Memorandum

To: Aaron Lu, Program Coordinator Sustainability Department
City of San Diego

From: Mark Fulmer, Naina Gupta and George Randolph

Subject: Update of the pro forma Modeling from "Community Choice Aggregate Feasibility Study"

Date: November 19, 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 (Feasibility Study) was requested to provide 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. Part of that Study was a pro forma analysis of CCA costs, especially relative to the cost of continued bundled service from San Diego Gas & Electric (SDG&E).

In collaboration with City staff, MRW provides this "refreshing" of the Study's pro forma for the Business Plan issued in October 2018, to reflect more recent insight into power costs and CCA issues. This memorandum provides a description of the difference between the Business Plan and the pro-forma from the original feasibility study. Beyond the Overall Results, it is organized around six pertinent changes MRW made to the inputs of the original pro-forma.

Overall Results

Figure 1 shows the Business Plan's forecast Average CCA Costs and SDG&E's generation rates. Relative to the original pro forma analysis, the Business Plan has both lower CCA costs and SDG&E rates. Thus, while both the Feasibility Study and the Business Plan find that the CCA is financially feasible, the results differ.

The bars in the chart show the forecasts of the major cost components of CCA operation, while the single line shows the forecast of SDG&E's generation rate. When the bars are below the line, the CCA's average operating costs will be below the SDG&E generation rate; meaning that it can offer power to customers at a rate lower than or competitive with SDG&E. The bottom-most green segment represents the cost of renewable power to the CCA. The renewable power costs ramp up with increasing renewable content, such that by 2035, when 100% of the power is met renewably, roughly two-thirds of the costs are for the renewable power.

The brown segment is for the costs of non-renewable, wholesale market power. This segment slowly decreases, as renewable power increases. It does not completely go away, even in 2035 when the CCA's resources are 100% renewable, because there will still be a need for generating power when renewables are not available. (The portfolio is still net 100% renewables, as renewable power generated in excess of the CCA's needs, such as sunny afternoons, offset the non-renewable market purchases.) Note that by 2035, battery storage technology may well be advanced enough so accomplish this instead, however explicit forecasts have not been made concerning the adoption and technological maturation (i.e., costs).

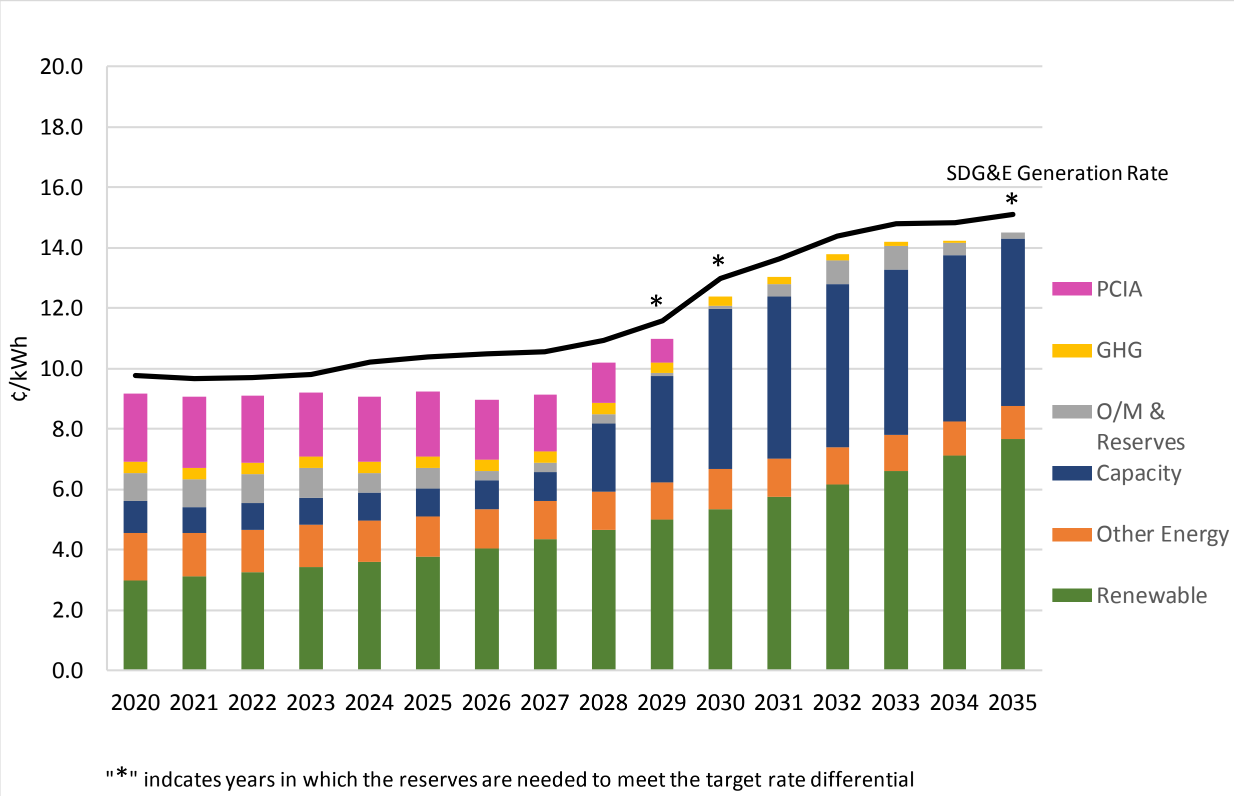
The blue segment is for capacity. That is, the CCA must demonstrate that it has the generating capacity (in megawatts) to ensure that it can serve all of its load, even if the "intermittent" renewable resources are not generating at their optimal rate (e.g., solar on cloudy days). The more intermittent renewables—solar and wind—that are added to the CCA's generating mix, the more back-up capacity is needed to ensure reliability. In the near term there is a glut of capacity in California. Thus, from 2020 through 2027 capacity costs to are low. By 2030, the capacity glut will be filled (due to increased intermittent renewables and the retirement of aging fossil plants). This will increase the capacity costs to something closer to the cost of a new combustion turbine.

