Memorandum

To: City of San Diego

From: Mark Fulmer and David Howarth

Subject: Peer Review of "Community Choice Aggregate Feasibility Study" Draft Report dated April 6, 2017

Date: February 22, 2018

In late 2016, the City of San Diego (the City) commissioned a study to understand the feasibility of using a Community Choice Aggregation (CCA) program to assist in meeting its goal of achieving 100% renewable energy city-wide by 2035. The CCA Feasibility Study was requested to provide an in-depth technical, economic, and financial analyses of the potential costs, benefits, and risks of CCA for the City under a variety of future outcomes, or scenarios. The study is intended to provide policy makers, stakeholders, and electricity consumers information for assessing the feasibility of a CCA program for the City.

On April 14, 2017, the City provided MRW & Associates, LLC (MRW) a draft report entitled "Community Choice Aggregate Feasibility Study" dated April 6, 2017 (the Study), and requested MRW to provide a professional peer review of the Study. This memorandum provides MRW's review. Beyond the Summary of Conclusions, it is organized around 15 questions concerning the Study to which the City asked MRW to respond.

Summary of Conclusions

Overall, the Study is detailed and comprehensive. Its assessment of loads and load forecast are thorough and reasonable, and it provides an in-depth look into potential CCA operations. The Study provides a reasonable estimate of an expected range of CCA power procurement costs, including a conservative estimate of renewable energy costs. Likewise, the greenhouse gas emissions estimates for both the CCA and SDG&E are reasonable.

The Study used the current best practice tools for estimating jobs and employment stimulation from the CCA. Consistent with other CCA studies, the Study identified job creation from economic stimulus resulting from reduced electricity bills and from local project development. However, it should be noted that in the context of the economies of the City and region, the job creation should be characterized as modest and not "significant."

Our greatest concern is that the forecast of SDG&E rates is disconnected from the forecast of CCA rates. The SDG&E rates against which the CCA rates are compared are simply an extrapolation of current rates. It does not account for SDG&E's actual supply portfolio, SDG&E's status with respect to State renewable power content mandates, fuel price trends, or any other underlying fundamentals. In particular, there is no explicit connection between the SDG&E generation rate and the CCA generation cost, even though the two entities would be purchasing from the same wholesale market and vying for the same incremental renewable generation sources.

Our second, related concern is that the Study applied the commodity cost adjustment rate of change—i.e., the projected changes to the generation (Schedule EECC) rate—to the total SDG&E rate. This implies that SDG&E's delivery rate—transmission and distribution—will escalate the same as its generation rate. These two rate elements are driven by very different cost structures: the generation rate is driven by power-related costs while the delivery rates are driven by transmission and distribution investments and costs. This assumed escalation rate for SDG&E delivery charges would not be material if the same delivery rate was used for both the SDG&E rate and the CCA rate. However, it is not clear from the Study that a common delivery rate was used when comparing SDG&E and CCA rates. The CCA rates presented in the Study are flat, i.e., the 2023-2026 rates are held at the 2022 "test year" level. Implicit in this is one of two assumptions: (1) the CCA's generation rate plus PCIA is decreasing so as to exactly offset the escalating SDG&E delivery rate, or (2) the analysis erroneously held the SDG&E delivery rate constant from 2022-2026. If the former is true, then it should be explicitly explained and demonstrated. If the latter is true, then the error should be corrected.

Our third concern is that the Study assumes overly conservative assumptions about contributions to reserve funds. The pro forma analysis appears to assume that approximately $97 million (12% of total expenses) is contributed ***each year***, rather than setting a target (e.g., 15% of annual expenses), taking 3 to 5 years to achieve the fund, and then eliminate further contributions until replenishment is needed. This inflates the cost of service of the CCA.

Lastly, we recommend that sensitivity cases used to explore the impact of lower SDG&E rates and higher exit fees consider a wider range of potential values.

