Peer Review of the Peninsula Clean Energy CCA Technical Study

On Behalf of the County of San Mateo

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February 23, 2016

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Executive Summary

In 2015, Pacific Energy Advisors, Inc. (PEA) prepared a Community Choice Aggregation (CCA) Technical Study (Study), describing the potential benefits and liabilities associated with the formation of Peninsula Clean Energy (PCE), which would provide electric generation service to residential and business customers located within the twenty municipalities in the County of San Mateo (County) as well as unincorporated areas of the County. The Study evaluated projected operations of PCE, over a ten-year planning horizon, considering such factors as PCE's ability to offer rates competitive with Pacific Gas & Electric (PG&E); increased use of renewable energy sources; reduced emissions of greenhouse gases (GHG) and local and statewide employment and economic impacts.

In late 2015, the County retained MRW & Associates, LLC (MRW) to conduct a peer review to assess the soundness and thoroughness of the technical analysis, as well as the reasonableness of the underlying assumptions. MRW was also asked to provide any additional information that might be useful to the County and PCE decision makers. The following is MRW's professional review of the Study.

Overall, MRW finds that the Study was thorough and professionally performed. We found no "fatal flaws" or major assumptions that require revision. As noted here, there are a few areas that may benefit from clarification, expansion or revision, but overall the Study is sound.

Even though the Study finds that the CCA would be cost-competitive under a wide range of assumptions over the 10-year period, given ratemaking in California, it is likely that in an isolated year, PG&E's rates will be less than the PCE's average cost of service. This can be addressed both through sufficient rate stabilization reserves and good communications with its customers.

The remainder of the executive summary presents MRW's responses to the specific questions listed in the County's request for proposals.

1. Does the study consider all pertinent factors to determine current and future electric energy requirements of the CCA?

Yes. Overall, MRW found that the Study was thorough and considered all the necessary parts to evaluate the energy requirements of PCE.

2. Does the study incorporate current power market conditions and reasonable projections of expected future conditions?

In general, the power market assumptions are reasonable. As discussed in more detail under Question 6, MRW found that the timing of the long-term renewable contracts assumed in Study to be overly optimistic. Nonetheless, MRW does not believe that this would impact the overall results of the Study.

3. **Considering the difficulty in accurately estimating greenhouse gas (GHG) emissions attributable to a given electricity supply portfolio, are the estimates of the GHG emissions intensity of the CCA scenarios relative to PG&E reasonable and adequate?**

Yes, MRW finds estimates of the GHG emissions intensity of the CCA scenarios and PG&E reasonable and adequate.

4. **Does the study consider all pertinent factors in projecting future PG&E rates for comparison to CCA costs/payment projections?**

While MRW did not have access to PEA's PG&E rate forecasting model, its outputs were reasonable and its results are generally consistent with recent forecasts performed by MRW. In addition, the Study appropriately addressed the likely retirement of PG&E's Diablo Canyon Nuclear Power Plant in 2022-2023.

5. **Does the study consider all pertinent factors in presenting a reasonably accurate investor-owned utility (IOU) vs. CCA cost/payment comparison?**

Yes. The input variables into the PG&E rates and CCA costs are complete and generally reasonable.

6. **Do the pro forma analyses consider all pertinent factors in projecting CCA's operating results? Do the pro form analyses include reasonable cost-of-service variables?**

Yes, the pro forma analysis includes all pertinent factors in projecting CCA's operating results as well as generally reasonable cost-of-service variables.

The schedule for the implementation of new renewable resources is overly optimistic and not likely to be met. For example, acquiring 100 MW of utility scale solar PV by 2019 is not likely. Utility-scale projects do not get constructed without a sales agreement in place, which do not occur without the necessary permits in hand and a place in the CAISO interconnection queue, which is currently at 34,655 MWs of projects desiring to connect to the grid. Thus, the facility or facilities underlying the 100 MW would have to be associated with projects that already have all their requisite permits in place and a place in the CAISO interconnection queue. (This is in fact likely what PEA was considering in its projection.) A contract would need to be signed quickly, once the CCA is established, so that the developer(s) can begin construction and deliver power by 2019. Even this might be challenging, given that banks that could fund the project(s) for the developer might find the counterparty risk associated with a brand-new entity to be too great.

7. Do you have any other suggestions for reducing CCA costs under a traditional California CCA formation scenario?

MRW has no suggestions. The Study identified the key cost components, their underlying activities and functions, and provided reasonable estimates for those components.

8. Does the study present an adequate analysis of potential economic benefits and challenges of various supply scenarios? Does the study present a reasonable assessment of job creation, both total jobs created and local jobs created?

The Study used a reasonable tool, the Jobs and Economic Development Impact ("JEDI") model, to estimate the employment and economic impacts of the assumed PCE-sponsored renewable energy projects. MRW finds the results to be reasonable to an order of magnitude. Nonetheless, the way that the Study characterized the economic and job impacts was misleading. In multiple places in the Study, the economic impacts were characterized as "significant," both statewide and for San Mateo County. While the impacts are undoubtedly positive, they are better described as "modest." When viewed statewide, the jobs and economic impacts resulting from the PCE renewable supply projects would be miniscule; literally orders of magnitude smaller than any significant figure presented by the California Department of Finance or the US Bureau of Labor Statistics. Furthermore, most (but not all) of the new renewable generation projects will occur outside of the County. Thus, the local economic and employment impacts will also be positive, but still only modest.

MRW concurs with the Study that PCE would have little to no impact on the PG&E workforce.

9. Should any additional benefits or challenges be considered?

MRW does not believe that any major additional benefits or challenges need be considered. As discussed in more detail below, a few additional rate sensitivity runs should be conducted to explore the likely challenge of meeting the schedule set for new renewable project development and variations in greenhouse gas allowance prices.

However, MRW finds that one additional risk should be explicitly addressed. CCAs must carry insurance or post a bond that will cover the cost to PG&E if the CCA were to suddenly fail. Currently, a bond amount for CCAs is set at $100,000, the value used in the Study. However, this $100,000 is an interim amount. If the CPUC takes up the issue again and the CCA bonding requirement follows that set for Energy Service Providers (ESPs) serving direct access customers, the amount could increase over tenfold.

While this risk is mentioned in the Study (p. 44) it is lumped into "regulatory risk." MRW believes that this risk should be explicitly included in the "PCE Risk and Mitigation Matrix" with a Likelihood of "Low," an Impact of "Medium" to "High" and a Level of Risk/ Impact of "Medium."