The gray segment is for operations and debt service. That is, from 2021 through 2024, the loans associated with the start-up costs are paid down.

The orange segment is for carbon cap and trade allowances. Because the City of San Diego CCA's procurement is set to meet the City's Climate Action Plan of 100% renewable by 2035, the orange segment becomes nil by the end of the study period. Note that for practical purposes, the carbon cap-and-trade allowances would be built into the purchase prices of natural gas filed market resources. However, because it is an important variable on its own, the figures have separated it out.

The top-most pink segment is for the Power Charge Indifference Adjustment (PCIA), a fee paid to SDG&E to ensure that the operation of the CCA does not strand SDG&E's remaining bundled customers with costs associated with power purchased on behalf of customers who have shifted to the CCA. The Business Plan uses the formula and approach reflected in the Alternative Proposed Decision of Assigned Commissioner Carla Peterman in California Public Utilities Commission (CPUC) Rulemaking 17-06-026, which was approved by the Commission on October 11, 2018. In addition, the market price and SDG&E portfolio assumptions used in the PCIA calculations are consistent with those used to forecast SDG&E's generation rates.

Figure 1: Business Plan Rate Comparison - SDG&E vs. CCA



The Business Plan updated PCIA rates to incorporate the latest rates proposed by SDG&E, and also updated the prices of California renewable portfolio standard (RPS) compliant resources to include the most recent contract price data from 2017. Finally, the Business Plan breaks out the components that comprise the "non-renewable" portion of the CCA rate to show the wholesale market purchases and the capacity purchases that a CCA will need to make to round-off out its portfolio.

Components of Pro-Forma Business Plan

Table 1 shows the changes made and not made, in the Business Plan of the pro forma. The primary changes were with respect to pricing—rates and power prices—which were updated to reflect MRW's best current estimates.

Table 1. Differences and Commonalities Between Feasibility Study and Business Plan Assumptions/Analysis

Main Assumption/Analysis Differences	Main Assumption/Analysis Commonalities
Different pro-forma model	Load served
Power prices	Administrative Costs
PCIA	Start-up Costs
SDG&E Rates	Opt-Up to 100% renewable
Renewable Targets	
Initial Financing	

1. Differences between Feasibility Study model and the Business Plan model

The Feasibility Study used a large spreadsheet "cost of service" (COS) model. In comparing rates (i.e., how the CCA rate might compare to those offered by SDG&E), the COS model estimated the needed revenues in a "Test Year." The Test Year is designed to project the amount of revenues needed to cover anticipated costs based on a normalized year of operation. For the Feasibility Study, the Test Year Revenue Requirement equals the average projected operating costs for the first three full years of operation. It is these Test Year rates that were presented for comparison against SDG&E's generation rates.

