% of sales, consistent with the distribution of sales in Alameda County. Based on these consistencies in markets and energy usage, this analysis concludes that energy efficiency potential for electricity in PG&E's overall service

[47] 2013 California Energy Efficiency Potential and Goals Study, Final Report. Prepared for the California Public Utilities Commission by Navigant Consulting, Inc. February 14, 2014

[48] Energy Efficiency Potential and Goals Study for 2015 and Beyond, Stage 1 Final Report. Prepared for the California Public Utilities Commission by Navigant Consulting, Inc. Reference No.: 174655, September 25, 2015

[49] Form 1.1 – STATEWIDE California Energy Demand 2015 Revised - Mid Demand Case, Electricity Consumption by Sector (GWh)

territory can be allocated to Alameda County in proportion to overall electricity sales, which average approximately 7.5% of total annual PG&E electricity sales.

Figure 4 shows technical and economic electric potential as a percent of sales as presented in the 2015 CPUC potential study. Technical and economic potential start at approximately 21% and 18%, respectively in 2016 and drop to approximately 16% and 15% by 2024. Using this forecast along with PG&E electric sales data to Alameda County, **Error! Reference source not found.** provides a range of estimates of technical and economic potential during this same timeframe. This provides a notional indication of the amount of energy efficiency potential that exists in Alameda County that PG&E and any CCA administered programs would be serving.

**Figure 4. Potential for Electric Savings as a Percent of Annual Sales**

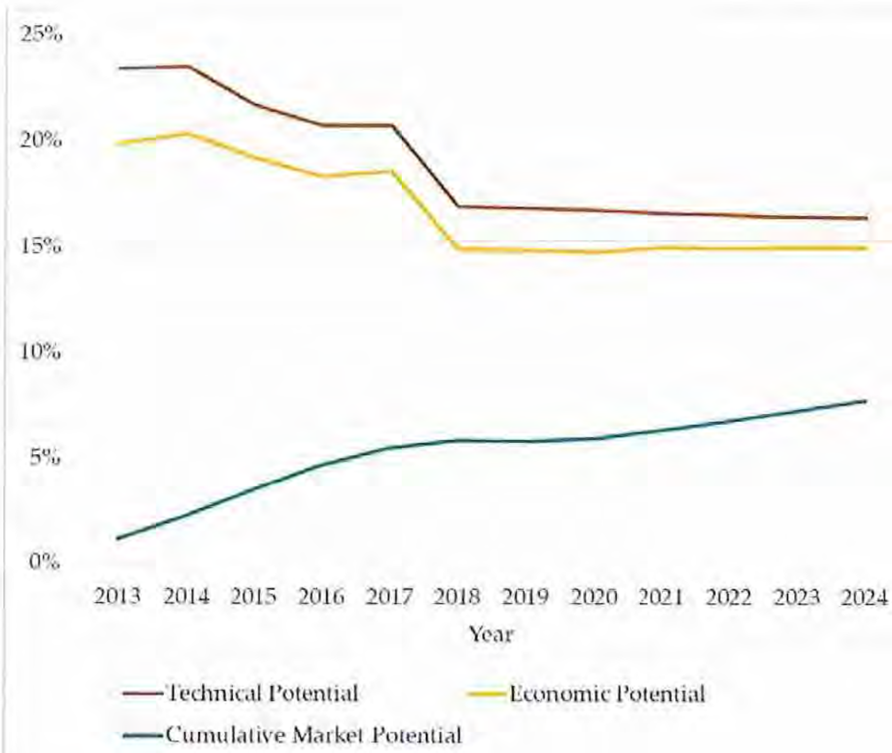


**Table 3. Alameda County Average Technical and Economic Energy Efficiency Potential**

| Metric | Technical Potential | | Economic Potential | |
|---|---|---|---|---|
| Range (% of sales) | 21% | 16% | 18% | 15% |
| Potential (GWh) | 1,623 | 1,237 | 1,391 | 1,159 |

Table 3**Error! Reference source not found.** provides a summary forecast of the market potential for energy efficiency in Alameda County based on this same approach. It is important to note that the difference between technical, economic potential and market potential is that market potential represents the annual rate at which efficient equipment is installed, or the percent of the population that adopts energy efficiency practices. As such, market potential is a smaller value when compared to technical or economic potential because the natural cycle at which equipment burns out and must be replaced tends to regulate the rate at which new, high efficiency equipment can be installed, given reasonable program, market incentives, and assumptions about customer adoption rates. Market potential also recognizes that only a fraction of customers actually install high efficiency systems when it is time to replace equipment. The row labelled " PG&E Goals" represents Alameda County's share of the PG&E 2015 EE program portfolio savings target.[50] The row labelled "High Savings Scenario" represents Alameda County's share of the more aggressive energy efficiency scenarios for PG&E as defined by the 2013 CPUC potential study high savings scenario.[51] The row labelled "Incremental Potential" is the difference between PG&E's 2015 portfolio goals, and the high savings scenario and represents the total market potential that could be served by CCA administered programs.

**Table 4. Alameda County Incremental Energy Efficiency Market Potential (GWh)**

| Year | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|
| **Alameda Component of PG&E Goals** | 25.9 | 35.8 | 24.6 | 29.4 | 41.1 | 48.2 | 50.0 | 25.9 |
| **Alameda of High Savings Scenario** | 44.2 | 59.8 | 56.6 | 65.6 | 71.7 | 84.2 | 88.4 | 44.2 |
| **Incremental Potential** | 18.3 | 24.0 | 32.0 | 36.3 | 30.6 | 36.0 | 38.4 | 18.3 |

[50] Net GWh, as defined by the CEC Mid Additional Achievable Energy Efficiency (AAEE) forecast

[51] Referred to as the High AAEE Potential Scenario

The forecast presented in **Error! Reference source not found.** represents an estimate of energy efficiency potential that is "net" of free-riders and represents the following types of energy efficiency measures and market sectors:

- Emerging Technologies
- E Program Measures
- Residential
- Commercial
- Industrial-Manufacturing

This forecast does not include energy efficiency potential associated with building codes, appliance standards, or estimates for the agricultural or mining market sectors.

## Examples of Potential Programs and Measures

While there are countless opportunities and approaches to achieve energy efficiency, following presents several examples of technologies and programs that will yield savings above what is being targeted through the current portfolio of PG&E programs operating in Alameda County. This includes initiatives that might compliment and leverage existing technologies or programs, or highlight emerging opportunities that are in design or in early deployment.

**High Efficacy LED Lighting. Commercial and residential lighting currently make up 25% of California's total statewide electricity consumption.[52] LED lighting will provide increasing opportunities for energy savings in the coming years as prices continue to fall and LED efficiency (i.e., efficacy or lumens per watt of power, lm/w[53]) improves. Figure 5 shows that between 2020 and 2030, LEDs lighting will achieve efficiencies of 200 lm/w and prices will reach parity with current CFL and incandescent prices within the next 10 years.**

**Table 5 shows that 200 lm/w represent a 74% reduction in current average residential lighting efficiency, and approximately a 50% reduction in average non-residential lighting efficiency. As the LED adoption rates at present are low, and because the technology and costs are both evolving rapidly and favorably, the potential exists for CCA energy efficiency programs to drive this transition by focusing on high efficacy LED applications. The potential between the current market efficacy for lighting shown in**

Table 5 and a full market penetration of 200 lm/w LED lighting represents a reduction in state wide (and Alameda County) consumption of electricity of approximately 14%. While programs do exist that promote LED lighting, a program focused on the highest efficacy products, some of which currently exceed 140 lm/w[54], would provide savings that are incremental to many products

[52] California Commercial Saturation Survey. Itron Inc., August 2014 Table 5-82

[53] U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release

[54] http://www.cree.com/LED-Components-and-Modules/Products/XLamp/Discrete-Directional/XLamp-XPE-HEW

currently being installed. Capturing the highest savings possible from LED lighting and targeting 200 ln/w technologies is very important because LED lamps operate for between 20 and 30 years, and once lower efficacy lamps are installed it will be difficult to capture rapidly improving efficiencies.

**Figure 5. Trends in LED Lighting Efficacy and Cost per Bulb**

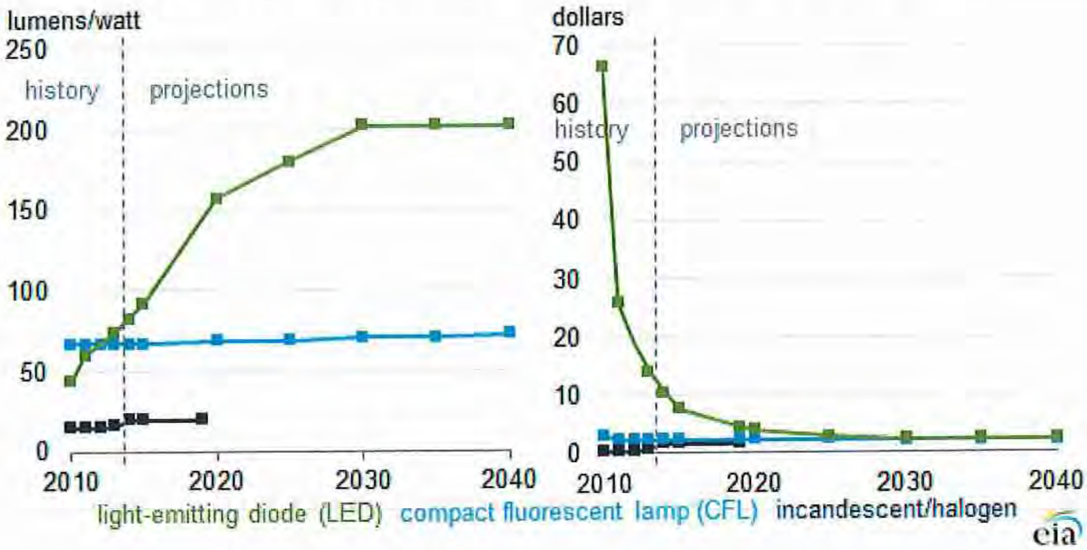



**Table 5. Average Lighting Efficacy by Sector, and Potential Reductions from LED Lighting**

| Market Sector | Residential | Commercial | Industrial |
|---|---|---|---|
| Current est. average market lighting efficacy, lm/w | 53 | 93 | 99 |
| % reduction in energy for same light level at 200 lm/w | 74% | 54% | 50% |

**Energy Controls and Information Systems.** As with LED lighting, there are programs that currently deliver both energy controls and information systems, but they are not fully represented in the 2013 and 2015 potential model efforts and represent opportunities for new initiatives to contribute towards higher savings. In general, opportunities for controls and information systems is largest in the following two areas.

- **Lighting Controls.** In addition to converting to LED lighting, recent studies have shown significant potential for lighting controls. The 2015 commercial saturation study[55] included

[55] California Commercial Saturation Survey. Itron Inc., August 2014 Table 5-82

an analysis of lighting controls indicating that 67% of light commercial buildings are controlled manually while 33% are operated with various other types of lighting controls. Lighting controls in commercial buildings can save an average of 20% of lighting energy.

- **Building Information & Energy Management Systems.** Various studies indicate that the penetration of Energy Information Systems (EIS) and Energy Management Systems (EMS) are low compared to potential applications, and new ways to combine and extract value from these systems are also emerging. Additionally, the past five years has seen the growth of many new companies and applications involving energy information. Favorable trends in information systems, controls technologies, and associated costs suggest that market penetration of these technologies could be much higher. A technical analysis supporting AB802[56] forecasts the potential to leverage the combined use of these EIS and EMS technologies (referred to in that study as 'Building Information & Energy Management Systems', or BIEMS) As noted in that study, benefits at the core of the BIEMS concept include:
    - ***Energy visualization.*** Energy visualization represents the most minimalistic version of BIEMS. It uses basic utility, sub-meter, and other collected data to provide a basic visualization of energy consumption, sometimes in real time depending on data availability and frequency.
    - ***Energy analytics.*** Energy analytics go beyond energy dashboards and utilizes energy-related data to analyze building-level energy consumption characteristics. These analytics engines can perform a wide variety of functions such as uncovering opportunities to improve efficiency while supporting benchmarking efforts.
    - ***Operations and Facility Management.*** Operations and facility management services help automate and track maintenance and repair action items, including the automation of a building's maintenance schedule while reconciling operational changes in equipment/control set points. Some platforms also assist in managing capital expenditures related to equipment and asset management or helping customers evaluate any available energy supply options, including analysis of demand response opportunities.
    - ***Continuous Commissioning and Self-Healing Buildings.*** Continuous commissioning is a specialized application that several BIEMS vendors currently offer. This is closely related to operations management and typically requires the application of fault detection and diagnostics-based algorithms that track individual controls and equipment performance on an ongoing basis against ideal parameters to detect anomalies in system performance while reporting on any variance in performance.

  Building level energy savings estimates for comprehensive controls range from 10% for small building to 5% for large buildings and current saturations are estimated to be 37% across all commercial building types, indicating that significant potential exist for programs that combine both EIS and EMS systems. Programs that offer BIEMS type solutions

[56] AB802 Technical Analysis. Potential Savings Analysis. Prepared for the California Public Utilities Commission by Navigant Consulting, Inc. March 16, 2016. Reference No.: 174655.

represent potential that is underrepresented in both the current offerings of PG&E programs and underrepresented in the past CPUC potential studies.

**Increased Use of Market Ready Funding and Financing Products.** A CCA may be an effective platform from which to increase awareness and use of a broad array of market ready funding and financing mechanisms, some of which are designed specifically to achieve sustainability goals. Expanding the use of these mechanisms has several benefits, including an existing market capacity to lend, along with the potential for very cost effective delivery of energy efficiency without the need for rebates or other financial incentives. In general, funding and financing may be defined in two categories including 1) infrastructure and public facilities projects and 2) customer market financing. The following provides a brief description of each, and a list of over 50 currently available financing and funding tools can be found in Appendix B:

- Infrastructure and Redevelopment Public Funding and Financing. These are the mechanisms that will be selected by city planners and financiers to accomplish large redevelopment and water projects and generally include grant funding, land based financing tools such as tax increment financing, and usage fees.
- Residential and non-residential funding and financing. These are the tools that will be used to implement sustainability projects in the residential and non-residential facilities that are included within priority areas, and community wide in both existing building and new construction applications through these mechanisms. These include commercial loan products such as home equity lines and utility on bill products, targeted federal agency products such as VA or HUD loans, state agency products such as SAFEBIDCO and COIN, and tax increment financing products such as PACE financing.

More aggressive use of these market ready funding and financing programs to implement sustainability projects may offer the opportunity for a CCA program that leverages private capital in lieu of rebates to achieve various County sustainability goals.

**High Opportunity Programs and Projects (HOPPs).** In October 30, 2015, an amended scoping memorandum expanded the 'Rolling Portfolios' proceeding scope to include the implementation of AB 802. It established a process specifically for addressing "High Opportunity Programs or Projects" (HOPPs). HOPPs expanded to target increased energy efficiency of existing buildings, including "stranded potential" via AB 802's new approaches to valuing and measuring savings. HOPPs are intended to focus on interventions (and associated intervention strategies and savings measurement regimes that program administrators could not previously undertake). The following outlines some of the HOPPs currently being proposed or deployed as pilot programs at the time of this analysis.

- **The Residential Pay-for-Performance (P4P) HOPP (PG&E).** This pilot seeks to develop a scalable model for residential retrofits that leverages rapidly emerging market actors and products while minimizing administrative and implementation costs. The program will seek out parties referred to as "Aggregators" who will either directly or through a network of contractors perform energy efficiency interventions in customers' homes with the goal of maximizing measureable savings. Aggregators may consist of existing energy efficiency market participants, such as Property Accessed Clean Energy (PACE) loan providers, smart thermostat vendors, vertically integrated contractors, program implementers, and/or new entrants to the California market. These Aggregators will compete for funding through Power Savings Agreements (PSA).

- **The Business Equipment Early Retirement HOPP (SDG&E).** This pilot is open to all business customers in the C/I/A segments with aging HVAC equipment. Some old inefficient equipment has been kept in service past its expected useful life. Customers often choose to repair, rather than replace, their aging equipment because the current rebates offered for such measures are insufficient to defray a meaningful portion of new equipment costs. Such existing equipment may be far below current code. The untapped savings represented by replacing an old inefficient unit with a new efficient one may be considered the stranded savings potential.
- **The Tiered Incentive Custom Calculated HOPP (SDG&E).** This pilot targets mid-sized to large-sized (above 200kW) non-residential customers with retrofit opportunities for large To-Code and Above Code energy savings. Tiered Incentives will target customers who have large To-Code and Above Code projects that have previously been rejected, or those with known equipment that has not been replaced due a lack of incentives. Historically, utilities have not been able to provide incentives for projects that yield only To-Code savings which has created stranded savings in these projects.