10. Does the study provide a thorough evaluation of the prospective CCA's ability to achieve rate competitiveness with PG&E? What other factors, if any, should be considered?

The Study is thorough in evaluating the CCA's ability to achieve rate competitiveness. The variables tested in the sensitivity analysis, along with the assumed values for those variables, were all appropriate. Nonetheless, it would be useful to see the year-by-year results for the sensitivities. By presenting the sensitivity results solely as a 10-year levelized cost, one cannot see pertinent trends. These might include CCA average costs exceeding PG&E rates in early years but being low enough in later years so as to generate a positive levelized value. Or the PG&E and CCA rate projections could cross each other in a later year, so that if a longer time-frame was considered the results would be different.

MRW recommends that PEA identify any sensitivity cases where the PG&E and CCA rate lines "cross," present those results, discuss the likelihood of that case coming to fruition, and describe how the CCA might address that risk.

11. Does the study consider all pertinent factors to assess the overall cost-benefit potential of CCA?

The Study addressed all the pertinent factors needed to assess the overall cost-benefit potential of PCE. MRW recommends that PEA conduct an additional set of rate sensitivity runs exploring higher and lower greenhouse gas allowance costs and a more conservative timeline for the implementation of power purchase agreements (PPAs) associated with new renewable project development.

12. Does the study consider all pertinent risk factors involved with establishment and operation of the CCA program, and are such factors properly weighted and analyzed?

Overall, the risk analysis was thorough and provided appropriate responses to the risks identified. Please see response to Question 9 above for a recommendation for an additional risk factor to consider.

13. Does the study provide an adequate analysis of the liabilities to the members of the CCA?

The member communities can be shielded from the liabilities of the PCE through proper Joint Powers Authority (JPA) formation and bylaws. With three operating CCAs, MRW believes that good "templates" exist for such documents of which PCE should take advantage.

14. Are the assumptions made in the study reasonable and adequate?

With the minor exceptions discussed above, the assumptions are reasonable and adequate.

Introduction and Background

In 2015, Pacific Energy Advisors, Inc. (PEA) prepared a Community Choice Aggregation (CCA) Technical Study (Study), describing the potential benefits and liabilities associated with the formation of Peninsula Clean Energy (PCE), which would provide electric generation service to residential and business customers in the twenty municipalities in the County of San Mateo (County) as well as unincorporated areas of the County. The Study evaluated projected operations of PCE, over a ten-year planning horizon, considering such factors as PCE's ability to offer rates competitive with Pacific Gas & Electric (PG&E); increased use of renewable energy sources; emissions of greenhouse gases (GHG), and local and statewide employment and economic impacts.

In late 2015, the County retained MRW & Associates, LLC (MRW) to conduct a peer review to assess the soundness and thoroughness of the technical analysis, as well as the reasonableness of the underlying assumptions. MRW was also asked to provide any additional information that might be useful to the County and PCE decision makers. The following is MRW's professional review of the Study.

Overall, MRW finds that the Study was thorough and professionally performed. We found no "fatal flaws" or major assumptions that require revision. As noted here, there are a few areas that may benefit from clarification, expansion or revision, but overall the Study is sound.

Even though the Study finds that the CCA would be cost-competitive under a wide range of assumptions over the 10-year period, given ratemaking in California, it is likely that in an isolated year, PG&E's rates will be less than the PCE's average cost of service. This can be addressed both through sufficient rate stabilization reserves and good communications with its customers.

The remainder of the report is organized by topic: demand forecast, supply assumptions, other operating costs, PG&E fees, sensitivity analysis, economic and employment analysis, and risk assessment.

Demand Forecast

PEA based its demand forecast upon the baseline consumption from the PG&E load data and the California Energy Commission's forecast of load for the Bay Area from 2015 to 2025.[1] From that forecast, the Study assumed a 0.5% annual growth rate, which is lower than the CEC base forecast (1.2%) so as to account for additional energy efficiency. This is a credible source for forecasting purposes, and PEA's energy efficiency adjustment is reasonable.

PEA also removed the Direct Access load from the forecast, assuming that those customers would remain on DA service and not join the CCA. PEA further assumed a 15% customer opt-out rate for its Supply Scenarios 1 and 2. This opt-out rate is generally consistent with the reported opt-out rates observed during recent expansions of the Marin Clean Energy program as

[1] Kavalec, Chris, 2015. California Energy Demand Updated Forecast, 2015-2025. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-2002014-009-CMF, Table 6.

well as that for Sonoma Clean Power. For supply Scenario 3, which relies exclusively on bundled renewable energy products to meet PCE's load, PEA assumed that the resulting higher rates would cause increased opt-outs of 25% for all residential and small commercial customers and a 50% for all other customers groups. Sensitivities using different opt-out rates were also explored.

In combination with the sensitivities, these overall opt-out and load forecast assumptions are reasonable for the pro-forma analysis.

The Study notes that the hourly electricity consumption and peak demand were estimated using hourly load profiles published by PG&E for each customer classification. This is a reasonable source. However, these profiles are system-wide, and as such would likely overstate the peak demand for San Mateo County, as its air conditioning load is low relative to the PG&E territory overall. Overestimating the peak demand would result in conservative (i.e., high) cost estimates for meeting resource adequacy requirements.

Supply Assumptions

This section presents MRW's comments on the key elements of the supply forecast: renewable and non-renewable power prices, resource adequacy prices, associated greenhouse gas (GHG) costs, and the phasing in of PCE power purchase agreements with specific renewable assets.