The model used in the Business Plan is a more typical pro forma. Rather than focusing on the test year, it calculated average CCA costs over the full 25-year period. Its inputs were a bit less detailed than the Feasibility Study's COS and did not project rates for each customer type. Still, the Business Plan model is adequate for assessing feasibility, including the business plan, and comports with other CCA pro formas reviewed by MRW.

2. Updated power prices

Renewable Energy Procurement. To forecast CCA renewable energy procurement costs, the Feasibility Study employed a best-fit logarithmic curve using average utility RPS compliance costs. MRW updated these RPS costs using historic RPS contract data, specific to California publicly owned utilities (POUs) and operational CCAs. As can be seen in Table 2, the RPS prices in the Feasibility Study were extremely conservative.

Table 2: RPS Price Forecast

Year	Feasibility Study	Business Plan
2020	$89.12	$50.46
2021	$89.06	$50.46
2022	$86.17	$50.46
2023	$87.31	$50.46
2024	$86.76	$50.46
2025	$87.60	$50.46
2026	$84.99	$51.60
2027	$85.13	$52.78
2028	$86.27	$53.92
2029	$86.18	$55.06
2030	$85.98	$56.23
2031	$84.00	$57.48
2032	$83.36	$58.73
2033	$85.18	$60.02
2034	$82.55	$61.38
2035	$82.73	$62.77

Natural Gas Generation. MRW assumed that power not purchased from renewable resources would be purchased from the wholesale power market or from natural gas-fired generation at market-based prices.[1] Because natural gas is the marginal fuel in California, the market price of power is generally tied to the cost of natural gas. To forecast the prices from natural gas fired generation, the Feasibility Study fit a curve to 2002-2016 California Independent System Operator (CAISO) market-implied prices to forecast prices for the period through 2035. Based on this analysis, natural gas generation costs were forecast to decrease by 34% from $41/MWh in 2020 to $27/MWh in 2035. MRW updated this forecast to explicitly account for long-term forecasts of natural gas prices and the conversion factor to convert natural gas prices into power price, known as a "heat rate."[2] Even though natural gas prices were relatively low in 2018, the Energy Information Administration (a division of the US Department of Energy) forecasts natural gas prices for electricity generation in the Pacific region to increase by an average of 3% per year between 2020 and 2035. the Business Plan's updated forecast takes these increasing prices into account projected long term natural gas generation costs. MRW's also updated the forecast of the relationship between gas prices and power prices, assuming a smaller change in the "heat rate" that was implicitly assumed in the Feasibility Study. As a result, MRW's updated forecast shows an overall *increase* in gas prices, compared to the Feasibility Study's original downward trajectory

[1] To achieve greater GHG savings, some CCAs feasibility studies have called for the use of contracts with larger hydroelectric providers, which while not compliant as "renewable" by California law, are GHG free.
[2] This conversion factor is known as a "heat rate," and is the amount of btus (gas) that is needed to generate one kilowatt-hour of electricity.