HOPP programs offer new opportunities for CCA's to participate in existing energy efficiency programs while also allowing program administrators added flexibility in program design and savings attribution. For example, the SDG&E multifamily HOPP may offer a template for Alameda county to serve it's middle and low income customers, while the PG&E Residential Pay-for-Performance HOPP may offer opportunities for the County to share in revenue earned by aggregators of PACE program savings operating within the County, thereby providing an incentive for the County to help drive and expand these programs.

In summary, the preceding discussion on energy efficiency potential indicates that;

- A review of energy sales and market characteristics indicate that estimates of energy efficiency potential for the overall PG&E service territory can be allocated to Alameda County in proportion to the County's share of PG&E total electricity sales, which is about 7.5%.
- An analysis of the potential study developed by the CPUC to assess the market potential from energy efficiency in PG&E service territory indicates that there is the potential for energy efficiency in Alameda County beyond what is being delivered by the current suite of energy efficiency programs operating in the county.
- A review of current and emerging energy efficiency technologies and innovative new programs designs indicate that it is possible to install higher levels of energy efficiency than has historically been achieved at cost-benefit thresholds that are acceptable under current CPUC guidelines.

## Current Funding Opportunities and Energy Efficiency Costs

CCA's have the opportunity use both electric and gas public purpose program funds to provide distributed energy resource programs to customers in a variety of ways. To access funds for electricity energy efficiency programs based on the most current CPUC guidance, including.[57]

Submit a plan, approved by its governing board, to the Commission for the administration of cost-effective energy efficiency and conservation programs for the aggregator's electric service customers that includes funding requirements, a program description, a cost-effectiveness analysis, and the duration of the program. To be approved, the submitted plan must satisfy the following criteria:

- Is consistent with the goals of Public Utilities Code Section 399.4.[58]
- Advances the public interest in maximizing cost-effective electricity savings and related benefits.
- Accommodates the need for broader statewide or regional programs.
- Includes audit and reporting requirements consistent with the audit and reporting requirements established by the commission pursuant to this section.
- Includes evaluation, measurement, and verification protocols established by the community choice aggregator.
- Includes performance metrics regarding the community choice aggregator's achievement of the selected objectives.

Upon submission of a successful plan, A CCA may elect to become the administrator of funds collected from the aggregator's electric service customers and collected through a nonbypassable charge authorized by the Commission may be accessed, except those funds collected for broader statewide and regional programs authorized by the commission. For CCAs electing to become

[57] As defined in Rulemaking 09-11-014

[58] Public Utilities Code Section 399.4 requires;

a. The CPUC shall continue to administer cost-effective energy efficiency programs authorized pursuant to existing statutory authority.

b. The term energy efficiency includes, but is not limited to, cost-effective activities to achieve peak load reduction that improve end-use efficiency, lower customers' bills, and reduce system needs.

c. Any rebates or incentives offered by a public utility for an energy efficiency improvement or installation of energy efficient components, equipment, or appliances in buildings shall be provided only if the recipient of the rebate or incentive certifies that the improvement or installation has complied with any applicable permitting requirements and, if a contractor performed the installation or improvement, that the contractor holds the appropriate license for the work performed.

d. The commission, in evaluating energy efficiency investments under its existing statutory authority, shall also ensure that local and regional interests, multifamily dwellings, and energy service industry capabilities are incorporated into program portfolio design and that local governments, community-based organizations, and energy efficiency service providers are encouraged to participate in program implementation where appropriate.

program administrators, the formula used to estimate the budget available for program activities is defined as;

> *CCA maximum funding = Total electricity energy efficiency nonbypassable charge collections from the CCA's customers – (total electricity energy efficiency nonbypassable charge collections from the CCA's customers * % of the applicable IOU portfolio budget that was dedicated to statewide and regional programs in the most recently authorized program cycle).*

For fiscal year 2015 the CPUC reports[59] that the total cost of customer programs for electricity indicatives in the PG&E service territory to be approximately $1.2B, as shown in Table 6, including various subprograms. Of these customer program funds, the total electricity energy efficiency nonbypassable charges referenced in Rulemaking 09-11-014 are approximately $351M (29%) are allocated for energy efficiency (EE) programs. Based on PG&E sales to Alameda County and as discussed previously, it can be assumed that approximately 7.5% of these funds, or $26.6M annually, are provided by sales of electricity to residents of Alameda County.[60]

**Table 6. Allocation of Electric and Gas Utility Cost, April 2016**

| | Program Costs ($000) | |
|---|---|---|
| Customer Program | PG&E | Alameda (estimated) |
| Energy Efficiency | $351,311 | $26,629 |
| Demand Response | $63,978 | $4,850 |
| California Solar Initiative | $94,000 | $7,125 |
| Self-Generation Incentive Program | $29,616 | $2,245 |
| CARE Subsidy | $565,541 | $42,868 |
| CARE Administrative Expenses | $12,794 | $970 |
| Low Income Energy Efficiency | $95,089 | $7,208 |
| Total | $1,212,329 | $91,895 |

The maximum funding equation provided in R.09-11-014 does not define the amount of the applicable IOU portfolio budget that is dedicated to statewide and regional programs, however it is estimated to be approximately 85% of available budget, based on a review of decisions addressing the approved 2015 Marin Clean Energy program portfolio. This leaves 15% of funds available for CCA administered energy efficiency programs. **Error! Reference source not**

[59] Electric and Gas Utility Cost Report. Public Utilities Code Section 913 Report to the Governor and Legislature, April 2016.

[60] Based on an analysis of PG&E electricity sales within Alameda County for 2013 and 2014 and CEC data on Alameda County and PG&E electricity usage.

**found.** shows that this is approximately \$3.9M for programs administered by a CCA to all Alameda County residents, including PG&E customers, or \$3.5M if these programs serve only CCA customers, assuming a 15% opt-out rate.

**Table 7. Annual Funding Models for Non-bypassable Electric Charges**

| Annual Funding Models for Non-bypassable Electric Charges | Estimated Value |
|---|---|
| Program Administrator - CCA and PG&E customers | \$3,941,000 |
| Program Administrator - CCA customer only | \$3,350,000 |

Other funds would also likely be available to help administer energy efficiency programs. An inexhaustive list of other potential funding sources are listed below. This analysis did not estimate the potential value of these funds.

- Funds from Non-bypassable Gas Charges – CPUC Decision D.14-10-046 allows CCA's to administer programs that include funds collected from natural gas customer. This analysis did not estimate the value of these funds.
- Income from CCA Operations. Income generated through CCA operations may be used to fund customer programs.
- Funding secured by StopWaste's Energy Council on behalf of any potential relationship between its member agencies and a CCA.
- Increased funding through the expansion of the CCA territory. Under current regulations it is allowed for a CCA to define its service territory more broadly than a city or county. As such, the rules that define the funding for Alameda County residents would apply to new participants in a CCA and so provide incremental program funding. For example, in 2015 Marin Clean Energy began serving customer in Contra Costa County and has increased its available program funding as a result of this enrollment.

CCA's may also choose to not administer programs. CAs' that choose to be non-administrators have the following authority as defined in R.09-11-014;

> *If a community choice aggregator is not the administrator of energy efficiency and conservation programs for which its customers are eligible, the commission shall require the administrator of cost-effective energy efficiency and conservation programs to direct a proportional share of its approved energy efficiency program activities for which the community choice aggregator's customers are eligible, to the community choice aggregator's territory without regard to customer class.*

and

*The commission shall also direct the administrator to work with the community choice aggregator, to provide advance information where appropriate about the likely impacts of energy efficiency programs and to accommodate any unique community program needs by placing more, or less, emphasis on particular approved programs to the extent that these special shifts in emphasis in no way diminish the effectiveness of broader statewide or regional programs.*

Assuming that a 'proportional share of its approved energy efficiency program activities for which the community choice aggregator's customers are eligible' refers to funds collected, this is estimated to average approximately $26M annually for 2013 and 2014.

## Current Costs of Energy Efficiency

The savings potential for energy efficiency programs operated by an Alameda County CCA were estimated based on the amount of funding available and the unit price of energy efficiency ($/kWh). The MRW team reviewed program savings goals and program budget data for the 2015 PG&E portfolio to identify unit costs and found a broad range of costs depending on the nature of the program and whether or not the program saved only electricity, or also had natural gas savings.

Figure 6 provides a cost of supply curves which shows how much energy efficiency is available in the PG&E's 2015 portfolio, and at what price per first year gross kWh. The cost curve changes as new technologies become available, such as high efficiency LED lighting, or as new delivery models emerge, such as PACE financing. The cost curve also changes as program administrators find more efficient ways to deliver services and new methods to engage customers come to market, such as big data applications that use smart meter data to help identify customers and facilities with high opportunity for savings. Additionally, **Error! Reference source not found.** provides a summary of select program that are representative of the range of markets and program costs most likely to be represented in energy efficiency programs administered by an Alameda CCA.

**Figure 6. Normalized First Year KWh Savings Equivalent Costs for the 2015 PG&E Portfolio**

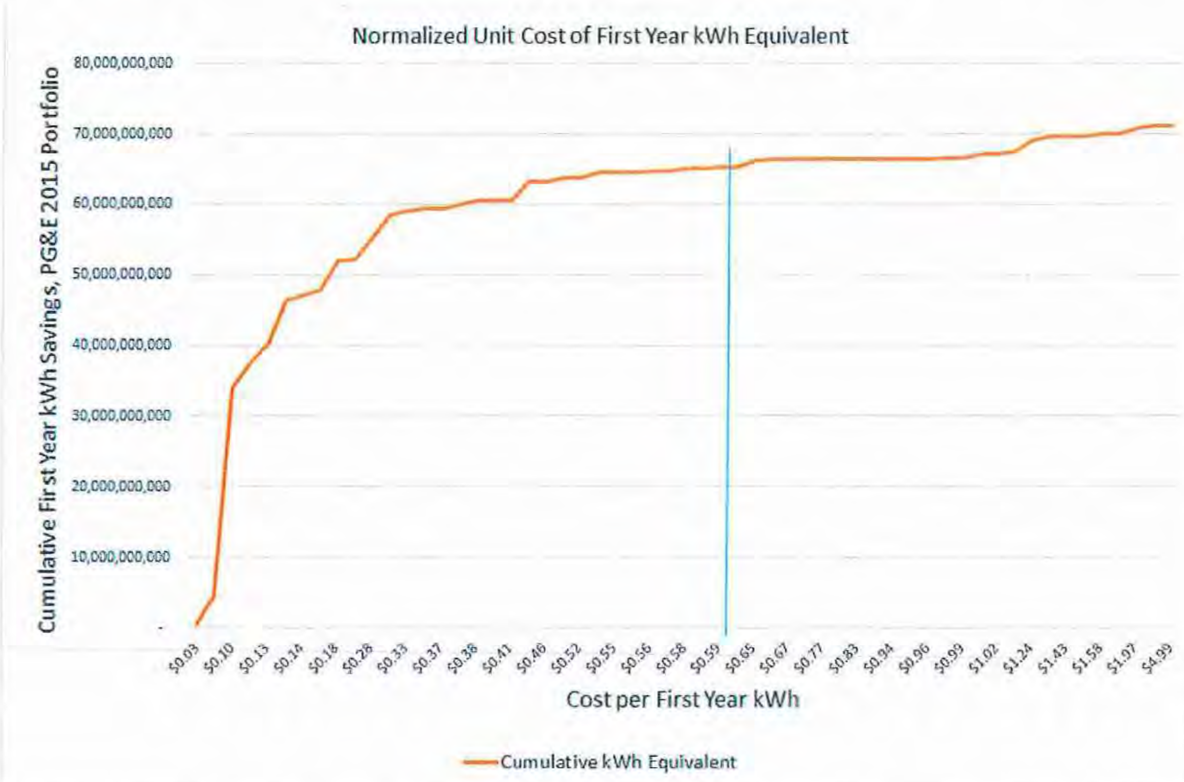



**Table 8. Select Unit Costs for Energy Efficiency ($/ net kWh)**

| Program Admin | Sub-Program Name | Percent Program Savings that are Electric | Cost Per First Year Net kWh Equivalent |
|---|---|---|---|
| PG&E | Commercial Energy Advisor | 18% | $0.18 |
| MCE | MEA 02 - Small Commercial | 79% | $0.37 |
| PG&E | Lighting Programs Total | 100% | $0.38 |
| MCE | MEA01 2013-14 MF - Multifamily | 36% | $0.59 |
| PG&E | East Bay | 93% | $0.59 |
| Third Party | RightLights | 100% | $0.75 |
| PG&E | Energy Savers | 100% | $0.81 |
| Third Party | Energy Fitness Program | 100% | $0.84 |

Based on this analysis, a cost of $0.61 per net first year kWh was used to represent the current unit cost of energy efficiency. As discussed in the following section, this unit cost was subsequently multiplied by the available funding to determine how much EE will be achieved in Alameda County, based on the previous assumptions that both the technical and economic market potential exists.

## Remi Model Inputs

Based on the proceeding discussions regarding the availability of energy efficiency in Alameda County, and the potential for funding and associated costs, the MRW team developed the inputs for the REMI model that reflects several overarching assumptions;

- Technical, economic and market potential for energy efficiency is available in the County, including markets and technologies that are likely underrepresented in existing program offerings and offer the opportunity for new market interventions to achieve savings that are incremental to the goals currently established by the CPUC for PG&E.
- Regulators have defined the funding mechanisms for CCA's to administer energy efficiency programs, and this analysis used a conservative approach to forecast funding for energy efficiency over the MRW analysis timeframe. additional funding may be developed from multiple other source that can be used to develop additional energy savings.

Table 9 provides a summary of the factors used in the energy efficiency analysis used to develop inputs for the REMI Model, and Table 10 provides additional definitions intended to provide further transparency and clarity into the efficiency analysis.

**Table 9. Factors Used in the Energy Efficiency Analysis**

| Analysis Factors | Value |
|---|---|
| First year available EE portfolio budget | $3,350,453 |
| Non-Union Labor Cost | $67.26 |
| Union Labor Cost | $79.37 |
| Average Labor Cost | $73.32 |
| Ratio of union hourly cot to non-union hourly costs | 1.18 |
| Incentives as % of total program costs | 51.43% |
| % of portfolio budget where program labor is union | 20.22% |
| Labor as a % of total measure cost | 27.98% |
| Incentives as % of total measure cost | 21.43% |
| Annual Energy Growth Rates (%)[61] | 0.98% |
| PGE kW/kWh ratio | 0.0158% |
| Average cost per EE program staff | $100,000 |
| Labor as a percent of program spending | 70.00% |
| Ave PG&E program cost per first year annual gross kWh | $0.42 |
| Portfolio NTG | 0.7 |
| Average PGC $/kWh | $0.61 |
| % of Program Budget - Incentives which are Direct Install Labor | 65.65% |
| Incentive % total program budget - Residential | 33.05% |
| Incentive % total program budget - Commercial | 43.44% |
| Incentive % total program budget - Industrial | 15.51% |
| Incentive % total program budget - Municipal | 8.01% |

[61] California Energy Demand 2015 Revised - Mid Demand

**Table 10. Definitions Used in the Efficiency Analysis**

| | |
|---|---|
| Budget Growth Factor | Assumed change in annual budget available for Alameda CCA EE program based forecast growth in electric energy consumption from the 2015 IEPR mid-case |
| Baseline Budget | Assumed annual budget available for Alameda CCA EE program based on current PG&E portfolio costs and current CPUC guidelines for allocation of public goods charges available for CCA programs |
| Annual incremental GWh savings | Average annual potential GWh savings based on weighted average cost per GWh for relevant programs in the 2015 PG&E EE program portfolio |
| Annual incremental MW savings | Average annual potential MW savings based on weighted average kW/kWh ratio for relevant programs in the 2015 PG&E EE program portfolio |
| Non-union Labor (Man-hours) | Annual non-union labor hours to install energy efficiency projects represented in the annual incremental GWh savings estimate |
| Union Labor (Man-hours) | Annual union labor hours to install energy efficiency projects represented in the annual incremental GWh savings estimate |
| Total Labor (Man-hours) | Total union and non-union labor hours |
| Value of Labor ($) | Total dollar value of labor based on union and non-union rates |
| Value of Products Installed ($) | Total dollar value of products installed. This will be:<br>• Incremental equipment cost for replace on burnout projects where the customer must do the project and where efficient equipment has incremental costs above code compliant equipment<br>• Full cost for retrofit projects where customer elects to do the project and installs above code equipment |
| Customer Out of Pocket ($) | Total dollar value of customer out-of-pocket costs for products installed. This will be:<br>• No out of pocket costs for direct install projects<br>• Cost of addition funds required above any utility/CCA equipment rebate incentives |
| Annual Invest Needed | Budget (Admin + M&O - Incentives) + Material + Labor, or customer out of packet plus program spending |
| Installation Labor | Trade Labor (Union + Non Union) + Direct Installation Labor |
| **Development Timeline** | • 3 years to establish core CCA operation<br>• 1 year for filing and development of EE programs, launch in 2021 |

**Energy and Demand Savings Potential**

The MRW teams defined the level of energy efficiency input into the REMI model would be based on incremental savings that would result from CCA administered energy efficiency programs, in excess of the levels of energy efficiency savings targeted by current PG&E initiatives. The amount of CCA program potential was calculated based on funding available and the cost of energy efficiency using the following inputs;

- Available annual budget for energy efficacy programs is based on the maximum funding equation provided in R.09-11-014, and assuming programs are administered only to CCA customers. As discussed in **Error! Reference source not found.**, this represents approximately $3.5M annually.
- The cost of energy efficiency programs most likely to be offered under and a CCA would be $0.61 per net first year kWh.
- The savings from energy efficiency during the forecast horizon would grow at a rate consistent with expected annual energy demand as defined in the 2015 CEC IEPR demand forecast.[62]
- Demand savings would be consistent with the ratio of demand to energy savings achieved by the programs most likely to be offered by a CCA as presented in **Error! Reference source not found.**.