Non-Renewable Power and Underlying Gas Prices

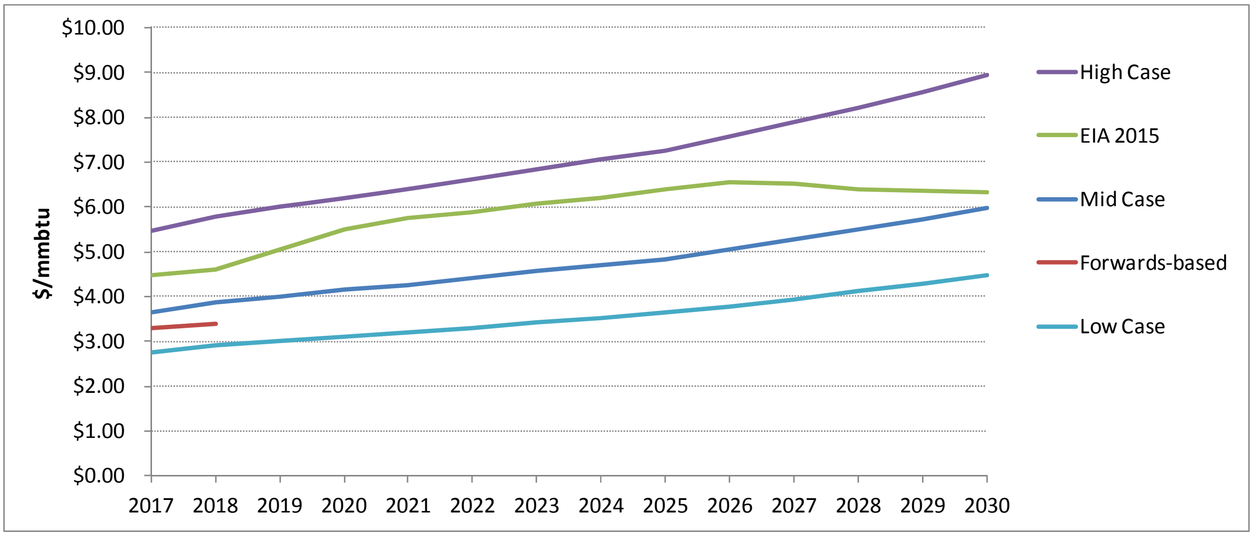
The Study assumes that the market cost of power equals the annual average price of gas times a "market heat rate" plus any associated GHG compliance costs. On-peak power prices are assumed to be 15% higher than this annual average and off-peak prices are assumed to be 10% below the average. Given that natural gas generators are on the margin in the CAISO system a majority of hours and thus set market prices, this method is reasonable.

The Study uses a market heat rate of 8,000 Btu/kWh. This rate falls between that of a combustion turbine, which would set the wholesale power market price at times of higher demand, and a newer combined cycle power plant, which would set the wholesale market price most other hours. MRW finds the 8,000 Btu/kWh to be a bit high, given that the continuing large influx of renewables that is occurring (and will continue to occur through 2030) will pull down the market heat rate -- i.e., more efficient plants will be on the margin. This means that for the given gas price forecast, the Study's market price forecast may be on the order of 5-10% too high. Nonetheless, given the uncertainty of gas prices, along with the sensitivity analyses conducted, this difference does not affect the overall conclusions of the Study.

Figure 1 below shows the natural gas price forecast underlying the Study's power price forecasts, along with two benchmarks: the average prices to electric generators from the Energy Information Administration's 2015 Annual Energy Outlook, and the 2017 and 2018 futures prices for natural gas at PG&E's city gate. As the figure shows, both the benchmarks are within the sensitivity range used by PEA. Note that the EIA 2015 data is significantly higher than the

Study's Mid Case (although still lower than the Study High Case), due in all likelihood to the continued fall of natural gas prices since the EIA forecast was produced in late 2014/early 2015.

Figure 1. Natural Gas Price Forecasts



The Study assumed a GHG emissions rate of 0.428 ton/MWh for market power. This emissions rate falls between that of a gas-fired combined cycle (0.38 ton/MWh) and a combustion turbine (0.50 ton/MWh) and is reasonable.

Resource Adequacy (RA) Costs

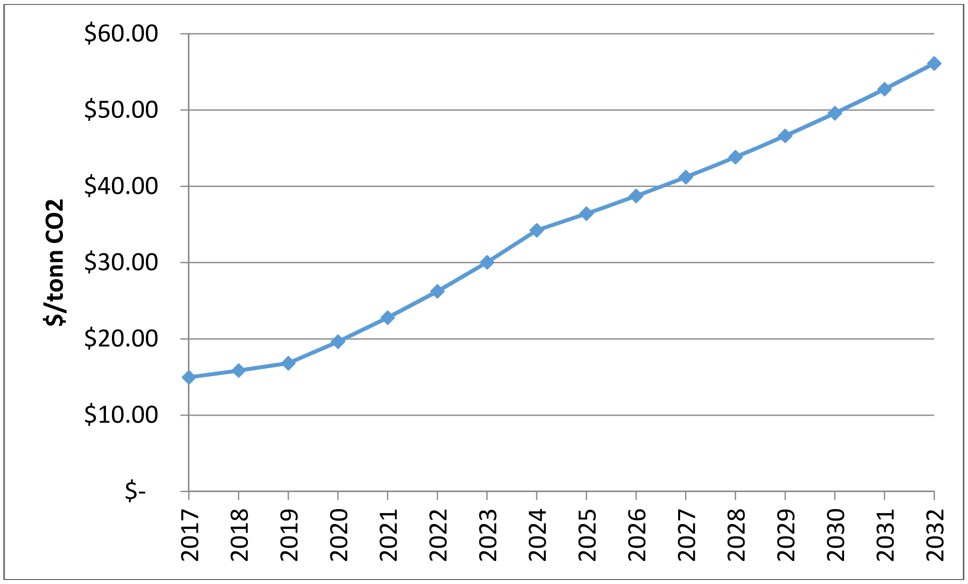
Any CCA program must demonstrate it has sufficient physical generating capacity to meet its projected peak demand plus 15% (resource adequacy or RA requirement). For PCE a certain portion of generating capacity must be located within certain local reliability areas ("Local RA") with any remaining capacity requirement met with generators anywhere within the California Independent System Operator CAISO system ("System RA"). In the report, PEA identified which portions of the County fell into areas that require Local RA.

In the pro forma, the Study assumes an RA price of approximately $17/kW-year in 2015, escalating at 3% thereafter. The pro forma does not separate out for different pricing the Local RA from the System RA. In practice, the price of Local RA can be greater than the System RA. This detail is thus not modeled. In addition, the starting value of $17/kW-year appears low, although not so low as to impact the pro forma analysis. Nonetheless, even if PEA is understating RA costs, it would not make a difference in PEA's overall conclusions because the RA costs are a relatively small fraction of the total.

GHG Prices

Figure 2 shows the Study's projected cost of GHG allowances. The Study assumes that allowance price begins at $13.43 per metric ton ($/ton) and escalates at around 6% per year, with the exception of 2020 through 2025, where it escalates at 14%-17% per year. The Study's implicit forecast for 2016, $14.16/ton is higher than the actual January 2016 California carbon allowance price, of $13.20/ton.