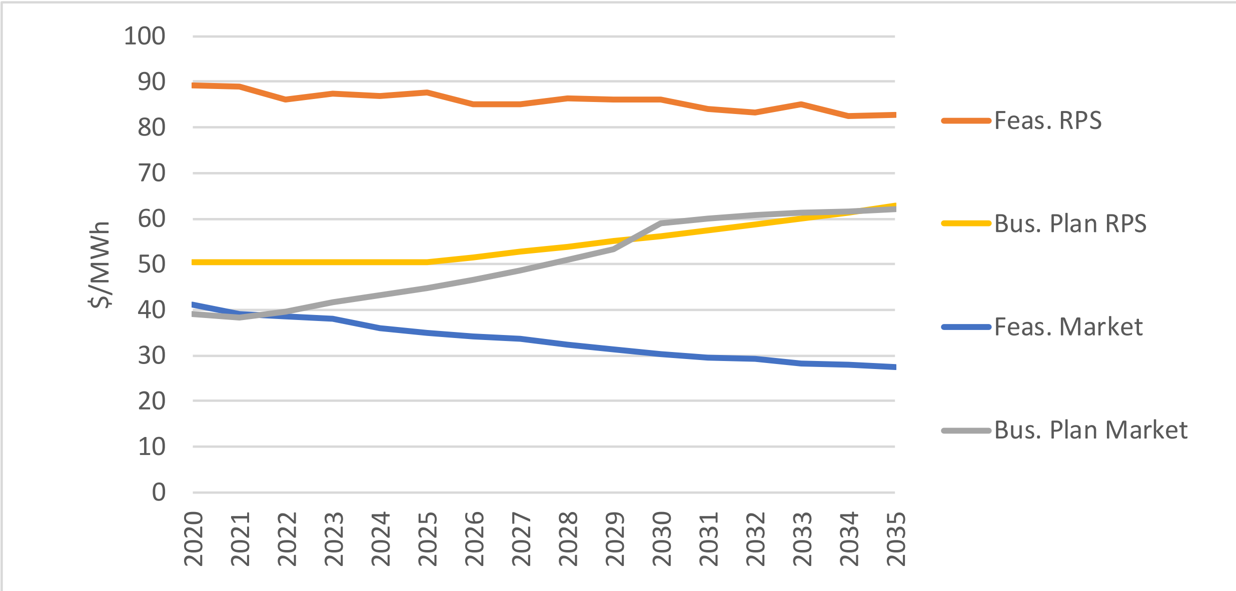
of gas prices. Table 3 summarizes the differences between the Feasibility Study's original gas prices and MRW's updated gas, or market power, prices.

Table 3: Market Power Price Forecast ($/MWh)

Year	Feasibility Study	Business Plan
2020	$41.15	$39.20
2021	$38.97	$38.21
2022	$38.44	$39.71
2023	$38.10	$41.64
2024	$35.96	$43.16
2025	$34.86	$44.85
2026	$34.19	$46.58
2027	$33.59	$48.71
2028	$32.31	$50.94
2029	$31.38	$53.28
2030	$30.40	$59.06
2031	$29.42	$60.01
2032	$29.19	$60.69
2033	$28.31	$61.23
2034	$27.91	$61.54
2035	$27.33	$62.04

Figure 2 summarizes all of these trends: the Feasibility Study's overly conservative RPS price forecast (orange line), the Business Plan RPS price forecast (yellow line), the Feasibility Study's downward trending natural gas prices (blue line) and the Business Plan 's updated natural gas price forecast (grey line).

Figure 2: Power Price Assumptions



3. Updated PCIA rates

The Feasibility Study used actual March 2017 PCIA rates to develop its PCIA rates forecast. Using the March 2017 rates as the starting point, the Feasibility Study escalated rates through 2035 using PCIA escalation rates from the EcoChoice rate forecast which was ordered by the CPUC in Decision 16-05-006[3].

The Business Plan updated the PCIA rates and forecast using the output from its in-house PCIA model. MRW's model uses the most recently available information from SDG&E regarding its power contracts and utility-owned generation, as well as forecasts of the Market Price Benchmark (which is derived using forward gas prices, GHG costs, renewable content, and capacity adders) to build a bottom-up estimate of current and future PCIA rates, taking into account contract expirations and expected changes in regulations. The PCIA model was updated shortly before the Business Plan's issuance to reflect the outcome of the California Public Utilities Commission's October decision (D.187-10-019) revising the PCIA's calculations.

MRW applied the escalation determined from this forecast to the class average PCIA rates proposed by SDG&E for each rate class in its 2018 Energy Resource Recovery Account (ERRA) forecast in November 2017[4], to determine a PCIA rate forecast for all rate classes out until 2035. MRW then weighted these rates by the load (in MWh) for each customer class in the City of San Diego to determine a system average PCIA rate forecast for the city from 2020 until 2035. Table 4 summarizes the Feasibility Study's original PCIA forecast and The Business Plan's updated PCIA forecast.

[3] As noted in The Review of the Feasibility Study, the escalate rate in the EcoChoice forecasts ordered by the CPUC were simple extrapolations of the 5-year rolling average generation rate. This is a much cruder approximation that is used in the Business Plan, which explicitly models the PCIA in a bottoms-up fashion.