Based on this methodology, **Error! Reference source not found.** provides a summary of REMI model energy and demand savings inputs.

**Table 11. REMI Model Energy and Demand Savings Inputs**

| Year | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Annual incremental energy savings (GWh)** | 5.7 | 5.8 | 5.9 | 5.9 | 6.0 | 6.0 | 6.1 | 6.1 | 6.2 | 6.3 |
| **Annual incremental demand savings (MW)** | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |

**Economic Activity Related to Energy Efficiency**

Based on the energy efficiency analysis factors and definitions provides in Table 9 and Table 10 respectively, Table 12 provides a summary of the economic inputs from the REMI model that results from CCA administration of energy efficiency programs as defined above.

[62] Form 1.1 - PGE Planning Area California Energy Demand 2015 Revised - Mid Demand Case. Electricity Consumption by Sector (GWh)

Table 12. REMI Model Economic Inputs

| Economic Activity | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Annual Invest Needed** | $13.3 | $13.7 | $14.0 | $14.4 | $14.8 | $15.2 | $15.6 | $16.0 | $16.4 | $16.9 |
| **Installation Labor** | $3.7 | $3.8 | $3.9 | $4.0 | $4.1 | $4.2 | $4.3 | $4.5 | $4.6 | $4.7 |
| **Customer Out of Pocket** | $9.6 | $9.8 | $10.1 | $10.3 | $10.6 | $10.9 | $11.2 | $11.5 | $11.8 | $12.1 |
| **Value of Products Installed** | $9.0 | $9.2 | $9.5 | $9.7 | $10.0 | $10.2 | $10.5 | $10.8 | $11.1 | $11.4 |

## Appendix 1. PG&E Programs Active in Alameda County

Table shows 2015 programs, including total PG&E service territory or statewide budgets, and capacity and energy goals, including BayREN program activities. The 'X' in the column title 'Active in Alameda County' indicates the program is either activity providing financial incentives or technical support for activities within Alameda County. With the exception of the opportunities noted earlier, these programs cover most energy efficiency measures across all market sectors, including;

- Codes & standards programs intended to enhance compliance and promote new, more aggressive codes in select jurisdictions;
- Commercial sector programs that include deemed and custom incentives as well as technical support;
- Third party programs administered by PG&E but implemented through various contractors that are target specific technology applications or specific market segments, such as refineries, health care providers, or schools;
- Residential energy efficiency programs providing rebates for the multifamily market, HVAC and whole house solution for the single family market and support for residential new construction
- Government partnership programs that include support for local governments through the East Bay Energy Watch program, as well as various institutional programs focused on universities and community colleges.
- Industrial and agricultural programs providing provide financial incentives and technical support various statewide and 3rd party, segment specific industries.
- Emerging technologies programs that support the integration of emerging technologies.

| Program / Sub-Program | Active in Alameda County | Sum of Total Incentive | Sum of Total Budget | Sum of Goals therm | Sum of Goals kWh | Sum of Goals kW |
|---|---|---|---|---|---|---|
| **Codes & Standards Programs Total** | | **$0** | **$16,496,433** | **1,105,275** | **282,613,013** | **44,188** |
| Appliance Standards Advocacy | | $0 | $2,396,375 | 0 | 0 | 0 |
| Compliance Improvement | x | $0 | $2,094,222 | 0 | 0 | 0 |
| Reach Codes | x | $0 | $628,267 | 0 | 0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2015 C&S | | $0 | $8,248,217 | 1,105,275 | 282,613,013 | 44,188 |
| Building Codes Advocacy | x | $0 | $2,396,375 | 0 | 0 | 0 |
| Planning and Coordination | | $0 | $732,978 | 0 | 0 | 0 |
| **Commercial Programs Total** | | **$41,866,061** | **$76,775,328** | **4,817,546** | **171,723,947** | **30,271** |
| Savings by Design | x | $5,844,020 | $11,369,534 | 116,869 | 24,426,648 | 6,803 |
| Commercial Calculated Incentives | x | $9,279,579 | $24,269,550 | 2,415,252 | 69,427,959 | 7,053 |
| Commercial Deemed Incentives | x | $9,916,156 | $17,385,210 | 858,364 | 63,124,601 | 11,187 |
| Commercial Energy Advisor | x | $3,774,215 | $5,475,917 | 1,217,783 | 7,960,408 | 3,104 |
| Commercial HVAC | x | $13,052,092 | $17,855,076 | 209,278 | 6,784,331 | 2,124 |
| Commercial Continuous Energy Improvement | x | $0 | $420,042 | 0 | 0 | 0 |
| **Third Party** | | **$37,126,216** | **$89,088,656** | **3,644,336** | **158,670,368** | **26,223** |
| Refinery Energy Efficiency Program | x | $1,350,924 | $2,784,375 | 1,100,151 | 3,100,902 | 451 |
| California New Homes Multifamily | x | $2,295,459 | $4,218,571 | 120,000 | 1,720,000 | 1,316 |
| Enhance Time Delay Relay | x | $556,009 | $1,065,230 | -23 | 918,766 | 1,485 |
| Direct Install for Manufactured and Mobile Homes | x | $3,300,448 | $4,541,979 | -32,220 | 6,539,901 | 3,900 |
| Monitoring-Based Persistence Commissioning | x | $609,275 | $2,188,015 | 180,391 | 3,182,583 | 208 |
| LodgingSavers | x | $2,125,000 | $4,769,442 | -13 | 7,189,320 | 1,598 |

| | | | | | | |
|---|---|---|---|---|---|---|
| School Energy Efficiency | x | $1,259,822 | $3,445,459 | 198,645 | 3,345,368 | 325 |
| Energy Fitness Program | x | $1,100,000 | $2,706,116 | -14,461 | 4,583,332 | 833 |
| Energy Savers | x | $550,000 | $1,323,747 | -5,352 | 2,334,528 | 389 |
| RightLights | x | $2,350,000 | $5,075,125 | -26,552 | 9,723,911 | 1,441 |
| Furniture Store Energy Efficiency | x | $934,283 | $1,544,734 | -23,844 | 4,011,500 | 846 |
| LED Accelerator | x | $1,473,572 | $2,722,282 | -8,085 | 4,664,841 | 954 |
| Casino Green | x | $500,000 | $1,374,085 | 8,055 | 1,762,414 | 347 |
| Healthcare Energy Efficiency Program | x | $323,517 | $770,461 | 65,152 | 1,323,900 | 189 |
| K-12 Private Schools and Colleges Audit Retro | x | $1,256,288 | $2,068,748 | -23,486 | 2,896,447 | 255 |
| Innovative Designs for Energy Efficiency Approaches (IDEEA) | x | $2,631,321 | $7,924,297 | 185,261 | 5,932,977 | 521 |
| Air Care Plus | x | $1,006,857 | $3,471,776 | 371 | 9,024,156 | 902 |
| Boiler Energy Efficiency Program | x | $641,630 | $1,945,225 | 729,383 | 34,331 | 16 |
| EnergySmart Grocer | x | $1,964,682 | $6,637,581 | 15,746 | 17,685,129 | 1,847 |
| Industrial Recommissioning Program | x | $310,000 | $1,339,090 | 0 | 2,982,339 | 247 |
| California Wastewater Process Optimization | x | $250,000 | $953,641 | 0 | 1,774,954 | 204 |
| Energy Efficiency Services for Oil Production | x | $1,980,782 | $4,447,949 | 0 | 15,650,820 | 1,389 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Heavy Industry Energy Efficiency Program | x | $4,710,923 | $12,041,118 | 950,064 | 27,582,099 | 3,727 |
| Industrial Compressed Air Program | x | $551,654 | $1,661,321 | 0 | 5,109,111 | 516 |
| Dairy Industry Resource Advantage Pgm | x | $502,246 | $1,522,197 | -4,826 | 2,261,157 | 484 |
| Process Wastewater Treatment EM Pgm for Ag Food Processing | x | $364,855 | $1,015,922 | 0 | 2,166,210 | 224 |
| Dairy Energy Efficiency Program | x | $116,344 | $427,467 | -9 | 649,719 | 55 |
| Industrial Refrigeration Performance Plus | x | $917,842 | $1,562,711 | 0 | 3,850,895 | 347 |
| Light Exchange Program | x | $283,295 | $863,570 | -25 | 860,177 | 210 |
| Wine Industry Efficiency Solutions | x | $475,400 | $1,675,216 | 29,992 | 3,362,430 | 554 |
| Comprehensive Food Process Audit & Resource Efficiency Pgm | x | $433,789 | $1,001,206 | 200,020 | 2,446,152 | 443 |
| **Residential Energy Efficiency Programs Total** | | **$33,850,892** | **$60,142,415** | **2,706,366** | **128,508,610** | **12,925** |
| Residential Energy Advisor | x | $11,026,625 | $13,316,458 | 1,800,000 | 90,000,012 | 0 |
| Plug Load and Appliances | x | $7,233,850 | $17,791,846 | 223,735 | 32,476,767 | 8,129 |
| Multifamily Energy Efficiency Rebates Program | x | $362,547 | $1,685,302 | 90,715 | 981,794 | 94 |
| Whole Home Upgrade Program | x | $7,537,049 | $13,672,077 | 429,482 | 3,159,402 | 2,523 |
| Residential New Construction | x | $2,554,476 | $4,422,870 | 114,696 | 639,133 | 1,306 |
| Residential HVAC | x | $5,136,345 | $9,253,861 | 47,737 | 1,251,503 | 874 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Government Partnership Programs Total** | | **$30,735,492** | **$70,026,290** | **1,481,091** | **107,205,951** | **12,766** |
| California Community Colleges | x | $1,536,198 | $2,249,794 | 163,439 | 3,679,913 | 505 |
| University of California/California State University | x | $6,996,526 | $12,363,959 | 744,372 | 16,759,951 | 2,302 |
| State of California | x | $1,777,057 | $2,294,475 | 189,064 | 4,256,884 | 585 |
| Department of Corrections and Rehabilitation | x | $1,597,166 | $3,099,187 | 169,925 | 3,825,960 | 525 |
| Local Government Energy Action Resources (LGEAR) | x | $1,926,566 | $5,446,566 | 26,009 | 7,406,533 | 856 |
| East Bay | x | $5,187,765 | $9,685,962 | 56,197 | 21,652,559 | 2,487 |
| **Agricultural Programs Total** | | **$8,330,403** | **$17,449,635** | **1,690,030** | **70,047,080** | **20,515** |
| Agricultural Calculated Incentives | x | $4,231,087 | $9,351,902 | 1,501,966 | 24,661,230 | 5,242 |
| Agricultural Deemed Incentives | x | $1,965,211 | $3,583,046 | 152,460 | 21,486,589 | 11,904 |
| Agricultural Energy Advisor | x | $2,134,105 | $4,049,572 | 35,604 | 23,899,261 | 3,369 |
| Agricultural Continuous Energy Improvement | x | $0 | $465,115 | 0 | 0 | 0 |
| **Lighting Programs Total** | | **$7,799,802** | **$12,856,179** | **-850,920** | **40,081,866** | **5,344** |
| Primary Lighting | x | $6,978,299 | $10,710,998 | -850,920 | 40,081,866 | 5,344 |
| Lighting Innovation | x | $821,503 | $1,496,016 | 0 | 0 | 0 |
| Lighting Market Transformation | x | $0 | $649,166 | 0 | 0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Industrial Programs Total** | | **$15,468,886** | **$24,995,292** | **8,842,652** | **33,399,496** | **4,785** |
| Industrial Calculated Incentives | x | $13,302,782 | $20,361,087 | 8,591,960 | 27,987,597 | 3,515 |
| Industrial Deemed Incentives | x | $538,604 | $1,091,268 | 201,525 | 5,053,897 | 1,057 |
| Industrial Energy Advisor | x | $1,627,500 | $3,031,540 | 49,167 | 358,002 | 213 |
| Industrial Continuous Energy Improvement | x | $0 | $511,398 | 0 | 0 | 0 |
| **BayRen** | | **$6,815,663** | **$11,930,137** | **315,403** | **2,360,400** | **825** |
| Single Family Residential | x | $2,980,710 | $4,840,886 | 81,794 | 205,724 | 521 |
| Multifamily Residential | x | $3,750,000 | $6,476,600 | 175,391 | 1,769,656 | 175 |
| Commercial PACE | x | $84,953 | $251,505 | 3,096 | 144,540 | 108 |
| Pay As You Save (Green Hayward PAYS) | x | $0 | $361,146 | 55,122 | 240,480 | 21 |
| **Emerging Technologies Programs Total** | | **$0** | **$5,959,297** | **0** | **0** | **0** |
| Technology Development Support | x | $0 | $417,151 | 0 | 0 | 0 |
| Technology Assessments | x | $0 | $2,860,463 | 0 | 0 | 0 |
| Technology Introduction Support | x | $0 | $2,681,684 | 0 | 0 | 0 |
| **Grand Total** | | **$182,447,885** | **$386,918,729** | **23,959,687** | **1,000,870,238** | **158,063** |

## Appendix 2. Market Ready Funding and Financing Mechanisms

Market ready funding and financing mechanisms that may be used to drive energy efficiency projects in Alameda County may be defined in two categories of funding and financing mechanisms including 1) infrastructure and public facilities projects and 2) residential and non-residential market sector financing. A partial list of these mechanisms to be considered;

1. Infrastructure and Redevelopment Public Funding and Financing. These are the mechanisms that will be selected by city planners and financiers to accomplish large redevelopment and water projects and include;
   - State grant funding including
     - Greenhouse Gas Reduction Fund programs
     - Environmental Enhancement and Mitigation (EEM) Program
     - CalConserve Water Use Efficiency Revolving Fund Loan Program
   - Land-based financing tools
     - Energy Development Districts (EDD)
     - Benefit Assessment Districts
     - Enhanced Infrastructure Funding Districts (EIFD)
     - Community Facilities Districts (CFDs)
     - Tax Increment Financing,
     - California Community Capital Collaborative
   - Other Fresno propositions and usage fees
     - Proposition M Sustainable Transportation funds
2. Residential and non-residential facilities funding and financing. These are the tools that will be used to implement sustainability projects in the residential and non-residential facilities that are included within priority areas, and community wide in both existing building and new constructions through these mechanisms;
   - Non-utility private and public funding and financing
     - Small Business Investment Companies (SBIC/SBA)
     - Tax-Exempt Industrial Development Bonds
     - California Organized Investment Networks (COIN)
     - Fresno Community Development Financial Institutions (CDFI)
     - Community Investment Note
     - State Assistance Fund for Enterprise / Business and Industrial Development Corporation (SAFE-BIDCO)
     - Socially Responsible Investors (SRI)
     - Residential and Commercial PACE
     - ChargePoint® Net+ Purchase EV Charge Station Financing
     - Corporate Investment in Shared Value
     - Social Impact Bonds
     - Community Currency and Time Banks
     - Solar $mart Home Equity Line of Credit
     - Home Equity Loan
     - Home Equity Line of Credit

- SBA Loan Programs including;
    - SBA Green 504 Loans
    - 7(a) Loans
    - 504 Loans
    - Rural Business Investment Program (RBIP)
- Housing and Urban Development (HUD) instruments including;
    - Choice Neighborhoods Planning and Implementation Grants program
    - Federal Housing Administration (FHA) 203(k) Mortgage program
    - Section 207/223(f) mortgage insurance
    - Section 202 Direct Loan Program for Housing for the Elderly or Handicapped
    - Section 3 program
- Veteran Administration (VA) instruments including;
    - VA Home Purchase Loans
    - VA Interest Rate Reduction Refinance Loans (IRRRL)
    - Specially Adapted Housing (SAH) Grants
    - Special Housing Adaptation (SHA) Grants
    - Chapter 6 Home Loan Guaranty

- Utility and CAEATFA/CHEEF funding and financings opportunities including;
    - IOU statewide and 3rd party rebate programs
    - Low income ESA
    - On-bill financing (pilot)
    - EUC and Flex Path
    - Small Business Lease Program (pilot)

## MEMORANDUM

To: Alameda County Community Choice Aggregation (CCA) Steering Committee

From: Mark Fulmer

Subject: Responses to Comments on the Feasibility Study

Date: June 29, 3016

MRW & Associates (MRW) released its CCA Feasibility Study report to the Steering Committee at its June 1, 2016 meeting. A number of Steering Committee members provided written comments and questions on the report (which are attached to this memo). The following are MRW's responses to those questions and comments.