Figure 2. CO_2 Allownace Price Foreacst

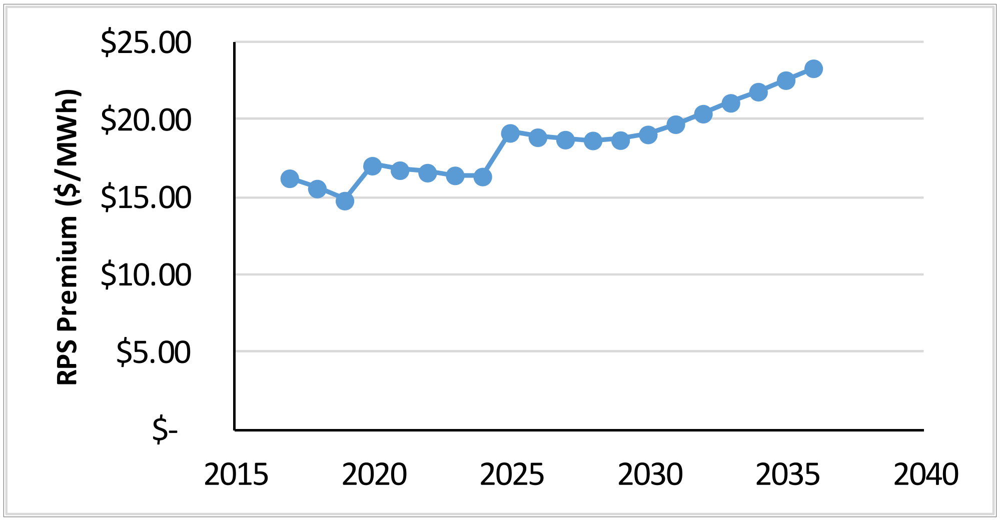


Forecasting the price of carbon allowances is highly uncertain. For the past 2 to 3 years, the allowances have remained at or near the California Air Resources Board's (CARB's) auction reserve price. This reserve price escalates at 7% per year through 2020. Thus, the very near term values are likely reasonable. Beyond 2020 the prices are much more uncertain. PEA should provide its rationale for the significantly higher escalation rates in 2020 through 2024.

Renewable Power

Market Renewable Power. PEA set the value of market renewable power (Bucket 1) as a premium over the standard market power price. Thus, the price of market renewable power will follow the general price of power plus the premium. The assumed RPS premiums are shown in Figure 3. The "saw tooth" shape through 2030 is caused by assumed decreases in renewable prices exerting downward pressure, and Renewable Portfolio Standard compliance dates (33% by 2020, 50% by 2030) exerting upward pressure.

Figure 3. Renewable Power Price Premium



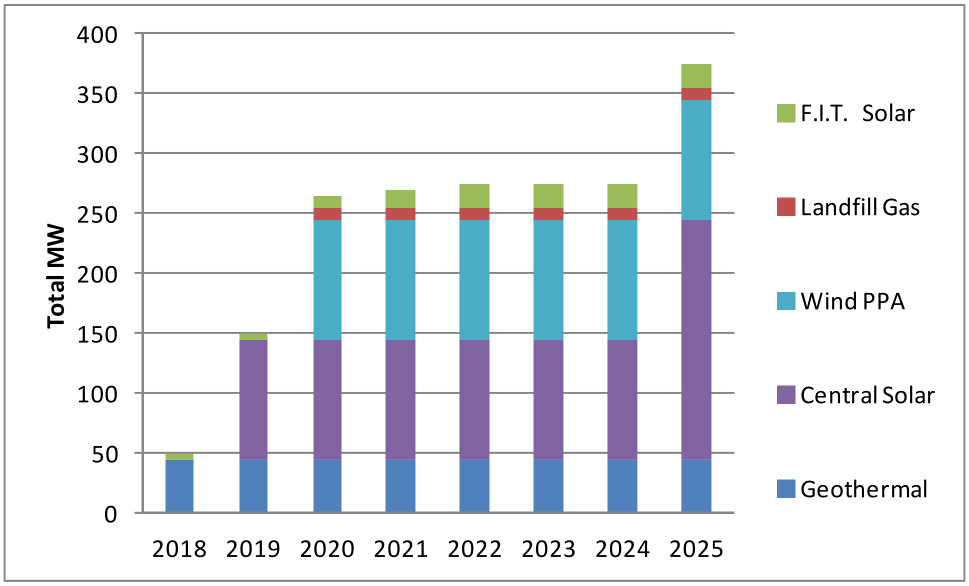
The long-term PPAs for renewable power assumed in the Study are shown in Table 1 and Figure 4. The prices for the large ground solar PV, wind and geothermal are reasonable and consistent with the current markets. As discussed below, the price for the feed-in tariff (FIT) solar power may be too low to generate the capacity additions assumed.

Furthermore, the Study assumed that the federal Investment Tax Credit (ITC) would decrease from 10% to 30% in 2017, which did not occur. Instead Congress authorized an extension of the 30% ITC through 2019, with it decreasing to 25% in 2020, 22% in 2021, either zero of 10%, depending upon ownership structure, thereafter. By assuming the lower ITC rate, the Study's costs for renewables become conservative.

Table 1. PCE Renewable Additions

	Capacity (MW)	Price ($/MWh)	Load Shape	Year in Place
Solar PV, Central Valley, large ground	100	$65	PV	2019
Solar PV, Central Valley, large ground	100	$65	PV	2025
Wind	100	$70	WIND	2020
Landfill Gas	10	$80	7 X 24	2020
Geothermal	45	$80	7 X 24	2018
Solar PV, FIT	5	$100	PV	2018
Solar PV, FIT	5	$90	PV	2020
Solar PV, FIT	5	$90	PV	2021
Solar PV, FIT	5	$90	PV	2022

Figure 4. PCE Renewable Additions



The Study's schedule of renewable additions is very aggressive and is likely not to be met. The initial 45 MW of geothermal power would have to come from the geysers or other existing facility. MRW finds this to be likely attainable. The 10 MW of landfill gas is also likely attainable, particularly if the landfill gas generator is already in existence, or at worst, already permitted.