Responses to Questions

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

Overall, the forecast of CCA energy requirements is reasonable. The Study appropriately notes "For this Study, the amount of energy that CCA customers will use is based on historical consumption data obtained from SDG&E as well as consideration of other forward-looking variables" and "The load forecasting methodology for this Study includes three activities: analysis of historic customer data, forecasting future requirements, and incorporating adjustments for anticipated changes." Overall, the forecast shows minimal to no net growth in load; that is, natural load growth from increased economic activity is offset by efficiency and behind-the-meter customer generation (e.g., rooftop solar). This is consistent with the official projections being made by the California Energy Commission.

Direct Access: Since DA customers are not likely to join a CCA due to an existing contract with an ESP, for purposes of this Study DA customers have been excluded from the load forecast.

Opt-out 20% base assumption. The Study assumes that 20% of the eligible customers will opt-out of the CCA and remain on bundle SDG&E service. In supporting this assumption, the Study points to opt-out rates in other CCAs, which are typically in the 15% range. These data appear to be too high—that is, opt-outs experienced Peninsula Clean Energy were in the single digits. Even so, the Study includes sensitives to opt-outs that indicate that the results are not particularly sensitive to the opt-out rate. This is consistent with MRW's experience. Thus, even if the 20% assumption overstates the opt-out rate, it does not change the Study's conclusions.

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

The Study provides a comprehensive review of current power market conditions, including a qualitative summary of power procurement considerations (e.g., renewable portfolio standard (RPS), resource adequacy and storage) as well as a quantitative analysis of recent historical pricing for renewable energy, natural gas generation and California Independent System Operator (CAISO) day-ahead and real-time wholesale electricity markets. The study presents data on current expectations regarding the relative levelized cost of energy for different generation technologies and recent declines in solar photovoltaic (PV) costs. The Study also presents data showing trends in utility RPS compliance costs, as reported annually to the California legislature (i.e., the Padilla report) and in the Biennial RPS reports.

Renewable Energy Procurement. To forecast CCA renewable energy procurement costs, the Study consultants developed a best-fit logarithmic curve using average utility RPS compliance costs depicted in Figure 41 of the draft Study. The resulting RPS price forecast is likely a conservative estimate of CCA renewable energy procurement costs. This is because the data used to forecast RPS price trends do not necessarily reflect the market in which the CCA will operate since the data reflect utility procurement costs for energy delivered during a particular year. The renewable energy portfolios of utilities include contracts struck over a period of time during which technology costs have been rapidly decreasing. As a result, the decline in costs incurred by the utilities for renewable energy deliveries has lagged behind the decline in costs for new (incremental) resources. This point is referred to in footnote 60 of the draft Study, which quotes an explanation by CPUC staff. As a result, the CCA will be entering into new contracts at current and future market prices that will likely be lower than the average utility RPS compliance cost as reflected in Figure 41. The Monte Carlo Simulation Model (MCSM) used for the Study is useful for reflecting uncertainty in forecasts of procurement costs, by providing a statistically characterized range around this base forecast. The report does not provide information concerning the way in which RPS price uncertainty was characterized in the MCSM, so it is not possible to review the reasonableness of these assumptions.