**Pleasanton**

1. ***Key risks:*** The ranges of risks we used we think were appropriate. In any given year, the variable might be outside the range assumed, but on average we think the range is reasonable based on historical experience. Trying to predict opt-outs as a function of rate differentials is beyond the scope of the study. That said, there have been times in the past when MCE Clean Energy had rates that were higher than PG&E but there was no discernable change in the opt-out rates.
2. ***A high local renewables case:*** A high local renewables case, which assumes that 50% of the renewables requirement of the CCA would be developed in Alameda County, is currently under development and will be included as an addendum to the report.
3. ***PCIA risk.*** MRW agrees with the recommended strategy for dealing with the PCIA (collaborating with the other CCAs) and will include it in the risk assessment section.
4. ***Forecast:*** The forecast is from the California Energy Commission and is consistent with other long-run forecasts.
5. ***Rate analysis from a customer perspective:*** The analysis compares customers' rates with the Alameda CCA versus PG&E. It is not clear what additional analyses is desired.
6. ***Renewable premiums:*** MRW endeavored to be realistic yet conservative in its renewable cost estimates and based much of its analysis on renewable energy costs on actual contract prices that have been made available in the market. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low. By being conservative, the CCA has a higher likelihood of obtaining renewable contracts at a lower-than-anticipated pricing.
7. ***Balance sheet modeling of the sensitivity cases:*** The impacts on the balance sheet and reserves of the sensitivity cases were calculated in all of the sensitivity cases, but for the sake of length not included in the report. In no case but the "stress" were there any cash flow problems from the CCA point of view.

MRW generally concurs with the recommendations for further investigation, but note that they are beyond the scope of the feasibility study.

**Hayward**

***Please add to Chapter 3 information about anticipated rates for large and small commercial customers.*** Anticipated rates for all classes are included in Appendix A.

**Berkeley Climate Action Committee**

1. ***Overstates costs of small solar*:** MRW endeavored to be realistic yet conservative in its renewable cost estimates and based much of its analysis on renewable energy costs on actual contract prices that have been made available in the market. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low. By being conservative, the CCA has a likelihood of obtaining renewable contracts at a lower-than-anticipated pricing.
2. ***Include a case with Community Solar:*** Modeling an explicit Community Solar program is outside the scope of the feasibility study. This of course does not mean that one is infeasible or should not be pursued; only that it was outside of the major variables needed to demonstrate the feasibility (or infeasibly) of community choice energy in Alameda County. It can be assumed, however, that any Community Solar program pricing would be similar to any other type of solar contract of similar size. It would seem, therefore, that in the study we could include a descriptive paragraph on Community Solar programs and say that the programmatic details would be developed by the CCA program after launch.
3. ***Energy efficiency estimate is too low***: The analysis was based on current funding limitations from the CPUC. Additional amounts can be achieved if the CCA chooses to using any incremental revenues for energy efficiency rather than bill savings or renewables.

**Charles Rosselle**

1. ***Competition among CCAs for limited carbon-free resources.*** We agree that this could become an issue, and will add some discussion in the risks section.
2. ***Upward pressure on the PCIA form many CCAs:*** This issue is discussed on page 49 of the report.

The remaining points are thoughtful and should be kept in mind by the JPA and CCA planners if the EBCE moves forward.

**Albany Sustainability Committee**

1. ***Compare historic PG&E Rates to existing CCAs.*** A comparison will be provided if historic CCA rates prove readily available.
2. ***Address potential curtailment of CCA solar PV projects by the CAISO.*** The impacts of potential curtailment are acknowledged in Study. See the discussion starting at the bottom of page 15 and page 48.

3. ***Replace Diablo Canyon with energy efficiency, storage and renewables***. First, the base case assumes that Diablo Canyon (DC) would be shut, but replaced with gas-fired resources. While PG&E recently announced it would close DC and replace it with non-fossil resources, there are no details available (including what the rate implications of that path might be). A detailed plan will be decided at the CPUC in the Long Term Procurement Plan dockets. For a press release, there is no way they can say what they'll actually do, so they might as well put the best spin on is as they can—more renewables/EE. Second. Given that DC is a 2,000 MW baseload plant, simply replacing it with just (intermittent) solar and wind and EE can't be done without a great deal of storage. The feasibility of such an approach will depend on how much storage costs come down in the next several years. Certainly as of today, having 2,000 MW of renewables combined with large amounts of storage would cause rates to increase dramatically – thus, it's reasonable to assume that a large portion of that 2,000 MW would be replaced with fossil resources.

   Qualitatively, if we replaced DC with storage, energy efficiency and renewables, the net result would be PG&E costs that are between the base PG&E cost and the Diablo Canyon Relicense cost *(really? I would think costs would be higher if you have all that storage)*, but with PG&E GHG emissions that would be significantly lower than the PG&E base case (i.e., the big jump up on PG&E GHG emissions in 2025 would not occur).

**IBEW (June 18)**

***General problem with approach: A stochastic (probabilistic) approach preferred over the scenario (snapshot) approach taken.***

A stochastic approach requires one to identify the key inputs to an analysis, assign a probabilistic distribution to each of the values, and then run numerous scenarios to get the "average" outcome as well as the distribution of outcomes. This allows one to identify not only the average expected outcome but the probability of a negative outcome (i.e., the CCA not achieving rates lower than PG&E).

While there is an appeal to this method, it requires significantly more resources that were provided for in this study. Furthermore, it requires analysts to make critical assumptions concerning the probabilistic distribution of the values. This makes the analysis significantly more opaque and difficult to verify (was the distribution function reasonable?) without necessarily adding accuracy.

The snapshot approach allows the study to select outlying values for key variables and see if they cause undue burdens on the program. This allows the JPA or other planners to take into account these variables and implement actions to contain them. Thus, overall, we think that a probabilistic approach would yield a significant increase in cost without adding any greater level of accuracy in the forecasts. It should also be noted that no other CCA technical studies have undertaken such analyses.

1. ***A&G assumptions***: The values used from Sonoma Clean Power were consistent with other CCA feasibility studies. The fact that Sonoma has (nor has not) achieved their goals

in the relatively short time they have been in existence does not mean that they have underspent. It should also be noted that SCP has more than 100 MW of new renewable energy projects in its pipeline. It has only been operational since May of 2014.

2. ***Admin costs in workpapers***: This comment came from a draft version of the study. The actual admin costs are shown in Table 4 of the report.
3. ***Capacity Costs in workpapers:*** Both PG&E and the CCA always face the same cost for market RA and new capacity. Furthermore, the concerns expressed are for a period that is included in the generic model but not included in the results.
4. ***Opt-outs too low*:** The opt out rates were highest in Marin's original communities, but in the case of Sonoma Clean Power and for new areas added to MCE, the opt-out rates have been around 10%. The opt-out rates so far for CleanPower SF are below 5%. Thus, we believe the opt-out assumptions are reasonable and in any case, a 20% opt-out rate would not make a difference in the study's conclusions.
5. ***GHG emissions rates.*** A section will be added to the Appendix explicitly laying out the greenhouse allowance pricing and how the total emissions were calculated.
6. ***Renewable Costs***: The derivation of the renewable costs is shown on pages 13-16 of the Report as well as Appendix B. There are many renewable energy contracts signed by municipal utilities and other CCAs, where the contract pricing is known. MRW endeavored to be realistic yet conservative in its renewable cost estimates. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low.

**IBEW (April 30)**

**General Comments**

***Need to see full documentation:*** Full documentation is provided in report, appendix and access to workpapers.

***Impossible to forecast more than 5 years in advance:*** While it is difficult to forecast with precision the further out one is looking, the important matter here is that the PG&E and CCA forecasts rely on consistent underlying forecasts. Our analysis is internally consistent between the CCA and PG&E, and we have explored the sensitivity of the results to variations in the key parameters.

**Specific Comments**

***"static load [forecast] for all sectors after 2019 is simply wrong" (emphasis original):*** The load forecast is from the California Energy Commission, and is developed by a dedicated staff there in consultation with PG&E.

***"The estimate of 15% premium for Alameda County based solar projects is too small."*** MRW endeavored to be realistic yet conservative in its renewable cost estimates. All assumptions here documented. Nonetheless, we understand that Steering Committee members have found these estimates to either too high or too low.

***The proposed power supply should have ZERO reliance on unbundled RECs.*** No unbundled RECS were assumed in the analysis.

***GHG issues in the three scenarios:*** There was an error in the preliminary results slide relied upon for this comment. It has been corrected.

***Greater Local build-out of renewables.*** As noted above, a high local renewables case will be included as an addendum to the report.

***High PCIA the status quo, not a sensitivity:*** While the PCIA will likely exist throughout the forecast period, there is uncertainty as to what the level will be. Thus, it's reasonable to look at potentially high PCIA levels and low PCIA levels to see how they affect CCA rates. In other words, it seems appropriate to include this variable in the sensitivity analysis. The PCIA was explicitly modelled so as to be consistent with the underlying power prices and retail rate forecasts. An arbitrarily high PCIA is presented as the sensitivity case.

***Economic and Jobs Analysis:*** The concerns raised here are addressed in the final report and appendix.

## Rivera, Sandra, CDA

| | |
|---|---|
| **From:** | Erik Pearson <Erik.Pearson@hayward-ca.gov> |
| **Sent:** | Tuesday, June 14, 2016 5:34 PM |
| **To:** | Rivera, Sandra, CDA |
| **Subject:** | FW: Extending the CCA Technical / Feasibility Study comment period |

Hi Sandra – I'm forwarding this to you in Bruce's absence. Thanks.

Erik

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**From:** Erik Pearson
**Sent:** Tuesday, June 14, 2016 5:32 PM
**To:** 'Jensen, Bruce, CDA'
**Cc:** Alex Ameri
**Subject:** RE: Extending the CCA Technical / Feasibility Study comment period

Hi Bruce,

Thank you for extending the comment period for the Technical Study to June 15. We would like to see the Technical Study revised to include anticipated rates for commercial customers. Chapter 3 provides potential bill savings for residential savings, but as we market EBCE to the community, we will need to have information about rates for all customers. Please add to Chapter 3 information about anticipated rates for large and small commercial customers. Thank you.

Erik Pearson, AICP
Environmental Services Manager
CITY OF HAYWARD
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510-583-4770
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**From:** Jensen, Bruce, CDA [mailto:bruce.jensen@acgov.org]
**Sent:** Thursday, June 09, 2016 11:00 AM
**To:** Jensen, Bruce, CDA
**Subject:** Extending the CCA Technical / Feasibility Study comment period

Hello, all – we have determined that we can provide a minor extension of the review / comment period on the Tech / Feas Study from June 10, tomorrow, to end of business on June 15 next week.

I will be away from the office that day and for some time, so I will provide contact and submittal information for this and other CCA issues either tomorrow or early next week.

Thanks, and as usual, if you have any questions, let me know.

Bruce Jensen
Alameda County Planning Department
224 West Winton Avenue, Room 111
Hayward, CA 94544
(510) 670-5400

THE CITY OF

PLEASANTON.

June 15, 2016

Bruce Jensen
Alameda County Planning Department
224 West Minton Avenue, Room 111
Hayward, CA 94544

Re: Draft Technical Study for Community Choice Aggregation Program in Alameda County

Dear Mr. Jensen,

On behalf of the City of Pleasanton, I would like to acknowledge the effort that you and the Community Development Agency staff have put toward the Community Choice Aggregation Project and the East Bay Community Energy Steering Committee. The City of Pleasanton reviewed the aforementioned Technical Study and would like the following items to be considered prior to the County Board of Supervisors consideration of the Study.

1. The Study accurately highlights the key risks facing the County CCA as a financially viable organization; low power prices offered by PG&E, future high renewable prices and costs and Power Charge Indifference Assessment (PCIA). These risks are what other CCA organizations have faced as well. However, we believe the study lacked sufficient sensitivity analysis and could have provided a more robust assessment of these key risks, and how they impact customer retention and the financial viability of the CCA.

2. The Study's scenarios focus on two local renewable resources – wind and solar – as supplies for the CCA. Costs for these two sources have declined dramatically over the last decade, and in addition Alameda County does not have the potential for repowering its portion of the Altamont Pass wind project. We believe the Study could have developed a more robust analysis of the risks and impacts of high renewable prices and costs.

3. The Power Charge Indifference Assessment (PCIA) is assessed by PG&E on an annual basis on all customers who do not opt out of the CCA program. The PCIA charges by PG&E represent a significant cost to CCA customers. Some CCAs are working together in an attempt to manage upcoming risks associated with future PCIA charges. The future Alameda CCA should collaborate with the other CCAs in the Bay Area in ensuring that PCIA charges do not damage the competitive position of the new organization.

4. The loads and forecasts assumed in the report are quite lower at 0.3% compared to other municipal utilities that often use a 2% growth rate in electrical load in their long-range supply planning. This was also noted in the comments submitted by IBEW.

**OPERATIONS SERVICES DEPARTMENT** **P.O. Box 520, Pleasanton, CA 94566-0802**

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**Administration**
**Streets**
**Utilities**

**Support Services**
**Parks**

5. Although the scope of work (SOW) did include an analysis of rates from a scenario analysis and the Study did include such an analysis. The Study SOW did not request analysis of rates and billing issues from a customer perspective. We believe that additional consideration of the impact of rates on customers is crucial in understanding the risks to the CCA of customers either opting to remain with PG&E or returning to PG&E due to dissatisfaction with the prices offered by the Alameda CCA.

6. Local renewable energy development can provide an important long-term source of renewable electricity for the Alameda CCA. The Study's Cost and Benefit Analysis illustrates the importance of renewable costs and demonstrates how high renewable costs can all but eliminate any price advantage of the CCA over PG&E. As such, these costs represent a significant risk for the Alameda CCA.
   - Purchasing renewable power resources from within the State, but outside of Alameda County, can be carried out at a relatively low cost.
   - Building local solar and wind generation in the Bay Area is considerably more expensive.

   We are concerned that this premium underestimates the costs of renewable power development.

7. The sensitivity analysis presented in the Study highlights the key risks faced by the Alameda CCA. These risks are: low power prices offered by PG&E, future high renewable prices and costs, and PCIA charges. We recommend that additional modeling work be carried out on these three key risks and their impacts on Alameda CCA's balance sheet and reserve requirements.

Recommendations for further Study:

1. Over the past 6 years many communities have developed and implemented CCAs. As such, their experiences, strategies, and approaches to providing their customers with a cost competitive and cleaner energy alternative can be instructive. Although a comparison of CCAs was not included in the Technical Study RFP and therefore was out of scope for the Study, we believe that such a comparison could be beneficial for the CCA advisory steering committee as well as the individual municipal participants.

2. One of the key risks of a new CCA is the initial development of its rates. The RFP and the Study do not reference any specific goals or strategies around rate design. The approach to rate design should be included as it drives much of the operational and procurement decisions of the CCA.

3. Further assessment of the value and risk of hydropower is recommended based on the information provided in Scenarios 2 and 3, with each relying on a significant portion of the Alameda CCA supply portfolio being comprised on hydro generation. The consideration of purchasing hydro has financial, economic, regulatory and political risks and ramifications, which need to be further explored.