Acquiring 100 MW of utility scale solar PV by 2019 is not likely. Utility-scale projects do not get constructed without a sales agreement in place, which do not occur without the necessary permits in hand and a place in the CAISO interconnection queue. Thus, the facility or facilities underlying the 100 MW would have be projects that have all their requisite permits in place and a place in the CAISO interconnection queue. A contract would need to be signed quickly once the CCA is established so that the developer(s) can begin construction to deliver power by 2019. Even this might be challenging, given that the banks or investors that would fund the project for the developer might find the counterparty risk associated with a brand-new entity to be too great.

While this is daunting, getting at least some of that 100MW in place by 2019 is attainable. The response to the California utilities' "Renewable Auction Mechanism" (RAM), a CPUC-prescribed solicitation for renewables under 20 MW, received many times more offers than they were able to sign contracts. Thus, there are likely developers with viable projects who were not selected in the RAM and are thus looking for another off taker. It is from this pool of candidates that the 2019 solar—and to a lesser degree, the 2020 wind power—will likely come from.

The feed-in-tariff amounts also appear overly optimistic. For the past two years, San Mateo County has been adding approximately 8 MW per year of net-energy metered (NEM) solar PV. These installations have been primarily using a lease/PPA model, and thus having the developer bear the financing. Since NEM is valued at retail rates, this means that the effective price the leaseholders (or homeowners) are receiving is approximately 20¢/kWh. That is, by offsetting 20¢/kWh retail rates, value of a solar panel is 20¢/kWh to the homeowner or panel owner. Thus, the FIT would be attracting 63% as much solar PV at 9¢/kWh as the NEM installations at 20¢/kWh. Unless there is a major market change in solar NEM policy (which is not unthinkable) and firms that currently do utility-scale solar or rooftop solar become interested in FIT-sized installations at 9¢/kWh, MRW is skeptical that the FIT targets can be met.

Transmission and Grid Services

The CAISO charges all entities that use its grid for the transmission and grid management services that it performs. These include costs of managing transmission congestion, acquiring operating reserves and other "ancillary services," and conducting CAISO markets and other grid operations. These charges amount to roughly 5-6% of the procurement costs. The values used by PEA are reasonable.

Other Cost of Service Elements

While power procurement costs are by far the greatest expense, PCE will incur a number of overhead and operating expenses. The Study used reasonable estimates of these costs, consistent with that seen by the operating CCAs.

PG&E Fees paid by CCA Customers

PG&E imposes two surcharges that are unique to CCA and direct access customers: the Franchise Fee Surcharge and the Power Charge Indifference Adjustment (PCIA). These surcharges are not program costs *per se*, but impact how a customer's bill will compare between PG&E bundled service and CCA service. The franchise fee surcharge is a minor charge that ensures PG&E collects the same amount of franchise fee revenues whether a customer takes generation service from a CCA or from PG&E. The PCIA is a charge that 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 (following a customer's departure from PG&E to CCA service).

The Study set the initial PCIA at the relatively high 2016 level, around 2¢/kWh, and stated that "they remained relatively flat throughout the forecast period."(p. 60) As the PCIA is notoriously difficult to forecast, and its current level is very high relatively to prior years, this assumption is reasonable to conservative. Note that the PCIA is further addressed in the Sensitivity Analysis and Risk sections.

Sensitivity Analyses

The Study explored the sensitivity of the results of its analysis to six major areas of uncertainty. As detailed below, MRW finds that the areas explored and range of the inputs encompass the reasonable expectations of the extremes that might occur in the values. Of course, unexpected events can occur that would result in inputs outside of the ranges presented here.

The Study presents the results of this analysis as a 10-year levelized cost of power (CCA and PG&E). While this provides a good snapshot of the gross impacts of different assumptions, the temporal aspect is lost. In other words, the levelized results do not say if the different assumption set makes CCA more costly in the first two years, less costly in the following eight years (such that the ten-year levelized cost is lower for the CCA than for PG&E.). Or perhaps the other way around, where the CCA costs are lower in the near term and greater in the longer-term.

MRW therefore recommends that PEA identify any sensitivity cases where the PG&E and CCA rate lines "cross," present those results, discuss the likelihood of that case coming to fruition, and describe how the CCA might address that risk.

Variables Considered

Natural Gas: Sensitivity to changes in natural gas and power prices were tested by varying the base case assumptions to create high and low cases. The high case reflects a 50% increase in this input relative to the base case and the low case reflects a 25% decrease relative to the base case. MRW finds that this range reasonably encompasses the likely natural gas price trajectory.

Renewables: The cost of renewables to PCE was increased and decreased by 25%. As this sensitivity was to the difference PCE would pay for renewables relative to PG&E, this range is reasonable.

Carbon-free: In consideration of the potential for increased CCA demand for low carbon content energy and the generally fixed supply of the large hydro-electric generation resource base available to California consumers, the Study explored the impact of increasing the carbon-free energy cost premium scenario by 300% (relative to the base case assumption), from about $3/MWh to $12/MWh. MRW finds this range to be reasonable.

PG&E Rate: PEA changed the PG&E generation rate escalation from 2.5% in base case to 5% for a high case and 1.5% for a low. This was a simple change to the escalation rate, without any underlying modeling assumptions. In particular, this case could use a year-by-year presentation. The better question answered in these scenarios is when the PG&E rate became consistently lower than the CCA cases. This cannot be answered with the results presented on a levelized basis.

Surcharges: The base case PCIA projections begin with the higher 2016 PCIA charges reported by PG&E and remain relatively flat over the forecast period. High and low cases were run at plus or minus 50% off of the base case. The PCIA is notoriously difficult to model, as it is very sensitive to the inputs feeding into the underlying equations. As the 2016 PCIA is particularly high relative to recent PCIA values, using it as the default and exploring even higher PCIAs is reasonable to very conservative.

Opt-Outs: PEA tested the sensitivity of ratepayer costs to customer participation in the CCA in Scenarios 1 and 2 by varying the opt-out rate from 25% in the high case to 5% in the low case. For Scenario 3, the high case was set to 35% for residential and small commercial customers and 60% for all other customer groups, while the low case was set to 15% for residential and small commercial and 40% for the other customer groups. MRW finds these opt-out rates to be reasonable.