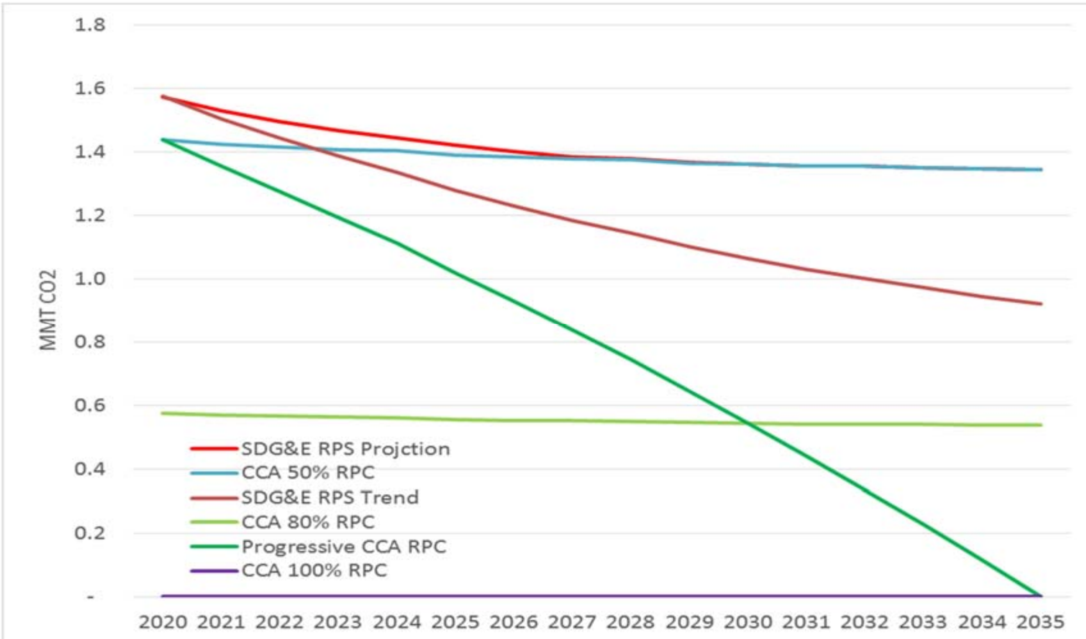
Natural Gas Generation. In the case of natural gas generation prices, the Study fit a curve to 2002-2016 CAISO market implied prices to forecast prices for the period through 2035 (Figure 45). Based on this analysis, natural gas generation costs are forecast to decrease by 34% from $41/MWh in 2020 to $27/MWh in 2035. This trend analysis may be underestimating natural gas generation costs over the long term by not differentiating between trends in market heat rates and natural gas prices, which may be driven by different market dynamics not captured by the trend analysis. Natural gas prices are relatively low at present. In its 2017 Annual Energy Outlook, the Energy Information Administration forecasts natural gas prices for electricity generation in the Pacific region to increase by an average of 3% per year between 2020 and 2035. Based on this forecast of natural gas prices, the forecast of natural gas generation costs used in the Study suggests market heat rates (the implied rate of conversion of natural gas energy to electricity, in Btu/kWh) will decrease by almost 60%. While there may be downward pressure on market heat rates as additional renewable energy sources are brought on line, a 60% reduction in market heat rate is likely not sustainable since it would be difficult for natural gas generators to recover costs. The Study would likely benefit from a review of this assumption and the associated discussion of the forecast. As with the RPS cost forecast, additional information on how natural gas price uncertainty was reflected in the MCSM would be needed to make an assessment of reasonableness.

Other Cost Components. Following the cost of RPS procurement and natural gas generation, resource adequacy (RA) represents the remaining significant component of CCA procurement costs. The Study provides a reasonable forecast of RA costs. The remaining components, including CAISO day-ahead and real-time markets and storage procurement represent a small fraction of total costs, just 3% in the 50% RPS case. The forecasts used in the Study for these cost components appear reasonable.

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

The Study's projections of CCA greenhouse gas emissions are generally reasonable. The figure below replicates Figure 64 in the Study. Note that the "SDG&E RPS Projection" line (red) converges with the CCA 50% RPC line (light blue) by 2030. This reflects the fact that in 2030 SDG&E would be meeting the 50% RPS requirement in 2030, the same renewable content as the CCA.

The "SDG&E RPS Trend" line in the figure (reddish-brown) is interesting and provides a conservative benchmark against which the CCA's GHG emissions can be compared. However, it should not be used to provide the basis for a GHG analyses.



Consistent with other CCA analyses conducted or peer reviewed by MRW, the Study illustrates that if a CCA wishes to reduce GHG emissions relative to remaining with the incumbent utility, while maintaining competitive rates, it would need to explicitly contract for non-RPS complying, GHG-free power: that generated by large hydroelectric or nuclear facilities.

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

To arrive at 2020 SDG&E rates, the Study took current rates and escalated them at an annual rate of 3% to 2020. (p. 90) As SDG&E does not publicly release rate forecasts, the Study relied upon the public 20-year forecast of SDG&E's EcoChoice Rate.[1] "SDG&E rate escalation was based on the commodity cost adjustment rate of change in this schedule applied to the projected 2020 rates." (p. 90) For the PCIA, the Study relied upon the actual March 2017 PCIA escalated using PCIA escalation rates from the EcoChoice rate forecast.