4. The Study does not assess in detail issues around customer opt-in retention. Rather the Study assumes that 15% of all customers, across all classes, would opt to remain with PG&E. Under Scenario 1 of the Study, the overall 15% opt out of customers is questionable given the negative GHG impacts of this Scenario. Because of this high opt-out rate, the viability of the CCA could be significantly at risk. Further study of Scenarios 1-3 should be conducted to further explore the opt-in retention and the viability

In summary, we find shortcomings in the Study's rate forecasting and its assessment of hydropower risks (availability and cost) and the risk of high-cost renewables creating a competitive and rate disadvantage for the CCA. Further, we suspect that some of the load forecasting and GHG savings estimates may be overly optimistic. We recommend further study of rate design, utility exit fees (Power Charge Indifference Assessment, or PCIA), and the cost premium for local (in County) renewable energy projects and the ability of the CCA to finance those projects. We further recommend benchmarking the Alameda CCA against existing Bay Area CCAs to evaluate the strategies and approaches used to provide their customers with a cost competitive and cleaner energy alternative to PG&E power.

Sincerely,

Kathleen Yurchak
Director of Operations and Water Utilities

Cc: Mayor Jerry Thorne
Vice Mayor Kathy Narum
Councilmember Karla Brown
Councilmember Jerry Pentin
Councilmember Arne Olson
Nelson Fialho, City Manager

Berkeley Climate Action Coalition

June 14, 2016

Bruce Jensen
Alameda County Planning Department
224 West Winton Avenue, Room 111
Hayward, CA 94544

Dear Mr. Jensen,

The Berkeley Climate Action Coalition, whose membership includes over 650 East Bay residents, community organizations, and educational and religious institutions working to help the City of Berkeley reach its Climate Action goals and promote greenhouse gas reductions throughout the Bay Area, writes to submit comments regarding the June 2016 technical study conducted by MRW concerning the formation of East Bay Community Energy. We are very excited about the prospect of having a community choice program in Alameda as we believe it will significantly advance our climate action and sustainable economic development goals.

We would like the final draft of the technical study to include an expanded analysis of community solar and demand reduction as follows:

**1. Community solar**

The MRW study estimates that the development of small-scale local solar (<3MW) will cost 55% more than projects in "areas with the best solar resource" (which we understand to mean utility-scale solar projects located in the central valley and desert of southern California). A recent report by the highly respected Rocky Mountain Institute (RMI) states that "community-scale solar" (.5-5MW) can be cost-competitive with utility-scale solar. RMI identifies measures that can be taken to reduce costs of community solar by up to 40%.

Furthermore, RMI notes that community solar is inclusive of renters and low-income households (equity goals to which that EBCE subscribes) and has siting and transmission advantages over remote utility-scale solar projects. RMI concludes that community solar is the "sweet spot" between behind-the-meter and utility-scale solar.

MRW should model buildout scenarios that substitute various quantities of community-scale for utility-scale solar development. We'd like to see how the inclusion of community solar would impact economic development and rates.

**2. Demand side management**

MRW models 6 Gwh of annual incremental energy efficiency savings. This represents only 0.075% of load. (We are a bit confused by figures in Appendix G suggesting a much higher potential for energy efficiency and would like clarification as to what percentage of load reduction has actually been analyzed.)

SB350 calls for energy efficiency standards that are projected to reduce energy demand by 30% by 2030. Much of this demand reduction will be achieved in the electricity sector.

MRW should incorporate scenarios in which EBCE achieves demand reduction of 5% (matching Marin Clean Energy's demand reduction goal) and 18% by 2025, a national goal prescribed by RMI. Such reductions can be achieved using demand side management methods in addition to making energy efficiency improvements in buildings. Also, we propose that EBCE explore the possibility of a performance-based compensation arrangement in which the demand reduction contractor is compensated on the basis of "negawatt-hours" of energy savings.

It's important to understand now how big a role demand reduction will play in EBCE as this will affect the content of the RFP and, ultimately, the choice of program service provider(s).

Thank you for your consideration.

On behalf of the Berkeley Climate Action Coalition,

Rebecca J. Milliken

Rebecca Milliken
*Climate Action Coordinator*, Ecology Center
2530 San Pablo Ave, Berkeley, CA 94702
Email: rebecca@ecologycenter.org, Tel: 510-548-2220, x 240

**Response to the MRW "Technical Study for Community Choice Aggregation Program in Alameda County"**

**Presented By: Chuck Rosselle**

**E-mail: crosselle@yahoo.com**

**Telephone: 510-206-4412**

The Technical Study takes a conservative approach to the implementation of a CCA program for Alameda County by extrapolating current guidelines and practices well into the future. This approach ignores the fact that the power supply environment in both California and the nation is highly dynamic. Nevertheless, the Study provides a service in that it describes the requirements of the implementing legislation, benefits and risks inherent in the near term energy supply environment and a reasonable range of near term operational scenarios that responsible authorities can consider in establishing such a program.

The Study concludes there is a high probability that Alameda County can successfully implement a Community Energy program meeting statutory requirements which initially provides at least a minimal benefit to the ratepayers of Alameda County. This should not be surprising; Marin Clean Energy is currently providing a similar program delivering exactly this result. The Technical Study does provide assurance for decision makers that there are no current conditions in Alameda County that would preclude the implementation of an Alameda County CCA similar in function to Marin Clean Energy.

In my opinion, the Technical Study does not address biggest risk inherent in the successful operation of the CCA as an on-going business entity. In addition, it would also seem to underestimate the scope of effort required to successfully deliver value to its constituent customers. The purpose of this response is to identify the risk and describe actions necessary to mitigate the risk and successfully deliver the necessary scope of services necessary provide value. These actions are presented for consideration by those responsible for implementation of the Alameda CCA.

The single biggest risk for the Alameda County CCA program is that the overall trend towards County CCA's may be too successful. MWR has indicated that nearly all coastal counties in California (including most of the high population counties) have active plans to establish a CCA. As the number of CCA's grows, they will increasingly compete with the each other for the same sources of generation, some of which (in particular the most attractive low GHG sources) are currently controlled by the IOU's. This will likely place upward cost pressure upon these sources of power and potentially cause shortages, particularly in key power supply categories.

Additional CCA's will also put upward pressure upon the size of the PCIA. Not only will the IOU's fixed costs be spread across a smaller user base, but also the risk of stranded cost increases. This risk will continue until the CPUC and the IOU's permanently resolve any ongoing stranded asset and cost issues arising from the changing role of the IOU. High cost along with uncertainty threatens to impact the ability of the CCA's to succeed in the marketplace. If the Alameda County CCA cannot differentiate itself by offering better service or attractive pricing (hopefully both), ratepayers could fail to see the benefit of being served by the CCA as opposed to the incumbent utility, e.g. PG&E.

For the first sixty years of its existence, stable technology and fuel costs allowed the utility industry to cost effectively electrify nation utilizing the regulated monopoly model. In the 1970's the model created an overhang of stranded asses and failed projects as fuel cost volatility, turbine technological advances and regulatory compliance issues (particularly in the nuclear industry) caused utilities to make bad business decisions leading to failed capital projects. Ratepayers typically paid for these decisions as guaranteed cost recovery permitted the utilities to pass the costs of their decisions through to their customer base. Over the last twenty years the industry and its regulators have struggled to evolve a new model that rectifies the perverse incentives of the cost recovery model for an industry undergoing rapid technological change. There is no final consensus as the effort is on-going. Appendix A "The Evolution of the Power Grid" provides additional detail for anyone interested in the history of this era.

Technological advances in renewable generation, energy storage and network technology are now creating conditions which could easily lead to a new round of stranded asset risk not only for the natural gas generation infrastructure but also for the "peaking" plants being replaced by cheaper storage and the related transmission infrastructure which may become obsolete. Further complicating matters from a CCA perspective is the fact that the IOU's have traditionally favored support for their transmission infrastructure (which is subject to cost recovery) over support for an increasingly fragile distribution infrastructure, which is a cost of maintenance. Many specifics of these issues, as they relate to the Bay Area are documented by Bill Powers in "Bay Area Smart Energy 2020".

Assuming current plans come to fruition, within the next few years CCA's could easily become the majority electric power vendors for residential and commercial consumers in California. The joint CCA IOU energy supply model has the potential to succeed as the true successor to the traditional regulated monopoly model. The Alameda County CCA representing one of the largest and most diverse counties in the state, contains an enviable cross section of some of California's leading EV, battery, and solar energy technology expertise. It has the opportunity to be a leader in this transition to locally supplied power. If the CCA's do not aggressively assume this role, they risk being embroiled in the spillover from the cost pressures associated with a potentially expanding stranded asset regime along with the operational issues associated with the existing distribution network.

For many years, the utility industry presented an aspirational model of American life. Reddy Kilowatt represented the convenience and labor saving potential of wonderful devices and appliances that improved the quality of our existence. This was a direct link to Samuel Insull, the pioneering founder of Commonwealth Edison in Chicago; an early champion of the development of electric appliances as a way to increase the utilization of his turbine generators that were idle during the day when the lights were off. The entire electric appliance industry was an entrepreneurial response to this rather simple decision.

The industry's more recent struggles to restructure itself have had an unfortunate by-product of commoditizing electric power and often making its increased cost seem more like rent seeking then an opportunity for creativity. Nevertheless, some of the most innovative re-structuring is occurring at the municipal utility level; the cities of Boulder, CO and Austin, TX come to mind. The CCA initiative could achieve a similar outcome.

For a number of years, both the environmental and entrepreneurial community have recognized the potential of enhanced electrification. Not only is there great flexibility regarding how it is generated (including many which are environmentally benign), but also the economic potential is enormous. The electric power industry is the largest in the world. The biggest hurdles to enhanced electrification have been the lack of low cost, easily accessible sources of generation and the inability to store electric power in a low cost, high density, easily transportable fashion that competes with refined hydrocarbon fuels. As personally accessible electric power generation evolves and storage becomes readily accessible, the barriers to access are being lowered. Creative electrification has become an aspirational vocation for many individual entrepreneurs. What has been missing is a proper delivery mechanism.

The key is to delivery is a roadmap for the future, the framework to allow it to happen and the flexibility to respond to unexpected outcomes. The result can be a future electric power environment which is closer to the user, encouraging to innovation, and supporting the tenets of the "sharing economy":

- Enhancing experience and lifestyle
- Supporting mixed use of assets
- Supporting small scale entrepreneurialism
- Eliminating commoditization
- Taking maximum advantage of the local environment

What would such a roadmap and framework look like?

### A. It would emphasize local generation.

- Local distributed generation resources reduce dependence upon competitively sourced external generation and enhance the ability to provide greater benefits to the user base and local entrepreneurs.
- Alameda County has considerable resources potentially supportive of local distributed generation (about 300,000 rooftops - many west facing, a significant commercial community, wind resources, synthetic gas generation potential, etc.). The Alameda CCA should conduct a realistic review and establish its ability to achieve eventual local energy independence, either in its entirety or for significant portions of the county. This Alameda CCA should also establish aggressive local development targets to be achieved through a combination of residential, commercial and utility grade renewables coupled with local CHP. These should be expected to be at least in the range of 50%.
- While historically uncompetitive, the cost of home PV generation is rapidly approaching competitive rates. See Appendix B for a recent LCOE discussion. The Alameda CCA should support and accelerate the adoption of this evolving capability.

- Similarly, distributed energy storage costs are rapidly approaching commercial viability. The maturation of this technology is being driven by the evolution of the EV. The Alameda CCA should support and accelerate the adoption of this technology as well.
- Net Metering has a limited lifetime. In the near future, a more realistic tariff structure will evolve in California. The Alameda CCA will be able to procure locally developed power at a competitive marginal price.

**B. It would create a "one stop shop" for the local implementation of desirable generation and supporting technologies. This would include:**

- A catalog of local community scale solar locations (open space, covered parking, commercial rooftops, etc.) and program to solicit local development by offering financing and permitting assistance
- A catalog of other attractive local sources of generation (wind, CHP, etc.) and a program to solicit development by offering assistance as described above
- Pre-established financing options for locally qualified suppliers. The Alameda CCA should make attractive financing for qualified suppliers a condition of any banking relationship and/or establish bond financing for local development once permitted by the maturity of the program.
- A streamlined process that supports fast-tracked permitting for projects that conform to pre-established standards (see below).

**C. It would establish standards for the technologies necessary to develop the resources required to develop local energy generation and storage**

- Germany has installation costs for local solar PV that are roughly half of US costs. "Soft costs" are the primary driver of this cost differential and complex permitting structures are the biggest driver of these soft cost differentials. The Alameda CCA should develop standardized configurations that support fast track permitting in order to reduce costs. Similar standards should be developed for the full spectrum of desirable generation and storage projects.
- Standardization should also include instrumentation that supports interoperability with distributed power control systems and supports demand response management.
- By providing a market and standardizing the configuration of local distributed generation technologies, the county could create configurations that enhance project asset values. This should overall enhance lender acceptance and could permit FNMA and FMCC to reduce their opposition to PACE programs, enhancing the viability of this financing option.

**D. It should establish standards for a next generation Distribution Network**

- The distribution network is the least robust component of the generation, transmission and distribution hierarchy. It is difficult to cost justify distribution improvements in a power generation hierarchy which classifies remote generation and transmission as high value revenue producing assets and distribution assets as a maintenance expense. In a distributed energy environment, where a greater proportion of the generating assets exist at the periphery, a robust distribution network assumes a greater level of importance.

- Further, the preponderance of events which cause unreliability in the electric supply network occur within the distribution network. Hurricane Katrina was an extreme example of this phenomenon. Several Northeastern and Mid-Atlantic States noted that micro-grids performed extremely well in comparison to the legacy network. They are aggressively pursuing the broader development of micro-grids to enhance distribution network performance. They are finding that not only do micro-grids improve customer satisfaction (due both to enhanced reliability and undergrounding), but they also improve overall network reliability and demand management capability.
- The Alameda CCA should develop a program to enhance the existing distribution network by deploying micro-grid technology.

## E. It should expand the scope of the IT Services needed for success

- In addition to the basic business services described in the MRW Technical Study, the Alameda CCA should also develop the basic system support structure necessary to provide distributed generation monitoring and management. The CCA should also provide Demand Monitoring and Management capability. These services should be built to interoperate with customer devices such as PC's, smart phone and tablets.
- The services provided by these systems are critical for customer support and will provide the CCA with a valuable ability to demonstrate its value to the customer base.

## F. It should aggressively promote its programs and services to the local community and take a leadership position in coordinating and lobbying for common actions within and among its peers

- Some of the initiatives and programs defined in this document may not be part of the scope of effort being currently considered by the CCA or may even be within the scope of responsibility of the IOU (PG&E).
- Nevertheless, if the CCA is to provide a successful, value added service to the citizens of the county (its customer base, I would strongly encourage that the CCA either on its own initiative or in conjunction with its peers negotiate to provide a complete set of services of the type defined herein.

# Appendix A

# The Evolution of the Power Grid

**The Development of the Modern Power Industry**

Thomas Edison opened the first commercial power plant in the United States on Pearl Street in Manhattan in September of 1882. The Pearl Street plant used a coal fired boiler to drive a reciprocating steam engine that in turn provided direct current (DC) power to one square mile of Lower Manhattan. The DC power generated by Edison could only be distributed up to a mile from the generation site. The Pearl Street plant was the first to standardize power generation for multiple users, as up to that time industrial users choosing to use electricity generated their own. In the same month, the country's first renewable power was generated in a hydroelectric power plant operating on the Fox River in Appleton, Wisconsin. The plant, later named the Appleton Edison Light Company, was constructed by Appleton paper manufacturer H.J. Rogers, who had been inspired by Thomas Edison.

The modern utility system evolved in Chicago in 1892. When Samuel Insull, the British-born secretary of Thomas Edison arrived in Chicago in 1892 the town hosted more than twenty companies commercially producing electricity. Insull assumed the presidency of the small Chicago Edison company, one of many Edison franchises around the country. While Insull did not pioneer all of the early utility innovations, he was the first to combine all of the managerial and technological innovations that transformed the utility system into its modern company form.

Insull realized that his company could make more money by increasing what became known as the "load factor", the ratio of average daily or annual power load to the maximum load sustained during the same period. Insull installed equipment to meet the peak load of use during a day, typically in the evening when customers used electric lights. He understood that if he could find customers who would use electricity during off-peak times, he could increase income without additional capital expenditure. Those customers existed, but many generated power for themselves. He enticed customers such as street railway companies, ice houses, and other businesses by offering off-peak power for a lower cost than they incurred themselves.