Sensitivity Results

The Study presents the results of its sensitivity cases in two ways. First, it shows in Figure 25 (repeated here as Figure 5) the levelized rate for PG&E and each of the three CCA Scenarios. The triangle for each Scenario shows the base case value, with wings showing the range from the sensitivity cases. While overall this is a helpful figure, it may be a bit misleading: one can infer that because the lower-cost wings of the PG&E bundle case significantly overlap with the results of (for example) Scenario 2, that there is a large probability that the PG&E bundled rate will be lower than the CCA rate. This is not the case. The circumstances that results in the bottom of the PG&E wing do not likely correspond to the circumstances of the higher wing in for CCA. If (for example) power prices are high, they are for both the CCA and PG&E; PG&E won't experience low market prices while the CCA has high market prices. The results of the tables provide a more indicative presentation of the sensitivity analysis results.

Figure 5. Sensitivity Analysis Range of Levelized Electric Rates (Study Figure 25)

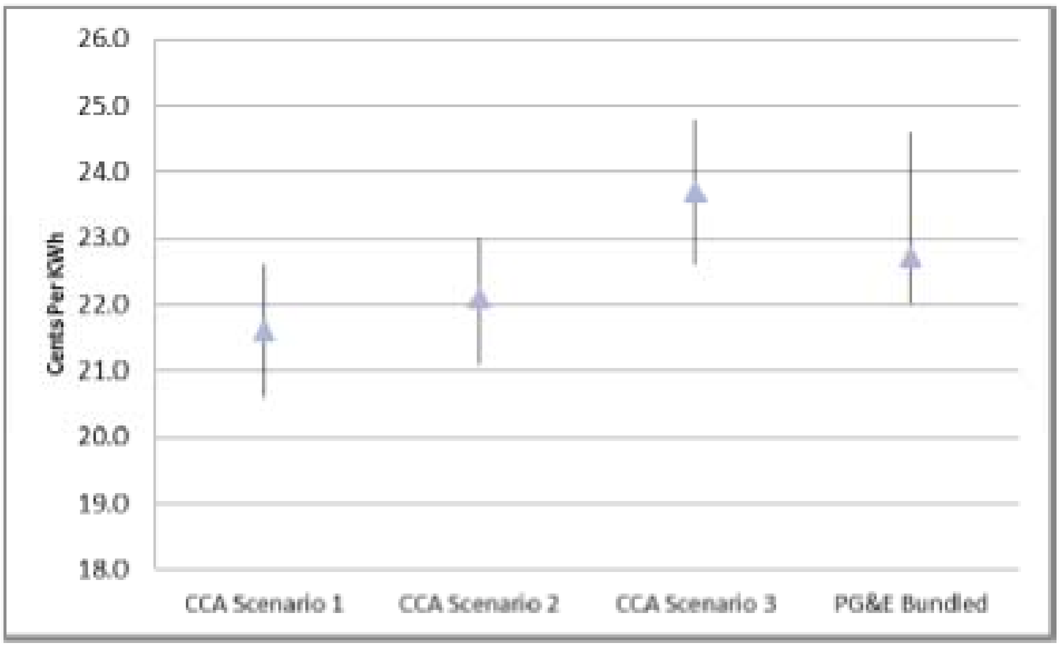


Table 2 below repeats the unnumbered table on page 61 of the Study, with some additional information. CCA scenarios that have lower levelized cost than the PG&E bundled rate are in green; CCA scenarios that have higher levelized cost than the PG&E bundled rate are in red, while ties are in yellow. As the table shows, the only times in which the PG&E bundled rate is less than the CCA Scenarios 1 and 2 are when PG&E independently has low rates or a high PCIA. And while either events is quite plausible—and in fact likely to occur—in isolated years, neither are likely to persist over multiple years.

Given that high PCIAs correlate to low gas prices (and vice versa), MRW created a new sensitivity cases (last 2 columns in Table 2) where we averaged the high gas/power case and the low PCIA case and the low gas/power case and the high PCIA case. As shown in the table, both of these cases show that the CCA scenarios offer lower average costs than the PG&E bundled rates.

Table 3 is analogous to Table 2, except with CCA Scenario 3. Here, as expected, in most cases the CCA scenario has higher rates than PG&E. The exceptions to this are when the CCA can acquire renewables that are prices 25% lower than assumed in the base case, PG&E experiences high rates (independent of any common market influences), and with a low PCIA. When the High Gas/Low PCIA scenarios were averaged, unlike with the other two CCA scenarios, the CCA Scenario 3 rate remains higher than the PG&E rate.

The rate increases relative to the Base Case seen in the High Gas/Power Case are puzzling. For all three scenarios, including the 100% renewable scenario, the CCA rates increased more than the PG&E Bundled rates. For example, the CCA Scenario 3 High Gas/Power rate is 0.7¢/kWh higher than the Base Case rate, while the PG&E Bundled (S3) rate is only 0.6¢/kWh higher than its Base case value. This would indicate that the 100% renewable portfolio assumed for the CCA Scenario 3 is more sensitive to natural gas and market power prices than PG&E's rate, in spite of the fact it contains minimal if no market power.

A possible explanation for this counterintuitive result is the way in which PEA modeled market renewables as an adder to the market power prices. Thus, as market power increased, so too did market renewable power, on a cent-for-cent basis.

Even though the vast majority of the sensitivity cases show that the CCA could be cost-competitive, it is likely that in an isolated year or two that PG&E's rates will be less than the PCE's average cost of service. In large part this is because of how utility rates are set in California. The California Public Utilities Commission (CPUC) allows PG&E to collect a certain amount of money each year. In each year, the amounts from the prior year are "trued up" so that PG&E collects the full cost of providing energy to its customers.[2] In some years, there can be a significant "over collection," whereby literally hundreds of millions of dollars of revenue collected for generation must be refunded to bundled customers. This refund depresses the PG&E's generation rate, quite plausibly below that of the CCA. As discussed in the risk section, this likelihood must be accounted for.

[2] Subject to a CPUC reasonableness review.