MRW has some concerns with the approach. The first concern is with the source of the SDG&E forecast. The EcoChoice Rate forecast arises from CPUC Decision 16-05-006. This decision addressed the three major California IOUs' "Enhanced Community Renewables" option, which allows SDG&E and the other two IOUs' customers to purchase renewable energy from specific community-based renewal generation projects (p2). This is generically known as "community solar." In addition, the Decision adopted a ***forecasting methodology*** to establish a 20-year estimate of bill credits and charges for the Green Tariff Shared Renewables. (p. 2) The Order stated (p. 24):

[1] Shared Renewables Green Tariff Schedule (GT); this rate may increase in July but as of March 2017, SDG&E has not officially released any information.

> As suggested by TURN, we will rely on the rolling five-year average from the trend analysis to set the escalator for the Class Average **Generation** rate. In addition, it appears that there is data available for trend purposes for the Resource Adequacy charges, Grid Management (CAISO) charges, Western Renewable Energy Generation Information System charges, and the Power Charge Indifference Adjustment (PCIA).
>
> In each of these cases, the utilities should utilize the 2016 price as the starting point for the 20 year forecasts and escalate based on the five-year rolling average. [emphasis added]

In other words, the generation rate escalators in the EcoChoice Tariff's forecast is a simply 5-year rolling average.

Our first concern is that this is too crude a forecast methodology: it is simply SDG&E's 2017 generation rate, increased based on the past 5-year trend. It does not account for SDG&E's actual supply portfolio, SDG&E's status with respect to its RPS mandates, fuel price trends, or any other underlying fundamentals. In particular, there is no connection to the CCA generation cost, even though the two entities would be purchasing from the same wholesale market and vying for the same incremental renewable generation sources. We note that a disclaimer provided with the forecast states: "…the 20-year forecasts shown here are not necessarily representative of SDG&E-specific forecasts of rate components."

Our second, related concern is that the Study applied the commodity cost adjustment rate of change—i.e., the projected changes to the generation (Schedule EECC) rate to the total SDG&E rate. This implies that SDG&E's delivery rate—transmission and distribution—will escalate the same as its generation rate. These two rate elements are driven by very different cost structures: the generation rate is driven by the PPAs, utility-owned generation and underlying power market costs, while the delivery rates are driven by labor costs and the rate of (and rate of return on) utility investment in capital projects for transmission and distribution.

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

Uncertainty in forecasts of energy prices, whether it's for renewable energy, wholesale energy or natural gas is unavoidable and no forecast will be "right." However, confidence in an assessment of the feasibility of a CCA providing service at costs comparable to that of the utility would be improved by ensuring to the extent possible that the underlying market forecasts are used consistently to estimate each entity's costs. While consistency is important, the analysis should also recognize that, in some cases, the utility and the CCA may be starting from a different point and therefore face different costs (e.g., average vs. incremental renewable energy contract costs). That said, for the purposes of a feasibility study, there is value in performing sensitivity analyses that attempt to bound the uncertainty in the underlying forecasts and provide comparisons over a range of market conditions. To some extent, the sensitivity cases with high or low SDG&E rates provide such a bounding. The Monte Carlo simulation modeling approach used in the study also provides an opportunity to reflect uncertainty in CCA costs. It does not appear, however, that the rate comparisons in the Study report utilize the MCSM results presented in Appendix E. It would be helpful to incorporate these results into the rate comparison.