Insull also exploited new technologies. During the late 1880s and 1890s, electricity was generated using reciprocating steam engines. Large, bulky, noisy, and hard to maintain, the reciprocating engines of the day converted up-and-down motion to rotary motion for use by electric generators through the use of a large flywheel. Steam turbines on the other hand, produced rotary motion directly, as steam passed through vanes on a long shaft. Much smaller in size, simpler mechanically, and quieter than reciprocating engines, steam turbines produced a greater amount of power from a smaller package. More importantly, the turbines could be scaled up to produce even more power with proportionally less investment in material, allowing a utility to produce electricity at an even lower unit cost. Insull ordered his first turbine-generator set from the General Electric Company in 1903, a 5 MW unit. Pleased with the unit's performance, he ordered a second 12 MW unit in 1911.

Unlike his former patron Edison, Insull was an early adaptor of Alternating Current (AC) generators and transformers. Developed in the 1880s, AC transformers overcame the technical limitation of transmitting low-voltage direct-current to distances beyond one mile. When power produced with already existing AC generators was transformed up to high voltages, current could flow for many miles without significant degradation. In 1896, Edison competitor Westinghouse Electric built a system of hydroelectric power plants at Niagara Falls that produced power for transmission to Buffalo, 20 miles away. The AC power illuminated lights, just like direct current, but more importantly, it powered the new AC motors that had recently come to market. AC motors, in turn became increasingly popular for their use in small electric appliances. These appliances not only increased overall power usage, they also helped spread power usage throughout the day, thus increasing utility load factors.

Finally, Insull also realized that competition in the electric power supply business would never allow him to effectively invest in the scalable turbine-generators and AC transmission systems he needed. To remedy the problem, Insull sought a monopoly position for his company. He took a two-step approach. The first step was to eliminate competition by acquiring the 20 other companies he competed with in Chicago. By 1907 he was the only remaining utility and he renamed the firm "Commonwealth Edison. The second step was to protect his monopoly position by aggressively supporting beneficial regulation.

**The Regulated Power Monopoly**

Modern regulation evolved during the Progressive era. At the heart of progressivism was a governmental acceptance of the notion that some industries constituted "natural monopolies." According to academic economists, industries like utilities required economies of scale in order to support the capital investment necessary for creating infrastructure and services. Municipal ownership and state regulation were the common methods for creating "natural monopolies". Progressives preferred state regulation. Wisconsin and New York pioneered regulation by establishing jurisdiction over the rates, schedules, service, and operations of their state's railroad companies. In July 1907, the Wisconsin legislature extended similar regulation to that state's electric utilities.

The Wisconsin Regulatory Commission compelled utilities to develop standard accounting techniques. It had the right to investigate the companies' books as part of the process for determining rates based on the physical valuation of a company's properties. Regulation, as viewed by its initiators, was intended to enforce the electric power companies' "obligation to serve" their customers. They were required to build infrastructure and serve all customers with as few interruptions as possible without discrimination. To fulfill their obligation, they needed to be able to raise capital and build plants to meet their projected loads. Utilities rates for service were based upon their operating costs plus their investments in equipment (the "base rate") plus a fair rate of return. In return, a utility company earned valuable rights. The most important right was the right to operate as a natural monopoly within its service territory. It also earned the right of eminent domain, formerly a power reserved by the state, so it could obtain property for its generating plants, transmission towers, and other equipment.

By 1914, state regulation had become standard and 44 states had established oversight of electric utilities using the Wisconsin model. Unlike railroad executives who resisted regulation, utility executives like Insull embraced the benefits. Regulation strongly supported electrification and infrastructure development. Investors knew that regulators not only oversaw the financial accounts of utilities (in an era before public disclosure of accounts was required) but also guaranteed a profit. Investments in utility companies were not as speculative as those in unregulated companies. Utilities were awarded high investment grade bond ratings. They could favorably raise money at attractive interest rates which reduced the costs of their capital projects. Regulators not only ensured that these project costs went into the utility rate base but also that generation and transmission assets were fully utilized. Eventually, regulators even allowed them to pass on-going project costs through to customers before the projects were actually completed, a practice known as Construction Work in Progress (CWIP).

**Federal Government Involvement in the Power Industry**

By 1940, all states had formed regulatory commissions with authority over their in-state utilities. Nevertheless, it was still not economical for private utilities to fully develop all available generation resources and provide complete electrification throughout the country. Under its interstate commerce mandate, the federal government became involved in the power industry for the first time in order to support the development of large hydropower generation facilities which were beyond the financial capability of even the largest utilities. The government developed and subsequently sold wholesale hydropower to utilities regardless of jurisdiction. In 1930 the Federal Power Commission (FPC), was established to coordinate such interstate federal hydropower development.

In 1933, the Tennessee Valley Authority was created as a federally owned corporation to provide electricity generation and economic development to the hard hit multi-state Appalachian region. In 1935, the federal government established the Rural Electrification Administration (REA) to provide electric power to the remote areas of the country previously not considered to be economically feasible to electrify. REA cooperatives pioneered the development and implementation of high voltage rural distribution networks. Today, most rural electrification is the product of locally owned rural electric cooperatives that got their start by securing government backed loans from the REA to build lines and provide service on a not-for-profit basis. REA funding is currently administered by the Department of Agriculture. That same year, under the Federal Power Act, the FPC was transformed into an independent regulatory agency and its authority was expanded to regulate both hydropower and interstate electricity transmission.

**Growth and Transition**

For over sixty years, state regulated electric power monopolies were successful in achieving the goal of national electrification. Unlike their regulated brethren in the transportation industry, power companies did not need to worry about competition from other forms of service. Indeed, few considered market alternatives. Power demand grew faster than GDP and technological advances, particularly more efficient large turbines and high voltage transformers, lowered the production costs for large generation plants while increasing the distance over which power could be economically transmitted. The industry became more capital intensive. Utility load planners, mindful of their dual mandate of low costs and reliable power planned and constructed large, efficient "base load" generating plants along with "peaking" plants for short duration use. In the Pacific Northwest, hydropower supplied both base load and peaking generation. The industry established an enviable record of successfully building and operating these ever larger generation plants. Most importantly, the prices for the industry's main fuels, coal and oil remained low and stable, allowing planners to comfortably build for the future.

The extended period of financial and business stability caused the industry to become highly dependent upon large "base load" generating plants for their business model. Unless generating capacity outstripped demand, regulated power utilities could operate their largest units at maximum capacity whenever they were available and be guaranteed a negotiated rate of return. In fact, the moment a shovel broke ground on most projects, they were already part of the rate base. This favorable environment ensured both a positive cash flow and a healthy return on invested capital. When coupled with the industries traditionally high credit rating, it also allowed utilities to confidently invest for the future. Unfortunately, it also made them extremely vulnerable to any disruption in the underlying factors that supported the business model, namely industry financial quality, stable fuel prices, technological change and the regulatory climate. Over the last forty years the industry has seen disruption in each of these four areas. It has responded with varying degrees of success. The story began, innocently enough as a response to the impending clean air legislation embodied in the Clean Air Act of 1970.

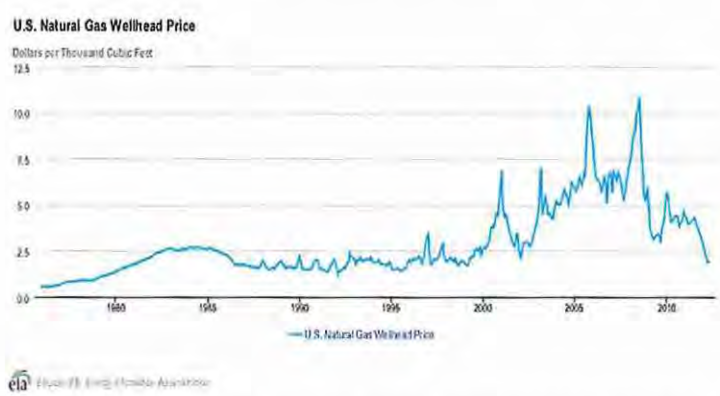
**Disruption Leading to Deregulation and Restructuring**

Anticipating the Clean Air Act and potential coal plant emission restrictions, low and stable crude oil prices in the late 1960's caused the industry to briefly shift its new construction base load emphasis from coal to cleaner burning petroleum-fired generation. The OPEC inspired oil price shock of 1973 created rising and unstable oil prices, questioning the wisdom of this shift. With environmental concerns threatening regulatory uncertainty in coal and global dependencies creating pricing instability in oil, the power industry was faced with potential disruption in their traditionally stable fuel supplies. There was wide industry interest in finding a stable and cost effective long term fuel source for large thermal power generation. Such a source appeared available in the form of nuclear power. With no apparent atmospheric pollutants and fuel costs that were a small percentage of the cost of generated power; nuclear provided an apparent economic and environmental advantage over coal and oil.

In the 1970's, power utilities made a major commitment to large base load nuclear power generation projects. Indeed, had all of the planned capacity been successfully deployed nuclear power today would be the largest single base load power source in the United States. Instead by the mid-1980s well over half of the planned nuclear plant projects were no longer viable due to a slowing rate of growth in electricity demand, significant cost and time overruns on projects, and increasingly complex regulatory requirements. Of the 249 nuclear power reactors originally ordered during this period, 120 were canceled and 26 were prematurely shut down. Even when successfully constructed, the technology proved to be operationally more complex than the industry was expecting. It took until the early 2000's for the overall capacity factor of the eventual nuclear fleet to reach acceptable levels. In making the transition to nuclear power, the industry faced significant financial and technological disruption.

It is difficult to overstate the impact this disruption had upon utilities, state regulators and the financial community. Regulators disallowed construction costs for failing base load power projects. Utilities could no longer automatically count on being reimbursed for their projects. In 1985, this action coupled with severe project cost overruns caused the financial industry to lower their recommendations for utility equity and reduce the credit ratings for the most heavily impacted utilities. The industry did not fully recover until the early 1990's. Many academic economists attributed this period of industry disruption to a concept termed "rate-of-return bias". They posited that not only does regulation cause utility companies to over-use capital during construction of their generating plants, but also when fuel costs become uncertain they tend to utilize that capital inefficiently. There was growing interest in the possibility of restructuring the power industry. The goal was the elimination of inefficient or unusable captive generating capacity, known as "stranded cost", and its replacement with competitively provided generation.

Power industry restructuring could not occur without deregulation. Deregulatory activity had already begun with Congress' attempt to forge an integrated energy policy in 1977 through the passage of the DOE Organization Act. This act consolidated various energy-related agencies into a Department of Energy (DOE). The following year, Congress passed the Public Utility Regulatory Policies Act (PURPA) of 1978 which opened the wholesale power markets to non-utilities. Prior to PURPA, utilities could utilize their monopoly status and refuse to interconnect or purchase power from non-utility generators at will. PURPA encouraged industrial power generation from waste heat ("cogeneration") by requiring utilities to purchase it at the "avoided cost" of building and operating their own plants. Congress also insisted that a separate independent regulatory body be retained, and accordingly the FPC was renamed the Federal Energy Regulatory Commission (FERC), preserving its independent status. FERC was asked to administer the new program described above.




Originally intended as a limited initiative to promote cogeneration and renewable power development, PURPA initiated a much broader set of changes. The industry consensus in the mid-seventies was that price controlled natural gas fueled generation would remain expensive, particularly relative to the average cost of the utility owned generation fleet. This was thought to make self-supply with natural gas burning generators uneconomic for most industrial users. Instead of remaining expensive however, the Natural Gas Policy Act of 1978 lifted the price controls on natural gas which had artificially reduced its supply and inflated its price since 1954. As decontrol of natural gas ended its artificial shortage, there was a dramatic reduction in natural gas prices. This trend lasted from 1980 through 2000 (see chart, above).

Technologically, newly developed combined cycle gas turbines rivaled and even exceeded the efficiency of the large steam turbines in use by the power industry. This overturned the prevailing wisdom that greater power generation efficiency could only be achieved through ever larger power plants. The power industry was now faced with additional regulatory and technological disruption. At the prevalent low gas prices, generators under 100 MW were as cheap to operate as coal or nuclear fired plants ten times their size. They had many operational advantages. They could be built quickly and cheaply, located where necessary and quickly amortized. They were flexibly capable of intermittent operation with minimal costs of regulation and environmental compliance. Distributed power provided by small gas turbines was a viable alternative to base load power. The Energy Policy Act of 1992 (EP Act) removed the final obstacle to supplier competition in the power market by allowing FERC to order transmission owners to carry power for other wholesale parties.

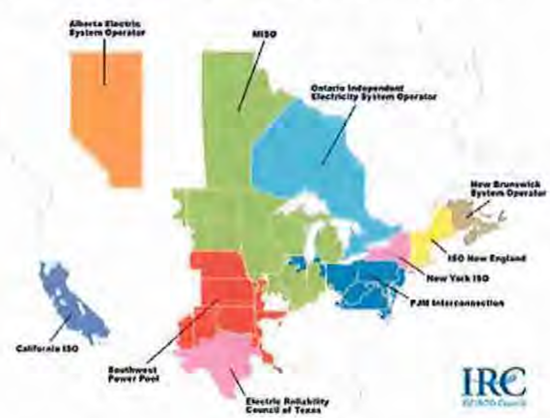
Throughout the latter portion of the 1980's and early 1990's both regulators and utilities in the largest power markets struggled to find stability amidst competition from natural gas and the increasing cost of power from large retail power plants caused by the fallout from the nuclear construction period, the rising cost of oil and the emission requirements being placed upon coal fired generators. Utilities were passing through the high costs of inefficient, un-built or delayed generation projects when at the same time they could often buy power more cheaply than they could produce it through the unregulated power exchanges arising under PURPA. If they could restructure, regulators felt they could direct their utilities to divest themselves of inefficient assets and cancel uncertain projects. Following the EP Act in 1992, many state regulators believed that the elimination of this barrier to entry, coupled with functioning, unregulated power exchanges created the conditions necessary for a smooth transition to a competitively restructured market. It was a position championed by ENRON.

In 1994, there was a second round of financial disruption in the power industry caused by the uncertainty created by PURPA and the EP Act. Utilities were now also open to a new business model. ENRON's delivered a message of unregulated power exchanges controlled by larger utilities wielding market power throughout the country. It was seductive. Larger utilities created unregulated "merchant" utility business units to competitively generate power. Between 1995 and 2001 state regulators directed their Investor Owned Utilities (IOUs) to divest themselves of 305 generating plants, comprising 156,000 MW or nearly 20% of all generating capacity in the country. About 75% of these divestitures went to the merchant utility subsidiaries of other IOUs. The non-utility generators (NUGs) supplying gas fired generation under PURPA and the merchant power subsidiaries of Investor Owned Utilities became known collectively as Independent Power Producers (IPPs). The combination of IPPs and power exchanges grew rapidly. From 1995 through 2005, utility purchases of unregulated power from IPPs grew more than twice as fast as the utilities own retail sales. In 1995, IPPs traded less than 8 million MW-h of electricity. By 1999 they were trading more than 1.5 billion MW-h of electricity.

Power exchanges became the mechanism for delivering unregulated power. As more of the nation's power became supplied through these exchanges rather than through dedicated generation, the potential for retail price abuse increased. Retail users only had access to power through transmission and distribution owned by a single utility. High cost utilities could use their ownership position to abusively pass those costs through to the end user. Industrial and commercial users had self-generation options and high costs therefore fell disproportionately upon the retail user. It was becoming apparent that there was a need to standardize the unregulated wholesale power delivery structure. Consensus emerged regarding two areas of standardized structure: elimination of inefficient "stranded costs" and open access to transmission and distribution.

The issue came to a head in 2000 as a result of events in California. In 1998 California became the first state to attempt to provide retail choice through the elimination of inefficient stranded costs and the provision of open and transparent transmission access. In 2000 this initiative created a crisis when IPP's and natural gas fuel suppliers withheld or manipulated power and fuel in order to create artificial power shortages and increase short term power costs. ENRON (the power exchange operator) had orchestrated the abuse of poorly conceived power exchange rules in order to dramatically inflate costs, leading to the bankruptcy of the state's largest utility, Pacific Gas and Electric. In 2001, when ENRON failed as a business its manipulation along with the complicit actions of its power and fuel supply partners exposed the full scope of the potential for the abuse of power trading through unregulated power exchanges. Exchange operators around the country began to standardize and tightly control their operations, reducing the profitability of many of the merchant power providers. In 2002, the ENRON business failure subsequently led to bankruptcies and re-structuring in the merchant power sector, challenging the merchant power providers and exposing their utility counterparties. It created a third round of power industry financial disruption.