Table 2. Sensitvity Analysis: Scenarios 1 and 2 Leveized Ratpayer Costs (¢/kWh)

	Base Case	High Gas/ Power	Low Gas/ Power	High Renewable Costs	Low Renewable Costs	High PG&E Rates	Low PG&E Rates	High PCIA	Low PCIA	High Opt Out	Low Opt Out	High Carbon Free Cost	High Gas + low PCIA	Low Gas + High PCIA
CCA Scenario 1	21.6	22.5	21.1	22.1	21.1	21.6	21.6	22.6	20.6	21.7	21.5	21.6	21.55	21.85
CCA Scenario 2	22.1	23.0	21.6	22.7	21.4	22.1	22.1	23.0	21.1	22.1	22.0	22.3	22.5	22.3
PG&E Bundled	22.7	23.3	22.3	22.7	22.7	24.1	22.0	22.7	22.7	22.7	22.7	22.7	22.65	22.5

Table 3. Sensitvity Analysis: Scenario 3 Leveized Ratpayer Costs (¢/kWh)

	Base Case	High Gas/ Power	Low Gas/ Power	High Renewable Costs	Low Renewable Costs	High PG&E Rates	Low PG&E Rates	High PCIA	Low PCIA	High Opt Out	Low Opt Out	High Carbon Free Cost	High Gas + low PCIA	Low Gas + High PCIA
CCA Scenario 3	23.7	24.4	23.4	24.8	22.6	23.7	23.7	24.7	22.7	24.0	23.6	23.7	23.55	24.05
PG&E Bundled	23.2	23.8	22.8	23.2	23.2	24.6	22.5	23.2	23.2	23.3	23.1	23.2	23.5	23.0

Jobs and Economic Analysis

To quantify the economic impacts associated with new renewable generation projects that were incorporated in each of the three energy supply scenarios, the Study utilized the National Renewable Energy Laboratory's Jobs & Economic Development Impact (JEDI) models. The JEDI models are publicly available, spreadsheet-based tools that were specifically designed to "estimate the economic impacts of constructing and operating power plants, fuel production facilities, and other projects at the local (usually state) level. This is an appropriate tool for estimating the rough order of magnitude economic impacts of a CCA's supply portfolio.

The Study presented results for three scenarios for job creation, earnings and economic output. These are summarized in a table on page 29 of the Technical Study.

Overall, MRW commends PEA in explaining the impacts. However, it should be noted that the "jobs" during the construction period are better understood by laymen as job-years. Since the development and construction will occur over roughly 8 years (2018-2025), the results show an average of about 900 full-time jobs in place during the 8-year construction period. Of these, about 190 will be construction, while the remaining would be in other industries and induced in the greater economy.

The Study also presents local economic development estimates for San Mateo County. These come from the implementation of the FIT program and the CCA's staff. JEDI suggests that the FIT program may generate 370 job-years during construction (45 FTE for 8 years) and 6 FTE workers for ongoing maintenance.

MRW found that the Study can be misleading when characterizing these economic impacts. For example:

> During ongoing operation of the renewable generators, it is projected that **as many as** 130 new jobs would be created with a total annual economic impact ranging from $10 to $20 million. It is anticipated that these jobs would remain effective as long as the generating facilities remain operational, **resulting in significant, lasting impacts to San Mateo County's local economy**. (p. 30. Emphasis added.)

First, "as many as" is the top of a range of estimates, and thus not indicative. Second, 300 of the 330 megawatts of renewable capacity are to be constructed outside of San Mateo Country. Thus to suggest that the operation of these remote generators will have "significant, lasting impacts to San Mateo County's local economy" is misleading, if not disingenuous.

Similarly the report states:

> As reflected in the previous table, the indicative long-term contract supply portfolio, which is assumed to exist in each of the CCA program's three planning scenarios, would result in **significant** economic benefits throughout the state and, **potentially, within the San Mateo Communities**. (p. 29. Emphasis added.)

While these impacts are positive, to characterize them as "significant" in the context of the California economy is an overstatement. There are 19 million workers in California and an annual gross state product of over $2.3 trillion. While 130 jobs in some locations, particularly the Central Valley where unemployment is high, would be a real boost to a local economy, it is not significant when considered state-wide. Also, given the locations of the generators, to suggest that they would create significant benefits to San Mateo communities is misleading. Benefits, yes, but modest ones.

MRW concurs with the Study that PCE would have little to no impact on the PG&E workforce. PG&E would still need to service and maintain its distribution system in the county and provide most of the same general service functions (i.e., billing and collections).

Risk Analysis

PCE faces numerous risks as a CCA. The Study identified many of these risks, assessed the likelihood of occurrence, the magnitude of the risk, and impact of negative consequences resulting from the risk. The Study also presented its assessment of the ways that PCE could mitigate the risk and/or adapt its operations going forward to account for the risk. MRW has examined the Study's risk assessment (both that presented in the report as well as the "Risk Assessment Matrix") and overall find that PEA has done an excellent job at identifying these risks and suggesting ways to mitigate them. Still, MRW has several comments related to the types of risk and the manner in which PCE might hedge the risks.

Start-Up Risks

During the formation of PCE, it must expend funds for studies, legal opinions, regulatory activities, and other activities necessary to prepare for launch. While these costs are small relative to the expected revenues of PCE at the expected full build-out, PCE effectively must borrow funds for these activities, with the expectation that they would be repaid out of operating income. However, if opt-out rates are higher than expected or participation by cities, towns, and/or the County is lower than expected, then PCE will face challenges in repaying the County, which has funded the start-up costs (estimated by PEA to be $1.5 million).

The Study correctly identifies these risks as having a low likelihood but that if such a future were to unfold, it would have a low-to-medium impact on PCE. If opt-out rates are higher than expected in the near-term, PCE can always expand the initial enrollment tranche. If there are lower levels of participation in the JPA than expected, PCE can always either delay start-up until conditions warrant restart, look to join other CCAs, or terminate the project. Under the second or third option, it is unlikely that the County would recover its start-up costs.

Competitiveness Risks

As a competitor to PG&E, PCE must be mindful of the costs that it charges customers relative to PG&E. PCE also should be mindful of how it differentiates its services from PG&E. If PCE's costs exceed those of PG&E, there is an incentive for customers to either opt out during the initial opt-out period or to return to bundled service from PG&E. As discussed above, opt outs prior to or during program launch can place PCE at risk of failure to recover its start-up costs. If customers depart over time, that can put PCE in the position of having stranded costs.[3]

PEA has done a good job of identifying the competitiveness risks facing PCE and suggesting how PCE should mitigate or adapt to address changing market conditions. MRW has some additional thoughts regarding mitigation or adaption strategies:

PCE Rates Exceeding PG&E's

There is a high likelihood that PCE's rates could exceed PG&E's for short periods. The Study recommends utilizing short-term markets for a portion of power purchases so that PCE rates trend with PG&E's. MRW agrees with this suggestion with some additional clarification. In order to have PCE's rates trend with PG&E's generation rate, it will be necessary to have PCE's portfolio match PG&E's portfolio in terms of fuel and duration of commitments. This could cause problems in the near-term if PCE is attempting to have a portfolio that has lower GHG emissions than PG&E. In addition, it is important to note that PG&E's generation rates are trued up each year through balancing accounts. Under- or over-collection of generation costs by PG&E can result in significant balances in PG&E's balancing account, which PCE would likely not be able to replicate. As a result, MRW believes that PCE should consider establishing a significant reserve fund to mitigate times where PG&E has significantly over-collected and has generation rates that are lower than its going-forward cost of service. A reserve fund would also allow PCE to mitigate to a certain extent significant swings in exit fees that occur when gas prices change.