Our concerns regarding escalation of the SDG&E delivery rate raised in response to Question 4 would not be material if the same delivery rate is used for both the SDG&E rate and the CCA rate. However, it is not clear from the Study report that a common delivery rate was used in the comparison of SDG&E and CCA costs. As noted above, the SDG&E rate forecast was based on the escalation of both the EECC and delivery rates. The CCA rate in Table 6 is assumed to be flat, i.e., the 2023-2026 rates are held at the 2022 "test year" level. Implicit in this is one of two assumptions: (1) the CCA's generation rate plus PCIA is decreasing so as to exactly offset the escalating SDG&E delivery rate, or (2) the analysis erroneously held the SDG&E delivery rate constant from 2022-2026. If the former is true, then it should be explicitly explained and demonstrated. If the latter is true, then the error should be corrected.

What would be helpful would be a comparison table that showed, either on a class basis or on a system average basis the following (in $/kWh):

YEAR	SDG&E			CCA					
	a	b	c = a+b	d = a	e	f	g	h = d+e+f+g	i=(h-a)/a
	Delivery Rate	Gen. rate (EECC)	Total Rate	Delivery Rate	Ave. Power Cost	Other Costs	PCIA	Total Rate	Pct. difference
2022									
2023									
2024									
2025									
2026									
…									

6. Do the pro forma analyses consider all pertinent factors in projecting CCA's operating results?

Yes, the pro forma analysis considers all pertinent factors. However please see responses to other questions for MRW's opinion on the specific treatment of some of the factors.

7. Do the pro forma analyses include reasonable cost-of-service variables?

Power Costs: As discussed above, there is a great deal of uncertainty in forecasts of power costs. The base forecast of RPS procurement costs is likely conservative, while the forecasted costs of natural gas generation may be lower than expected over the forecast period. To the extent that the pro forma analyses include MCSM results the pro forma results may reasonably reflect the expected range of power costs. It is difficult to assess the reasonableness of the MCSM analyses with information presented in the Report.

Other Operating Costs. Operating costs consist of all costs directly associated with provision of the business services and activities of the CCA—namely procuring and providing power to customers. The Study thoroughly presented the operating costs of a hypothetical CCA. Nonetheless, the assumed staff costs may be overstated. The 44 FTE staff used in the study is excessive relative to existing CCAs.

Included in operating costs is the Power Cost Indifference Amount (PCIA). The PCIA is the state-mandated fee that SDG&E imposes on all departed load (including CCA customers) to ensure that the rates of utility customers who do not—or cannot—choose CCA service do not increase because of CCA. Like with the SDG&E bundled rates, the Study relies upon a forecast of the PCIA rate from the ESDG&E EcoChoice Rate forecast. Because the PCIA is difficult to accurately forecast, this assumption is not unreasonable, but as noted later, must be thoroughly explored in sensitivity analyses.

Non-Operating Costs. Non-operating costs include initial capital outlays for longer-lives assets required to get the CCA up and running as well as the associated debt issuance and annual debt service required to fund the CCA. Non-Operating Costs also include a contingency/rate stabilization fund. The Study thoroughly presented the non-operating costs of a hypothetical CCA.

Assumed reserves funding. Beyond working capital, CCAs typically develop a "rate stabilization reserve fund" which can be drawn upon in years' where the CCA might not otherwise be able to meet its rate targets. The Draft Study pro forma analysis appears to assume that approximately $97 million (14% of total expenses) is contributed ***each year***, rather than setting a target (e.g., 15% of annual expenses), taking 3 to 5 years to achieve the fund, and then eliminate further contributions until replenishment is needed. This inflates the cost of service of the CCA. While having an appropriate reserve fund is necessary, the modeling overstates the needed reserve contributions.

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

MRW sees the Study as a tool to assess whether a CCA can meet specific goals and remain financially viable. As such, conservative (i.e., higher) operating costs should be used. There are no systematic cost reductions that MRW can suggests at this stage. Of course, if the CCA moves forward, it should consider various standard cost reduction alternatives, such as staff optimization and outsourcing tasks that are outside the core skill sets of City staff.

9. Does the Study present an adequate analysis of potential economic benefits and challenges of various supply scenarios?

The Study only examined the jobs and economic impacts of the Base Case. As discussed below, given the nominal impacts and the inherent uncertainties of macroeconomic and jobs analyses, this is adequate.