[4] SDG&E Advice Letter 3167-E. (http://regarchive.sdge.com/tm2/pdf/3167-E.pdf)

Table 4: PCIA "Exit Fee" Rate Forecasts (¢/kWh)

Year	Feasibility Study	Business Plan
2020	0.01768	0.02466
2021	0.01788	0.02475
2022	0.01800	0.02316
2023	0.01860	0.02271
2024	0.01908	0.02303
2025	0.01890	0.02333
2026	0.01878	0.02241
2027	0.01883	0.02196
2028	0.01901	0.01860
2029	0.01922	0.01554
2030	0.01937	0.01107
2031	0.01948	0.01026
2032	0.01959	0.00960
2033	0.01969	0.00544
2034	0.01981	0.00316
2035	0.01993	0.00000

4. Updated forecast of SDG&E rates

To arrive at 2020 SDG&E rates, the Feasibility Study took current rates and escalated them at an annual rate of 3% to 2020. As SDG&E does not publicly release rate forecasts, the Feasibility Study relied upon the public 20-year forecast of SDG&E's EcoChoice Rate, which employs a simple 5-year rolling average as an escalator for generation rates. The Feasibility Study used this escalator on SDG&E's total rate (i.e. both generation and delivery components of the rate).

As with the PCIA rate, MRW employed a bottom-up approach to developing a forecast for SDG&E's generation rate. SDG&E will continue to provide delivery services to any CCA that comes up in the SDG&E service area, and both SDG&E customers and CCA customers will be subject to SDG&E's delivery rates. As such, MRW focused on only the generation rate component of SDG&E rates.

To determine a forecast of SDG&E generation rates, MRW used its in-house rate forecasting model. This model was developed using information regarding SDG&E's utility-owned generation, power contracts, power market costs, and by closely tracking changes in SDG&E revenues and costs through its filings in several CPUC proceedings. In particular, it takes the most recent SDG&E filing of generation rates (for 2018) and applies the known and anticipate changes to the wholesale power market and its power purchase contracts. Because the Feasibility Study relied upon extrapolations of rates, the most recent of which was 2016, it tended to overestimate SG&E's generation rate. Table 5 summarizes the forecasts for the SDG&E generation rate from the Feasibility Study as well as the Business Plan.

Table 5: SDG&E Generation Rates Forecast (¢/kWh)

Year	Feasibility Study	Business Plan
2020		0.10159
2021		0.10198
2022	0.13450	0.10178
2023	0.13925	0.10400
2024	0.14400	0.10687
2025	0.14875	0.10941
2026	0.15350	0.11331
2027	0.15825	0.11532
2028		0.12016
2029		0.12867
2030		0.14527
2031		0.15453
2032		0.16470
2033		0.17178
2034		0.17488
2035		0.18040

5. Updated phase-in period and opt-out rates for CCA

The Feasibility Study assumes initial CCA service is offered to 45% of residential and medium commercial customers, and 100% of all other commercial customers. This translates to approximately 60% of City customers or 2,600 GWh of load in the first year of CCA operation, expanding to 80% of City customers or 3,400 GWh of load in the second and third years. The Feasibility Study also assumes an opt-out rate of 20%.

The Business Plan analysis assumes a phase-in period of one year (i.e. all customers eligible and willing to participate in a City of San Diego CCA, would be brought under CCA service in 2020).[5] The Business Plan also assumes an opt-out rate of 5%, which is in keeping with prior CCA experience in California, and lower than the Feasibility Study's assumed opt-out rate of 20%. In addition, the existing Direct Access

[5] More often than not CCA's phase in their load over 2-5 years. As more experience has been gained, the need to phase-in has reduced. In addition, the phase-in method does not have a material impact on the CCA's long-term feasibility.

(DA) customers (those already taking power from non-SDG&E sources in under the limited DA program) are assumed to remain on DA.

6. Updated renewable power assumptions

The Feasibility Study assumes a 33% renewable energy content in 2020 as the base case and maintains this level of renewable penetration throughout the study period. This is in keeping with California State law that requires a minimum of 33% renewable content in a load-serving entity's portfolio by the year 2020. Different renewable energy contents are represented through different scenarios.