Market Volatility

MRW agrees market volatility is a concern for PCE and its impact is somewhat important. The Study suggests that one way to mitigate against power market volatility is to enter into multi-year purchase agreements. This is generally true. However, it is important to note that while longer-term agreements reduce volatility, they do so at a cost, just as insurance can reduce the risk of catastrophic accidents but will cost more if such an accident does not occur. Over-insuring could put PCE in a position of being unable to remain competitive with PG&E in times of declining market prices. It is the case that gas prices are very low and, as a result, market prices are low as well. Thus, MRW believes there is likely greater risk of increases in market prices and those risks would be mitigated by longer-term agreements. MRW also agrees with PCE's recommendation regarding establishing a rate stabilization reserve fund (see above) but notes that such a fund comes at a cost and it will be important to balance the insurance value of a reserve fund against the near-term rate impacts of establishing the fund.

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[3] In the near-term, stranded costs are likely not a concern. However, in the long-term, if PCE develops its own generation assets (or buys portions of generation assets), customers returning to PG&E could result in increased costs to remaining PCE customers. PCE should consider whether to establish exit fees and communicate that intention during program formation.

Supply Shortages

At the present time, it is relatively easy to procure renewable and GHG-free resources. As such, there is a low likelihood of supply shortages in the near- and intermediate term. However, as California's load-serving entities start to procure resources to meet the 50% RPS requirements and as additional CCAs are formed and attempt to provide lower GHG levels than the local IOU, it may become more difficult to procure resources at competitive prices. The Study's recommendations regarding making multi-year forward purchases are sound.

Regulatory and Legislative Issues

MRW generally agrees with the Study's view that it is important for PCE to actively monitor and, if necessary, intervene in the regulatory and/or legislative processes to defend its interests. While PG&E has taken a lower profile position regarding CCAs, it will continue to defend and attempt to disadvantage CCAs at the CPUC and the Legislature. This is a real threat to PCE and could have a significant impact.

Technology Risks

MRW agrees with the Study that the likelihood of this risk affecting PCE is low. PG&E enters into long-term renewable contracts. PCE will likely not enter into contracts with longer duration than PG&E's and PG&E's renewable portfolio has numerous high-cost contracts, primarily because PG&E aggressively procured renewables to meet its 33% RPS requirements. MRW also agrees that having a blend of generation assets with different terms is important. It is especially prudent to tend toward shorter-term commitments during times when prices are falling.

Business and Operational Risks

PCE faces risks related to its own operations. These include maintaining/establishing credit, maintaining liquidity, and ensuring that PCE's portfolio of suppliers performs as expected (and if a supplier does not, that supplier can pay costs to cover). While these risks generally have low probabilities of occurrence, they can have very significant consequences.

CCA Bonding Requirement

While mentioned in the Study (p. 44) and generally lumped into "regulatory risk," the risks of changes to the CCA Financial Security Requirement should be remembered. Pursuant to CPUC Decision 05-12-041, a new CCA must provide evidence of insurance or bond that will cover such costs as potential re-entry fees, i.e., 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 modest administrative costs.

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 PCE's 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 PCE 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.

Nonetheless, MRW believes that this risk should be explicitly included in the "PCE Risk and Mitigation Matrix" with a Likelihood of "Low," an Impact of "Medium" and a Level of Risk/Impact of "Medium."

Cash Flow Analysis

The PEA report included a 10-year pro forma tables for each of the three scenarios. Additionally, a monthly cash flow model was provided for scenario 1 for the startup period and the first 5 years of PCE operation. The models included:

a) Sources of funds: sales revenue, advances from the County and startup bank financing;
b) Expenditures: power supply, staffing & other operations, startup financial; and
c) Reserve fund accrual.

The average cost of power appearing in the pro forma was consistent with the cost of power in the report. Once in full operation, PCE would be taking in and expending about $20 million per month.

Key assumptions in the cash flow model are the initial bank financing of $6.5 million and how it is paid off; how the $1.5 million by the County for CCA formation is paid off, and the accrual of a reserve fund. The amount for the back financing is sufficient to operate the first months of operation while maintaining at least a month's cash reserve on hand. While perhaps tight, this is reasonable. The bank financing is paid off over 60 months at 3% interest.[4] Monies provided by the County during the pre-startup phase is also repaid over 5 years ($25,000 per month) with no interest. MRW finds the bank financing and repayment to be reasonable. While getting bank financing is a major hurdle for an entity with no credit history, the operational CCAs have succeeded in acquiring it, and PCE could not move forward without it.

The cash flow model shows contributions to “other deposits accounts” of $2.46 million per year. MRW assumes these deposits are to a reserve fund.

There are some differences between the cash flow model and the pro forma tables provided in the October 16 Report. First, the cash flow model shows power costs about 4-5% higher than the pro forma. Second, the “other expenses” in the cash flow mode are $1-1.3 million greater than what is shown in the pro forma. Third, the pro forma shows a much larger startup financing debt service, $4.9 million per year versus $1.05 million in the cash flow model. Clearly, two different amounts are assumed.

MRW suspects that one simply reflects more recent assumptions than the other, but nonetheless recommends that they be reconciled.

Conclusions

Overall, MRW finds that the Study was thorough and professionally performed. We found no “fatal flaws” or major assumptions that require revision. As noted here, there are a few areas that may benefit from clarification, expansion or revision, but overall the Study is sound.

Even though the Study finds that the CCA would be cost-competitive under a wide range of assumptions over the 10-year period, given ratemaking in California, it is likely that in an isolated year, PG&E’s rates will be less than the PCE’s average cost of service. This can be addressed both through sufficient rate stabilization reserves and good communications with its customers.

[4] Note that the cash flow model inadvertently showed the payments stopping 8 months early.