10. Does the Study present a reasonable assessment of job creation, both total jobs created and local jobs created?

The Study considered the employment impacts of two separate mechanisms: those jobs created by the increased disposable income from lower electric bills and the jobs associated with local investment in renewable resources. By far the larger of the two impacts is that of bill savings; the Study projects approximately 550 jobs in 2022 associated with the $48 million in projected bill savings. The direct investment in local renewable (solar) resources is projected to generate around 60 jobs while projects are being constructed and 10 jobs for ongoing operations and maintenance of those solar resources. The Study does not consider job creation associated with ongoing CCA management/operations nor out-of-area jobs created by renewable project development.

The Study used the IMPLAN Group LLC's (IMPLAN's) Input-Output Multiplier Model (I/O Model to quantify the expected economic impacts arising from lower energy bills for CCA customers. IMPLAN is an industry-standard economic modeling software quantifying relationships (dependence) between industries in an economy, and is an appropriate tool to estimate the larger economic and employment impacts of bill savings.

The San Diego-Carlsbad Metropolitan Statistical Area region economy is $220 billion[2] with employment at 1.5 million. Thus, the impacts calculated -- $48 million savings and 500-600 jobs -- should be characterized as nominal at best and not "significant."

The Study assessed the potential economic development benefits associated with CCA building 10 MW of solar projects in the City using the Jobs & Economic Impact Development (JEDI) model developed by the National Renewable Energy Laboratory. First, it should be noted that the 10 MW of locally-sited solar is not explicitly included in the pro forma analyses, and must be seen as illustrative only.

The JEDI model is the most commonly used tool to estimate these kinds of impacts of renewable power project development, and is appropriate. The Study also acknowledged that the opportunity for larger-scale (i.e., not simple behind-the-meter rooftop) solar is limited within the City.

The estimated impacts depend on the number of jobs created and the salaries for each position. In addition, if the jobs are not sourced locally, but rely on workers from other areas of the country, state or region, the local direct impacts would diminish. The JEDI model uses "economic multipliers" to approximate impacts within the supply chain (e.g., manufacturing job creation). These multipliers are only estimates of potential effects and, perhaps more importantly, may not fully take into consideration that these effects may occur outside the local area. It is possible, for example, that the manufacturing jobs created as a result of power projects would be out of the local area or the U.S. entirely.

[2] https://www.bea.gov/iTable/iTable.cfm?reqid=70&step=1&isuri=1&acrdn=3#reqid=70&step=10&isuri=1&7003=200&7035=-1&7004=naics&7005=-1&7006=41740&7036=-1&7001=2200&7002=2&7090=70&7007=2015&7093=levels

Other impacts. The Study also notes that other CCA activities, such as rooftop solar promotion and energy efficiency programs would also generate employment. This is accurate. However, while these may generate direct jobs, if they place an upward pressure on rates (that is, their costs exceed the marginal cost of power), that would increase rates and result in less induced economic benefits from rate savings.

In a later section of the report, the Study notes:

> Launching the CCA will likely result in a reduction in workforce at SDG&E as fewer resources will be required to perform the functions that the CCA will begin providing to customers. Therefore, outsourcing customer service and power procurement functions to an ESP could have a net negative impact on employment in San Diego."(p. 145)

MRW doubts that this impact would materialize. First, even though the CCA will offset a significant amount of SDG&E's power procurement, SDG&E will continue to have manage its existing power contracts and develop incremental procurement. Thus, SDG&E's power procurement and management employment may shrink, it would do so only modestly. Second, customer services generally address issues that are not power procurement related, such as new accounts, address changes and outages. MRW would not expect any staffing level decreases because of CCA formation.

Conclusions on Economic Development Estimates. Overall, MRW agrees qualitatively with the Report that local projects would stimulate local economic activity. However, MRW has three general concerns with the quantitative economic development estimates. First, all macro-economic models have built-in uncertainties, and the resulting forecasts should be seen as being indicative of order-of-magnitude impacts rather than being precise. Second, the models are generally designed to look at larger geographic areas than a single city, even one as large as San Diego. When attempting to apply the economic models to a smaller area, uncertainty is greatly increased due to the impact of "spillover" into adjacent areas (i.e., workers on San Diego projects living and spending money in other cities).