The Business Plan assumes a higher renewable penetration of 50% when the CCA starts operations in 2020, gradually increasing to a 100% renewable content portfolio by the year 2035. In making this update, MRW has taken into account the limitations of renewable energy (i.e., the current lack of the ability to schedule renewable capacity). As a result, a certain amount of renewable energy will need to be curtailed, or sold on the market, when generation exceeds demand. At other times, when renewable generation is not sufficient to meet demand, the CCA will need to supplement its portfolio through purchases from the wholesale power market, which will offer a mix of resources. In addition, the CCA will also need to reserve non-renewable capacity to meet its resource adequacy obligations. As a result, though the CCA is procured to meet its energy requirements through renewable sources, some non-renewable costs are unavoidable.

7. Updated financing and reserve fund assumptions

Table 6 shows the difference in the Feasibility Study and the Business Plan's quantitative assumptions concerning the CCA's initial financing, and how the CCA accrues its rate stability reserve funds.

Table 6. Differences in Financial and Reserves Assumptions (Millions $)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Contribution To Reserves											
Feas. Study	$36.6	$86.8	$96.9	$97.1	$97.8	$96.4	$97.4	$94.5	$94.8	$94.3	$94.0
Bus. Plan	$61.5	$3.8	$2.3	$1.9	$1.8	$1.7	$0.0	$1.3	$14.9	$12.3	$17.2
Debt Service											
Feas. Study	$17.5	$17.5	$26.3	$26.3	$26.3	$26.3	$26.3	$26.3	$26.3	$26.3	$26.3
Bus. Plan	$0.0	$24.5	$24.5	$24.5	$24.5	$24.5	$0.0	$0.0	$0.0	$0.0	$0.0

Financing

The Feasibility Study assumed the CCA startup and initial cash infusion would come from a long-term (30 year) bond to fund the $363 million cash operating and reserve requirements, plus all bond issuance costs, capitalized interest, and a required bond reserve fund. The forecasted bond interest rate is 4.0%. Given the uncertainty related to power costs, the PCIA, and opt out rates for customers, the Feasibility

Study assumed the CCA would defer principal payments for two years and use capitalized interest funding received from the bond proceeds to cover the first two annual interest payments of approximately $17.5 million per year ($35 million total for the first two years). The remaining years' payments over the 30-year bond term would include interest payments and outstanding principal payments.

Table 7: Feasibility Study's Debt Issuance and Annual Debt Service Assumptions

Feasibility **Study Funding Requirement**	**Total Initial**
Operating Expenses	$271,560,634
Currency, Rate Stabilization Fund	91,860,989
Total CCA Funding	$363,421,623
Bond Reserve Fund	$26,277,535
Capitalized Interest	35,029,138
Issuance Costs	13,135,926
Other Bond Proceeds	$74,442,599
Total Bond Issuance	**$437,864,222**

The Feasibility Study simply says "the CCA" would issue the bonds. However, given that the CCA would be a new entity without any credit rating or financial history, the bond in practice would need to be issued by the City. Were the City forming a new municipal utility, this financing option might be more appropriate.

The Business Plan assumes a more conventional initial financing: the CCA would borrow, with the credit support of the City an amount to pay off any start-up cost liabilities plus sufficient working capital funds. This loan is assumed to be paid off, with interest, within the first five years of CCA operation. This is the process followed by all of the current operating CCAs.

Reserves

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 Feasibility Study's pro forma analysis appears to assume that approximately $97 million (14% of total expenses) is contributed *each year.* In the context of the model, this isn't surprising: it is set to create a "test year" revenue target so that rates can achieve the target in the "test year." It doesn't make any assumptions about years beyond the test year, such as that the reserves were not spent. Thus, the Feasibility Study's reserve assumption can be seen as very conservative (i.e., continually needing large infusions).

The Business Plan sets a target (approximately 15% of annual expenses), takes 3 to 5 years to achieve the fund, and then reduces further contributions until replenishment is needed. This is the approach that has been taken by the current operating CCAs.

Conclusions

The Business Plan of the pro forma analysis confirms the original Feasibility Study's general conclusion that a CCA was feasible, forecasting CCA rates to be lower than SDG&E's rates. As the City further considers CCA formation, MRW recommends that that the pro forma be updated to reflect changes in market prices, SDG&E rates (the PCIA), and any assumptions more accurately reflecting likely CCA costs (e.g., administration, financing and start-up), power procurement, and customer phase in.