FERC had recognized that utility restructuring impacted interstate electricity transmission. Between 1996 and 1999 they issued standards for utilities to dispose of uneconomic assets by recovering their stranded costs. They also established a mechanism for transparent power pricing and control of transmission assets. They defined the voluntary role of an Independent System Operator (ISO) or Regional Transmission Organization (RTO) to provide non-discriminatory access to transmission and consistent operation and management over power exchanges. In order to level the playing field, the Energy Policy Act of 2005 also expanded FERC's authority to impose mandatory power availability and reliability standards on the bulk transmission system and impose penalties on entities that manipulate pricing in the electricity and natural gas markets. The California experience enhanced the role of the ISO's and RTO's as power exchange operators. Today, states that trade deregulated power through power exchanges operated by ISOs and RTOs serve 68% of the electricity consumers in the United States by volume (see chart, right); the remainder still receive some form of traditional cost-of-service regulated power.



In 1999 Texas passed the Texas Electric Restructuring Act, becoming the first state to successfully introduce a complete restructuring of its electric power market to promote competitive power delivery. Restructuring included open transmission, choice for the state's retail consumers and a requirement to fully eliminate the vertical integration common in regulated utilities. Texas' utilities were directed to unbundle their power generation, transmission and distribution, and retail electric services in the form of three separate (but possibly affiliated) companies. They were also directed to divest generation capacity to the point at which 40% or more of the residential and commercial customers in their former service areas were competitively served. Control over the state's transmission network was consolidated under the state's Regional Transmission Operator, ERCOT and retail electric customers were subsequently given choice in the selection of their power provider. Currently fifteen states and the District of Columbia have restructured electric power markets along the lines of the Texas model. This includes all large northeastern states, as well as Illinois, Ohio, Michigan, Oregon and Texas (see chart, left). These states comprise 50% of US retail power sales by volume. An additional seven states partially implemented restructuring but have subsequently suspended completion as a result of the California experience.


Both electric power deregulation and power industry restructuring were facilitated by the availability of low cost distributed power generated from inexpensive natural gas. Beginning in late 2000 natural gas prices began to rise and experience volatile price swings (see chart on page 5). From a stable price below \$2.50 per 000-ft$^3$, natural gas prices peaked at well over \$10 per 000-ft$^3$ prior to 2008. Since exchange pricing allows all qualified suppliers to sell power at the price established by the last selected bidder, high natural gas prices worked to the advantage of merchant power suppliers who owned coal or nuclear generation capability. By 2001, the nuclear fleet had begun to operate with a high level of utilization. Merchant power suppliers such as Exelon and Entergy that had focused primarily on the purchase of nuclear generation units at a significant discount were benefiting financially from higher power prices.

A combination of pent up utility demand, government financial incentives, the desire of international vendors to enter the US market and recently streamlined regulatory processes caused there to be a "nuclear renaissance". By 2009, the Nuclear Regulatory Commission had received applications for construction and operating licenses to build 25 new nuclear power reactors. Unfortunately, the case for widespread nuclear plant construction eroded fairly quickly. Natural gas prices fell as abundant supplies returned along with the concurrent issues of slow electricity demand and financing unavailability. Licenses were issued for four plants (not coincidentally in cost-of-service regulated states) while schedules for the remaining license applications were significantly extended, suspended or cancelled.

The cause of the newly abundant natural gas supply was the successful expansion of hydraulic fracturing ("fracking") to release natural gas trapped in shale rock formations. By 2011, natural gas prices had fallen below pre-2000 levels at nearly \$2.00 per 000-$ft^3$. Consequently, merchant nuclear and coal fired power began experiencing pricing pressures. Nearly half of all nuclear power falls into the merchant category along with a quarter of all coal fired power. There has been some rebound as by early 2013 natural gas prices reached \$4.00 per 000-$ft^3$. Many natural gas drillers have indicated that they do not intend to expand drilling of existing shale reserves until natural gas pricing becomes more favorable. The EIA projects that this "favorable" price will be in the range of \$4.00 to \$6.50 per 000-$ft^3$ over the next 20 years. Time will tell, but this is still a low price range for natural gas and should the EIA projection come to pass, the resultant situation creates an equilibrium scenario for the US economy that assures:

- Natural gas remains competitive with nuclear and most coal for electric power generation
- Renewable electric power generation becomes cost competitive with fewer subsidies
- LNG exports remain viable, including costs for liquefaction and transportation, and
- Industrial processes that require natural gas as a feed stock remain domestically viable

Nuclear advocates were not alone in assuming that rising natural gas prices would make traditional generation sources more attractive. From 2000 through 2008, there was a renewed financial interest in all forms merchant power, including the largest Leveraged Buyout in history in 2007. As a result, the return of low natural gas prices has also initiated an additional round of merchant power financial difficulties, bankruptcies and restructuring:

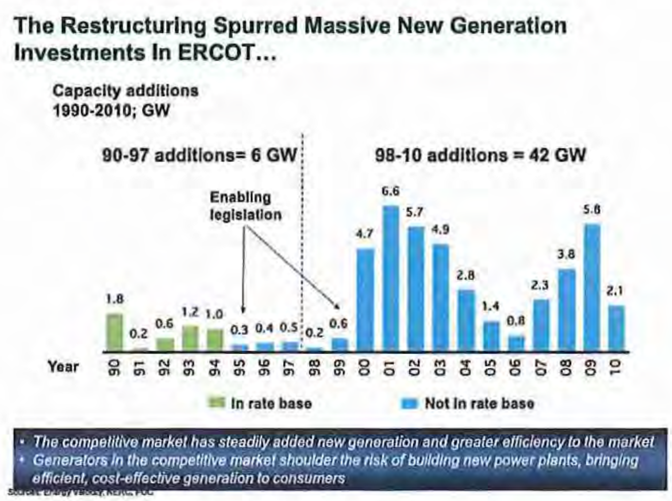
- **Exelon Corporation** stock fell over 7 percent when the PJM Interconnection announced that competitive bidding from external sources plus new natural gas power providers had produced a clearing price for future pricing of just \$59.37 per megawatt-day, about half of what analysts were forecasting and less than half of the \$136 per megawatt-day set in the 2015-16 future auctions. For Exelon, capacity revenue will fall about 41 percent in the year beginning June 1, 2016. After failing in an attempt to exempt its nuclear operations from Exchange bidding procedures, Exelon recently announced its intent to shut down its Clinton and Quad-Cities nuclear plants.
- **Energy Future Holdings** is undergoing restructuring under bankruptcy. The plan will restructure \$32B in debt in its Texas Competitive Holdings Business Unit with investors and creditors absorbing losses. Energy Future Holdings (the former Texas Utilities, Inc.) was the largest power supplier in Texas, created in 2007 as part of the largest leveraged buyout in history (\$47B). Note that this bankruptcy helps validate Texas' utility re-structuring model. Investors and creditors, rather than ratepayers are absorbing the results of poor business decisions.
- **Edison Mission Energy** (the merchant subsidiary of Southern California Edison) filed for bankruptcy protection in December of 2012 citing the costs necessary to bring its coal units into compliance with EPA Emissions requirements.
- **Dynegy,** an IPP has agreed to assume the Illinois coal and gas generation assets along with the debt of Ameren's merchant power subsidiary, **Ameren Genco**. Ameren, a Missouri utility has announced a re-structuring of **Ameren Genco** and will exit the merchant power business.

- **Dominion Resources** of Virginia is selling three fossil fueled merchant power plants in order to reduce the debt in its merchant power unit. Dominion is reducing debt to help cover the costs associated with the shutdown of its single unit Kewaunee Nuclear Plant in Wisconsin.

### The Future of Deregulation and Restructuring

ENRON understood both the benefits of unregulated power exchanges along with their potential for abuse. When low cost power is available, an exchange offers the potential to acquire it at competitive prices with no risk of stranded costs. But an exchange can't overcome the realities of the existing generation and fuel supply infrastructure coupled with the complexity of a grid not optimized for exchange use. Even when the worst examples of abuse were eliminated, a lack of competitive generation alternatives has made it difficult to gain pricing advantage. Indeed, many complain that the bid system used to set power procurement policies actually causes exchange pricing to exceed regulated cost-of-service pricing. This is the primary criticism leveled by the American Public Power Association (the primary utility industry trade group).

The larger exchanges, such as the California ISO, The Electric Reliability Council of Texas and the PJM Interconnection (Mid-Atlantic) have been aggressive in implementing a series of initiatives designed to enhance exchange benefit and reduce overall power costs. California and Texas were early adopters of detailed grid modeling that allowed them to better monitor and predict their power needs and reduce or eliminate power shortages and grid congestion. PJM pioneered the development of Capacity Payments, a mechanism for contracting with power providers on a future basis to reserve power at an established price in order to eliminate short term pricing abuses. Detailed grid modeling and Capacity Payments (power price hedging in California) are now standard features of exchange operations and the results seem to reflect improved performance. The latest PJM Capacity auction incented a number of new bidders to offer power resulting in over a fifty percent reduction in the offered price.



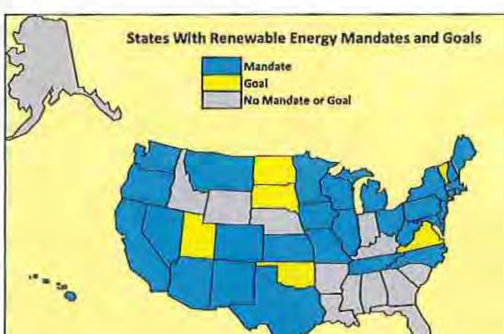

Texas is the most aggressive proponent of a disciplined restructuring in order to create a competitive electric power market. In the opinion of the Texas legislature and service commission, a functioning power exchange, disaggregated generation, distribution and marketing and unrestricted consumer choice are all required in order to create the conditions necessary for competition. For nearly ten years, Texas struggled to enhance and adjust this model in order to bring down its retail prices. Eventually, their success in attracting new, competitively supplied generation paid off.

***Texas Compared to the Rest of the Southeast***

The chart on the left contrasts the recent performance of Texas and its restructured electric market with the seven other southeastern states, all of which are regulated cost-of-service states. As can be seen in the Independent Power Producer Column (IPP) on the left, nearly 70% of all power generated in Texas comes from providers classified as IPP's. Most of this power has been competitively sourced, as Texas has constructed over 42,000 MW of in-state generation since 2000 (see graphic, left). By way of contrast, over 87% of the power generated in the other seven southeastern states comes from conventional utility sources, all of which are currently part of the rate base of their utilities. In spite of the significantly lower stranded cost risk in Texas, the cost of retail power across the region is comparable and moderate with Texas at 10.89 cents/kw-h while the weighted average of the other seven is 10.55 cents/kw-h.

| Selected Power Usage Data for January 2013: Texas vs. US Southeast Region (AR, LA, MS, AL, GA, SC, FL) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| (All Data in cents/kw-hr or Thousands of MW-Hours) | | | | | | | | | | |
| | Res. Rates (cents/kw-h) | Power Providers(1/13 - MWh - 000) | | | | | Power Sources(1/13 - MWh - 000) | | | |
| | | Tot | Util | IPP | | | Nucl | Coal | Nat Gas | Renew |
| TX | 10.89 | 33734 | 7047 | 23080 | 68.4% | | 2951 | 11733 | 15853 | 2734 |
| Pctg of Total | | | | | | | 8.7% | 34.8% | 47.0% | 8.1% |
| | | | | | | | | | | |
| AR | 8.74 | 5689 | 4109 | 1396 | 24.5% | | 1389 | 2718 | 1285 | 149 |
| LA | 8.76 | 8089 | 3730 | 1831 | 22.6% | | 959 | 1860 | 4344 | 228 |
| MS | 9.99 | 4041 | 2992 | 816 | 20.2% | | 311 | 463 | 3153 | 113 |
| AL | 10.84 | 12748 | 9515 | 2444 | 19.2% | | 3825 | 3573 | 3722 | 269 |
| GA | 10.25 | 10205 | 8836 | 942 | 9.2% | | 3045 | 3251 | 3412 | 284 |
| SC | 11.63 | 8316 | 8135 | 0 | 0.0% | | 5011 | 2095 | 919 | 154 |
| FL | 11.34 | 16220 | 14940 | 799 | 4.9% | | 2101 | 3262 | 10136 | 398 |
| | | | | | | | | | | |
| Wtd. Avg | 10.55 | | | | | | | | | |
| Total | | 65308 | 52257 | 8228 | 12.6% | | 16641 | 17222 | 26971 | 1595 |
| Pctg of Total | | | | | | | 25.5% | 26.4% | 41.3% | 2.4% |
| Source: US Energy Information Administration (eia) - Electric Power Monthly with Data for January 2013 | | | | | | | | | | |

**Energy from Renewable Sources**




While not specifically a part of an unregulated or restructured power market, power from renewable sources is often included in any discussion of the transformation occurring in the power industry. Renewable power development has been significantly enhanced through Renewable Power Standards (RPS'). An RPS is a requirement for power suppliers to either procure or provide a certain minimum quantity of their total energy from renewable energy supply sources. Currently 29 states plus the District of Columbia have RPS' in the form of a goal or mandate (See chart, below).

RPS' vary widely, but generally renewable power is assumed to include power from wind, solar, biomass, hydro or geothermal sources. One state (Ohio) classifies nuclear as a renewable power source. The RPS establishes numeric targets for renewable energy supplies and seeks to encourage competition among renewable developers in meeting those targets in the least cost fashion possible. These targets are usually backed with some form of penalty if not met. Many RPS programs allow developers to utilize renewable energy certificates (REC's) to increase the flexibility and reduce the cost of compliance. Developers of non-conforming power supply projects can purchase REC's from developers that have an excess. REC's have become widespread in certain parts of the country and are electronically traded in Texas, New England, Wisconsin and within the PJM Interconnect (the Mid-Atlantic Regional Transmission Area). RPS' are designed to work in conjunction with other clean energy incentives, including federal and state clean energy tax incentives, renewable energy funds, and state integrated resource plans. California recently augmented their RPS with a cap and trade auction system for large carbon dioxide emitters.

Power industry disruption has overturned the orderly nature of this previously regulated industry and created a smorgasbord of overlapping structures. It is overly simplistic to think of power delivery in the form of regulated vs. unregulated states or traditional vs. restructured power markets. Many states are wrestling with seemingly contradictory structures. To pick just two of many examples, Oregon has chosen to become a restructured power market in order to introduce service provider competition and greater energy efficiency. They do not see the need for a power exchange given the stable nature of their hydropower. Florida, on the other hand is a traditional cost-of-service regulated state. Nevertheless, because of ratepayer dissatisfaction over the costs of failed power projects, their legislature requires cost disallowances in the case of failed, abandoned or over budget power projects. As in restructuring, this action shifts project risks from the ratepayers back to their utilities.

As was noted earlier, restructuring has created a two tier electric power industry where approximately 70% of the power consumed in the country flows through open transmission markets operated by ISOs or RTOs, while 30% is provided under the traditional cost-of-service regulated model. Restructuring has been in place for over ten years, which is a sufficient enough period of time to analyze the results and determine whether any trends are apparent.

States that opt for traditional regulation generally have experienced a lower than average cost of power and therefore do not have a "rate-of-return" bias. It is easier to justify large base load projects in these traditionally regulated states since there is a guarantee that the plant will be operated whenever it is available, that costs will be recovered and in some cases even that CWIP is available. States that opt for restructured power delivery generally have experienced a higher than average cost of power and have a strong "rate-of-return" bias. It is easier economically to provide flexible, distributed power generation in the restructured model. Perhaps nowhere in the country is it easier to see the distinction between the performance of the restructured electric power market and the regulated rate-of-return electric market than in the eight southeastern states of Texas, Arkansas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and Florida. Texas was an early adopter of open transmission access via their RTO, ERCOT. It was also an early and aggressive adopter of retail choice and utilized an RPS in order to help create a major wind power infrastructure. Texas is one of the most complete examples of a state that has adopted a restructured electric market. All of the other seven southeastern states are strong proponents of the regulated rate-of-return model.

It is, however in the plans for future capacity addition where Texas' distributed generation concept contrasts most strikingly with the traditional planning model in use in the other seven states. In the latest twenty year plan reported by the Southeast Regional Reliability Planning entity (SERC), both Georgia and South Carolina reported that they had initiated construction on a total of 4900MW of new base load nuclear generation facilities. Florida reports future plans to build approximately 2500MW of new base load nuclear and across the region approximately 12,000MW of new gas generation and 1400MW of new coal generation is planned. In the aggregate 20,800 MW of new construction is planned all of it included in the rate base. No renewable generation is included in any part of the region.