Third, the JEDI model estimates the direct, indirect and induced effects associated with new power projects, but does not take into consideration that there could be a negative "ripple" effect associated with higher rates necessary to pay for these projects over time. In other words, if residents and businesses pay higher rates for local projects, they could spend less money in the local economy, which could have negative indirect and induced multiplier effects. While we would not expect that these negative indirect and induced effects would cancel out benefits of local projects, they were not acknowledged or included in the analysis.

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

The Study evaluated the CCA's ability to offer competitive rates in two ways. First, to assess the CCA's procurement costs, it applied the Monte Carlo analysis to its power costs. Second, the Study included eight additional analysis around its base scenario to "examine the impact of changes in key cost drivers to CCA operating performance and feasibility outcomes."(p. 36) It also considered three additional scenarios:

50% RPC in the base and no opt-ups to 100% RPC; 80% RPC in the base and no opt-ups to 100% RPC; and 100% RPC for the full supply portfolio. These sensitivities and scenarios are summarized in the table below.

Sensitivity Analyses and Scenarios

Sensitivity	Description	Assumption	Ave. CCA Base Rate Premium (Savings)*
-----	**Base**	**Base**	**-4.5%**
Sensitivity 1	High SDG&E Rates	6% increase in SDG&E rates as of 2020	-18.7%
Sensitivity 2	Low SDG&E Rates	2% decrease in SDG&E rates as of 2020	+2.1%
Sensitivity 3	High PCIA	10% increase in PCIA as of 2020	+6.8%
Sensitivity 4	Low PCIA	2.5% decrease in PCIA as of 2020	-6.6%
Sensitivity 5	High Opt Out	25% Opt Out Rate	-4.5%
Sensitivity 6	Low Opt Out	15% Opt Out Rate	-4.5%
Scenario 2	50% RPC Base	No opt-ups to 100% RPC	-4.5%
Scenario 3	80% RPS Base	No opt-ups to 100% RPC	+2.4%
Scenario 4	100% RPC Base	All customers at 100% RPC	+7.0%
*** Average of the 2022 through 2026 CCA Rate Premium/(CCA Savings) rows in Tables 33, 36-44**			

Two of the sensitivity scenarios explore "up-side" alternatives: Sensitivity 1 (High SDG&E Rates) and Sensitivity 3 (High PCIA). That is, these sensitivities reflect changes that benefit the CCA, and as such are of only passing interest. The two opt-out sensitivity scenarios (5 and 6) do not materially change the results. This is consistent with MRW's experience.

Two sensitivity scenarios explore detrimental impacts: Sensitivity 2 (Low SDG&E Rates) and Sensitivity 4 (Low PCIA). In both cases, the CCA would not be able to offer lower rates than SDG&E.

The Study's High SDG&E Rates sensitivity case assumes SDG&E rates would be 6% higher than the Base Scenario. Given that the delivery rates are the same for CCA and SDG&E customers, this means that the rate increase here would be due exclusively to increased SDG&E generation rates. Thus, the 2% decrease in SDG&E rates reflects roughly a 4% decrease in SDG&E generation rates. As noted earlier, given the fact that the SDG&E rate is not tied to any underlying fundamental power costs but a simple extrapolation, a greater sensitivity is warranted. MRW suggests a 6% decrease in SDG&E rates so as to reflect some symmetry with the more extreme Sensitivity 1 (High SDG&E rates).

The High PCIA case assumes a 6.8% year-over-year escalation rate in the PCIA. In the V. Risks chapter, the Study states, "Table 29 provides the current SDG&E CRS by rate class as of March 1, 2017 as used in the pro forma analysis," and "the scale of stranded assets and impact to SDG&E power procurement operations cannot be estimated." (p. 134). MRW concurs that the PCIA is highly uncertain and can have a material impacts on the cost-competitiveness of the CCA. The approach taken by Willdan is adequate, although may underestimate the PCIA in the near term and overestimate it in the longer term.

Lastly, the scenarios exploring the higher renewable content suggest, on the face, that increasing RPSC in the base rate offerings will quickly result in rates higher than SDG&E. These results are driven largely by the assumed cost of renewable energy procurement.

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

Subject to the concerns expressed in prior responses, all pertinent factors were included.

13. 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?

The Study enumerates the major risks and presents reasonable mitigations to those risks.

Power Procurement Risk: Power procurement risk includes wholesale power price spikes, uncertain load, intermittent renewable generation. The Study suggests that the CCA can mitigate risk by "having a robust power supply plan, diversifying supply portfolios by production type, generation size and location, contract length, timing of contract purchases, and the use of hedging instruments …." These are overall reasonable suggestions and should be refined and acted upon if the CCA moves forward.

Regulatory Risk: The Study accurately notes that the landscape for CCA is changing, and that these changes must be monitored.

PCIA/CRS/PAM Risk: The Study notes, **"**The implication for the CCA is that while the CCA primary power supply portfolio may be cost competitive to the existing SDG&E supply costs, the recovery of SDG&E stranded costs via PCIA and CRS fees would increase the total cost for CCA customers as they pay for both CCA power procurement and any SDG&E stranded costs from existing SDG&E PPAs." (p. 134) It further notes that these is a high degree of uncertainty in the PCIA and the large risk it generates to the CCA's ability to offer cost-=competitive rates. The Study's suggests,

> [M]itigation efforts might focus on restructuring SDG&E's contracts to relieve the utility customers of the cost obligation by acquiring a portion of those contracts for the CCA portfolio via a competitive renegotiation process. This potential risk should be further evaluated in the implementation stage of the CCA effort, with a focus on better understanding the potential stranded contract volume/cost as well as the potential for restructuring those supply contracts. (p. 135)

While MRW finds the prospect of restructuring SDG&E's contracts to be remote, we fully concur that it must be more fully evaluated if the City moves forward towards CCA implementation.

Credit Risk: The Study notes, "How the newly formed CCA will cover the upfront fixed and variable operating costs is a complex issue that must be carefully examined and *expertly* informed by a trusted, experienced Financial Advisor, preferably one that has worked with other newly formed CCAs in California and elsewhere." MRW concurs the retaining a qualified financial advisor during CCA formation and startup is absolutely necessary to ensure it gets off on solid financial footing from day one.

Opt-out risk: As shown in the sensitivity analyses, the risk of higher- or lower-than expected initial opt out is relatively modest. The Study correctly states that opt-out risk once the CCA has begun service can be minimized by competitive rates ("economic advantage"), providing good customer services ("customer experience"), and offer products and services desired by the CCA customers (e.g., easy to implement solar rooftop agreements). (p. 137)

Renewable Generation risk: The Study extensively discusses solar "over-generation" (i.e., solar generating more power during some hours than is needed by the CCA) and what is needed to integrate the solar into its overall power procurement profile. The observations in this section are accurate, and should be addressed if the CCA pursues a portfolio with particularly high solar content.

14. Does the Study provide an adequate analysis of the liabilities to the members of the CCA?

An Enterprise Fund (the City going alone) governance model allows for greater autonomy than joining with others into a JPA. Under such an approach, the City would assume all risk, liability and costs associated with operating the CCA. In this case, as recommended in the Study, the City would need to establish the CCA as an enterprise fund and work with appropriate legal counsel to implement structural safeguards to insulate it and minimize risk to the City's general fund.

As noted in the Study the JPA governance model may reduce the risks of CCA implementation by immunizing the financial assets of the City and the other participating agencies, and distributing the risks and costs associated with the CCA among the participating entities.

It is common for the largest JPA entity, often a county, to provide an initial loan to the CCA of startup cash and to backstop the financing of the initial working capital bank loan. From example, the County of Alameda has committed over $3 million to cover startup costs of the East Bay Clean Energy CCA, which it expects to have repaid once EBCE begins actual operation.

15. Are the assumptions made in the Study reasonable and adequate?

We discuss our opinions on the Study's assumptions in response to the prior questions.