In contrast, the Texas Regional Transmission Operator (ERCOT) has a very different plan. In the "*Long Term System Assessment for the ERCOT Region dated December 28, 2012*", ERCOT has developed six different business oriented electric power scenarios. In each scenario, up to 28,000 MW of new natural gas generation capability is paired with various combinations of wind, solar and geothermal power in order to provide for overall system reliability. Prominently noted in the ERCOT report is the following: "*The capital costs for pulverized coal, integrated gasification combined cycle, and nuclear units are too high for them to be competitive under the future scenarios evaluated*". ERCOT is planning the addition of around 50,000 to 70,000 MW of competitively supplied distributed generation. All the project risk is retained by the bidders and not the Texas electricity ratepayer. Further, since the individual Texas projects are relatively small and dispersed across a twenty year timeline, ERCOT retains the option, and indeed intends to modify its plans on an on-going basis as technology and business conditions change.

The future stakes are large; globally the power industry is the largest single industry in the world. In the United States alone it generates $737B in annual revenue and nearly 3% of GDP. As the industry and regulators attempt to come to grips with the issue of providing stable low cost retail power options, several significant changes have recently occurred that have the potential to significantly change the way power is generated in the United States.

The power industry is undergoing structural and technological transformation comparable to other large network oriented industries. Like the computer and telecommunications industries, power generation is becoming less centralized. Moderate natural gas prices make combined cycle gas turbine generators competitive with much larger thermal power generators. Automated metering has introduced two way communications between power suppliers and their customers, creating the opportunity for greater network monitoring efficiency and demand response management. PC's, and now smart phones and tablets enabled distributed information processing. "Point of sale" data capture allowed the retail industry to radically re-structure its distribution model, and centralized ticketing permitted the airline industry bypass the "hub-and-spoke" terminal model in favor of more efficient point-to-point routing based upon ticket price yield analysis. The fact that automated metering is introducing two way communications between power suppliers and their customers, creates the potential for greater customer driven power supply efficiency and service.

# Lazard

# Levelized Cost of Energy (LCOE) V.9.0

July 19, 2016

Albany Sustainability Committee
c/o Claire Griffing – Sustainability Coordinator

Thank you for the opportunity to comment on the draft "Technical Study for Community Choice Aggregation Program in Alameda County". My general impression is that the study is a through and fair-minded analysis of complex issues. This is no surprise: The primary contractor, MRW and Associates, is well-regarded by everyone I know in the electricity business. Below I suggest some minor additional work that may help in interpreting their results and assisting the discussion of the Alameda CCA.

- Include a historical comparison of electricity rates charged by PG&E and other CCAs. The expectation of lower rates was part of the appeal of each CCA. How has that worked out?
- For each scenario, include an estimate of the change in Greenhouse Gas emissions for the entire Northern California electricity sector, relative to the Base Case. In one scenario in the Technical Study, attribution of GHG emissions shifts from one entity to another, but there may be no overall reduction in emissions.
- Address in greater detail the operational concerns stated by the California Independent (Grid) Operator, or CAISO, regarding additions of solar electricity and possible curtailment of solar generators.
- Include two additional sensitivity cases on the assumed shutdown of the Diablo Canyon nuclear plant.

Each of these suggestions is described below. At the end, I present an analogy between the electricity grid and a tandem bicycle. I assume that people discussing the CCA understand how the grid works. However, newcomers (like me when I began work in the electric industry) may be assuming that the electricity grid works like Amazon or FedEx, e.g., I sign up for solar electricity and the grid delivers it to me. This is incorrect, and the correct view has policy implications.

Once again, thank you for the opportunity to comment.

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**Historical Comparison of CCA and PG&E Rates**

Formation of each existing CCA was accompanied by an expectation of electricity rates lower than those charged by PG&E. How did that turn out? I was unable to find a comprehensive historical comparison. Instead, I found two snapshots. One shows what I expected: Sonoma Clean Energy's current monthly electricity bills are roughly 5% to 10% lower than those of PG&E. The other snapshot was surprising: Marin Clean Energy's bills are currently 5% to 10% higher than PG&E's. It would be helpful to have more than two data points.

Developing a complete historical comparison may be challenging, but MRW clearly has the expertise to do it, though it may require an addendum to the consulting contract.

> The comparisons of monthly bills are at these links:
> https://sonomacleanpower.org/wp-content/uploads/2015/11/2015-09-01-SCP_Joint-Rate-Comparison.pdf
> http://www.pge.com/includes/docs/pdfs/myhome/customerservice/energychoice/communitychoiceaggregation/mce_rateclasscomparison.pdf

**GHG Emissions from Northern California's Electricity Sector**

In the Technical Report, two scenarios appear to change the attribution of GHG emissions among different entities in Northern California, without major changes in total emissions from that sector. Adding estimates of electricity-sector GHG emissions to the Technical Study would clarify important results from Scenario 1 and Scenario 2.

For Scenario 1, the Technical Study states that:

> "there are no greenhouse benefits for Scenario 1 [for the Alameda CCA]—in fact there are net incremental emissions" (p. vii).

This statement seems unduly pessimistic. It appears that in Scenario 1, customers leaving PG&E to join the Alameda CCA are no longer credited with a share of PG&E's GHG-free electricity (hydro and nuclear), but there is no change in overall emissions.

In Scenario 1, the Alameda CCA meets 33% of its customers' demand with renewables, and meets the other 67% with purchases of non-renewable electricity from the wholesale market. This treatment increases the GHG emissions attributed to the customers who leave PG&E to join the Alameda CCA, because they are no longer credited with shares of PG&E's GHG-free electricity. However, Alameda's purchases of non-renewable electricity are offset by reduced purchases by PG&E, because it has fewer customers than in the Base Case.

A similar observation applies to Scenario 2, where it is more important. The Technical Study notes that

> "The Alameda CCA's GHG emissions under Scenario 2 are much lower than those under Scenario 1. This is due to the higher renewable content in the CCA's generation mix under Scenario 2, but more importantly, the 50% hydro content in the non-renewable generation mix." (p. vii, emphasis added)

In other words, the Alameda CCA has lower GHG emissions in Scenario 2 than in the Base Case or Scenario 1 partly because it builds or pays for construction of more GHG-free generators. This is "steel in the ground", and causes a drop in the GHG emissions of the Northern California electricity sector. So far, so good, but how about that more important part--the "50% hydro content in the non-renewable generation mix".

To the best of my knowledge, all of California's good sites for hydroelectric generators are already being used, so new hydro is not an option. The Technical Study may be assuming that, when an existing contract to sell hydroelectricity expires, the Alameda CCA will outbid other CCAs and utilities to sign a new contract in order to achieve "50% hydro content". This is how I interpret the statement in the Technical Study that "if carbon reductions are a high priority for the CCA, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed" (p. xiii).

If my interpretation is correct, Scenario 2 assumes that the Alameda CCA would outbid competitors for electricity from existing hydroelectric plants. Outbidding would change the allocation of GHG emissions among parties in Northern California, without any change in the total GHG emissions.

It seems reasonable to assume aggressive bidding by many entities for hydroelectricity when current contracts expire. The Alameda CCA could be trying to outbid the Marin and Sonoma CCAs and utilities including PG&E, the Sacramento Municipal Utility District, Palo Alto, Modesto, Turlock and others

**CAISO's Operational Concerns**

The California Independent [Transmission] System Operator, or CAISO, has repeatedly expressed concern about its ability to provide reliable service due to operational difficulties caused by increasing additions of solar generators. This concern may be relevant to the Alameda CCA because CAISO can address it partly by forcibly "curtailing", or disconnecting solar PV from the grid.

The CAISO's concern is complicated and hard to explain, and even harder to analyze. Here is a description by the National Renewable Energy Laboratory of the CAISO's concern:

> "In 2013, the California Independent System Operator (CAISO) published a chart showing the potential for "overgeneration" occurring at increased penetration of solar photovoltaics (PV). The "duck chart"[2] shows the potential for PV to provide more energy than can be used by the system, especially considering the host of technical and institutional constraints on power system operation.
>
> During overgeneration conditions, the supply of power could exceed demand, and without intervention, generators and certain motors connected to the grid would increase rotational speed, which can cause damage. To avoid this, system operators carefully balance supply with demand, increasing and reducing output from the conventional generation fleet. The overgeneration risk occurs when conventional dispatchable resources cannot be backed down further to accommodate the supply of variable generation (VG). Overgeneration has a relatively simple technical solution,

> often referred to as curtailment. Curtailment occurs when a system operator decreases the output from a wind or PV plant below what it would normally produce."
>
> Source: "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart", November 2015, at http://www.nrel.gov/docs/fy16osti/65023.pdf

The Technical Study may not directly address the CAISO's concern. The Study does address hours when the Alameda CCA's renewable generators produce more electricity than its customers are using (pp. 11-12 and Appendix B-3), but it's not clear whether that approach addresses the problem at the grid level. If the Alameda CCA and other entities collectively build "too much" solar PV, the CAISO may accommodate electricity from Alameda's PV units by curtailing PV units owned by other entities.

I suggest that the Technical Study examine the possibility of curtailment of solar PV units, whether owned by the Alameda CCA or other entities. Curtailment might be a problem, especially if Alameda pursues a 100% renewable portfolio based largely on solar PV.

**Sensitivity Study: Replacement of Diablo Canyon Nuclear Power Plant**

The Technical Study assumes that PG&E retires Diablo Canyon Units 1 and 2 when their operating licenses expire in 2024 and 2025. The Technical Study apparently assumes that PG&E replaces Diablo with GHG-emitting electricity:

> The expected retirement of Diablo Canyon in 2025 increases PG&E's emissions by approximately 30% in 2025. (p. vii)

Would it be reasonable to include a sensitivity case in which PG&E replaces Diablo with renewable sources? Such a sensitivity case would presumably raise the Study's forecast of PG&E rates and cut its forecast of PG&E's GHG. It would be useful to see quantitative results.

**Sensitivity Study: Extension of Diablo Canyon Operation**

To justify the assumed retirement, the Technical Study cites several costs, notably a cost of $4.5 billion cost to install cooling towers "per state regulations implementing the Federal Clean Water Act" (p. C-3). This assumption is included in the Base Case and Scenarios 1 and 2, and clearly it deserves that treatment. Is it conceivable, however, that the impacts of climate change over the next several years cause a shift in public opinion and the law to promote relicensing? Would it be reasonable to perform a sensitivity case in which PG&E's cost to relicense Diablo is, say, $1 billion because of a change in the law?

**Tandem Bicycle Analogy to the Electricity Grid:**

Newcomers to electricity issues sometimes assume (as I once did) that the electricity grid works like Amazon or FedEx: I order a parcel of, say, electricity from solar panels, and, supposedly, it is delivered through the grid to my house. The reality is more complicated, and has policy implications. The analogy between the electricity grid and a tandem bicycle may help.

Imagine a long tandem bicycle, with many seats, ascending a long, even grade. Suppose that it must be kept ascending at a constant speed (e.g., because traveling faster or slower would cause excessive vibration). Some people (representing generators) are pushing on their pedals, providing mechanical energy to propel the bicycle. Others are passengers (representing demand or "load") who are free to jump on or off.

As passengers jump on or off, the pedalers must collectively adjust how hard they press on the pedals to keep the bicycle moving at a constant speed. If one pedaler suddenly stops pressing on the pedals, others have to press harder to maintain a constant speed.

Now suppose that new pedalers are added, but the new pedalers push hard on the pedals only when the sun breaks through the clouds. At those sunny times the other pedalers have to push lightly on the pedals, or not at all, to prevent the bicycle from achieving excessive speed.

In the terms of this analogy, the CAISO's operating concern is that, as more solar "pedalers" are added, their pedaling occasionally overwhelms the collective ability of other pedalers to back off. One solution is curtailment of the solar pedalers: The CAISO disconnects some pedals from the tandem bicycle's chain, thereby wasting some potential renewable electricity and not realizing its environmental benefits.

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Thank you for considering these comments.

Sincerely,
Mark Meldgin
Albany CA

Notes:

1. The draft Technical Study and draft Appendices are at the following links: https://www.acgov.org/cda/planning/cca/documents/Feas-TechAnalysisDRAFT5312016.pdf and https://www.acgov.org/cda/planning/cca/documents/Feas-TechStudyappendices05312016.pdf
2. The tandem-bicycle analogy is presented in greater detail, aimed at an engineering audience, at this site: http://www.leonardo-energy.org/sites/leonardo-energy/files/root/Documents/2009/ElectricityTandem.pdf

## Rivera, Sandra, CDA

**Subject:** FW: IBEW comments - MRW Work Papers

**From:** Stern, Hunter [mailto:hls5@IBEW1245.com]
**Sent:** Saturday, June 18, 2016 7:01 PM
**To:** Rivera, Sandra, CDA <sandra.rivera@acgov.org>; Jensen, Bruce, CDA <bruce.jensen@acgov.org>; 'mef@mrwassoc.com' <mef@mrwassoc.com>
**Cc:** 'Uno, Victor' <Victor_Uno@IBEW.org>
**Subject:** RE: IBEW comments - MRW Work Papers

Sandra,

Again thanks for the extra hours to submit these comments. More importantly, thanks to the County and MRW for making these Work-Papers available for review. This has given clear insight into the information contained MRW draft report and updated draft.

The "Big Picture" take away from these Work Papers is that the MRW Technical-Feasibility report errs in its approach and analysis. Partly, there is inadequate or missing documentation that does not substantiate the information and apparent conclusions made by the Report. But the fundamental error is the approach.

The MRW report is no more than a single snapshot of a series of single predictions regarding future PG&E rates, future cost of solar power, future cost of power from local renewable projects and numerous other distinct data points. In fact, these data points are, in most cases, no better than 'guesses and the resultant conclusions are entirely unreliable. The failure of this review and others associated with decisions to launch Community Choice Aggregation public agencies in Marin, Sonoma and San Mateo is that the Technical-Feasibility report relies on unsubstantiated estimates as if they are fact and then concludes to advise Alameda County that the CCE will be successful and should launch.

In fact, a proper Technical-Feasibility report should be made via Probability Analysis. Probability Analysis can take the variables of the needed data points, utilize these variants to include the likely value of each data point and then combine these probabilities to create an accurate determination of the likelihood that an Alameda CCE will achieve the desired objectives. The IBEW strongly urges that the Peer Review of the MRW Study include Probability Analysis of the information gathered by MRW as well as including the information missing which is needed to complete the analysis.

Here are specific comments on the Work Papers:

1. MRW uses Sonoma Clean Power (SCP) data for base A&G assumptions yet SCP has not met its promises/expectations of high RPS content (SCP has only 33% RPS), has not built any local projects (that I know of), and is in a dead heat with PG&E rates. Further, SCP was caught completely off guard by the PCIA increase, which, with adequate technical assistance, SCP should have been able to predict. Unless Alameda wants a track record like SCP, SCP A&G assumptions are not reliable.
2. "Admin Costs" at tab "Detail" F7-F11 states "these are just guess/placeholders" for $1.2mm in Admin Costs. On what basis is this guess made? Marin Clean Energy (MCE) has claimed as much as $2.5 Million in start-up costs. San Joaquin Valley Power Authority spent more than $2 Million. SCP has never discussed their costs but as the planning and project work was done by the Sonoma County Water Agency and they reportedly spent $1.5 million in its work. How can this be a guess and why use $1.2 Million. Given that the County has contracted for this work, we should expect more than guesses and placeholders for costs in the millions.

3. "PG&E Rate Model" at tab "PG&E Capacity Forecast" B10 states "Note: CPUC's October 2015 Scenario Tool in Long Term Procurement Proceeding (R.13-12-010) shows total system supply of 115.4% of system demand in 2035; we have assumed that new capacity will therefore be needed beginning in 2036 and that the tight capacity supply will begin to increase capacity prices in 2030" The presumptive impact of this assumption is that PG&E will pay more for capacity in 2030, but is that applied to CCA too? If so, where is it applied in the MRW analysis and how? If not, why? Besides, there is reason to believe this information is inaccurate. Most experts believe the push for increased renewable energy under SB350 will drive a need for more flexible capacity to replace baseload capacity, not necessarily increase capacity prices in general.
4. The Pro Forma assumes 15% opt outs. On what basis? MCE had its customers opt-out at over 20% rate for its first few years and has trended toward 25%. SCP has had its customers thus far trend to 15% opt-out rate. (Without any information that SCP is not achieving all its objectives. In short, a 20% Opt-Out rate should be the rule of thumb for essential service default programs.
5. We need further direction or clarity on the information MRW used to calculate greenhouse emission rates. We can't find specific information in the Work Papers that would substantiate the estimates given. Specifically, what is the baseload portfolio mix on non-renewable power that was used?
6. Previously, the IBEW questioned the voracity of the wind and solar future costs. We cannot find the basis of these estimates unless MRW has included the use of unbundled RECs, reducing the overall power costs.

Please advise as to the information MRW used for projected GHG emissions rates and whether the use of unbundled RECs are part of the analysis and in what amount.

Kind Regards,

Hunter Stern
IBEW Local 1245