Memorandum

To: Ashley Watkins, Division Chief, Sustainability, County of Santa Barbara

From: Pacific Energy Advisors, Inc.

Subject: Community Choice Aggregation Technical Study Update

Date: June 14, 2019

Executive Summary

In May 2018, a Community Choice Aggregation (CCA) Technical Study (Study) was prepared for the County of Santa Barbara (SBC or the County), by Pacific Energy Advisors, Inc. (PEA) under contract with SBC, for purposes of determining the potential feasibility of forming a CCA program within all or part of Santa Barbara County.[1] The Study evaluated three membership configurations. Under each membership configuration, three distinct supply scenarios were evaluated, each reflecting varying levels of renewable energy[2] and greenhouse gas (GHG)-free energy[3] supply as well as associated costs.

Several developments have led SBC to request an update to the original Study, addressing revised membership and updates to key market and regulatory assumptions. The updated analysis (Update) examines the feasibility of a CCA program serving the unincorporated areas of the County as well as the Cities of Carpinteria, Goleta, and Santa Barbara. The analysis also reflects revised assumptions related to utility rates and wholesale electricity prices as well as revisions related to the recent California Public Utilities Commission (CPUC) proceeding that reformed the methodology for calculating the Power Charge Indifference Adjustment (PCIA).[4] As instructed, PEA modeled a CCA supply portfolio that would exceed the renewable energy and GHG-free content of the expected electric supply portfolios to be offered by the incumbent investor-owned utilities, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE). The CCA is modeled with an 85% GHG-free supply portfolio, with qualifying renewable energy content starting at 50% and increasing to 60% by 2030, as required by the state Renewables Portfolio Standard (RPS).

The Update assesses the potential CCA over an 11-year study period: 2021-2031. The CCA is assumed to start operations in 2020 in preparation for CCA-sourced electricity to begin flowing to customers in 2021, the earliest year that service could begin in light of CPUC timing requirements.[5]

Based on the analyses conducted during this Update, PEA concludes that SBC could operate a CCA

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[1] The original Study is available at: http://www.centralcoastpower.org/resources.nrg#fasibility.

[2] As defined by the State Renewables Portfolio Standard (RPS).

[3] GHG-free electricity refers to electric energy generated from sources that do not emit (or emit very low amounts of) gases which contribute to the greenhouse effect, such as carbon dioxide, methane, and nitrous oxide. GHG-free power sources typically include RPS-eligible renewable energy and hydroelectric generating resources.

[4] The PCIA is a charge the incumbent utility imposes on CCA customers for generation commitments made prior to the time the customer takes generation service from the CCA. The PCIA rates are approved by the CPUC.

[5] The original study assumed service would commence to customers in 2020.

program providing competitively priced electricity, sourced from predominantly non-carbon emitting electric generation sources. The prospective CCA could set rates equal to PG&E and SCE. However, at rate parity, the CCA would accumulate financial reserves smaller than levels achieved by other CCAs that were formed in the last few years. These comparatively smaller reserves would provide less financial security against unexpected cost shocks. Further, to address early year operating losses, the initial financing for program operations may require a guarantee or other form of credit support provided by the JPA members. Accelerating reserve contributions could build healthier reserves but would require higher rates charged to customers or other funding sources as further discussed below. Alternatively, a program initially targeted to residential customers would be more financially viable, with stronger operating profits, healthier reserve levels, and lower financing requirements.

Ultimately, SBC's ability to demonstrate rate competitiveness (while also offering environmental benefits) would hinge on prevailing market prices at the time of power supply contract negotiation and execution. Depending on inevitable changes to market prices and other assumptions such as IOU generation rates and the PCIA, SBC's actual electric rates may be somewhat lower or higher than similar rates charged by the IOUs and would be expected to fall within a competitive range needed for program viability.

Introduction

This Update addresses the potential benefits and liabilities associated with forming a County-based CCA program over an eleven-year planning horizon (2021-2031). The CCA is assumed to commence preliminary operational activities in 2020 in preparation for CCA-sourced electricity to begin flowing to customers in 2021, the earliest year that service could begin in light of CPUC timing requirements. The original Study assumed service would begin in 2020.

Projected operating results are dependent upon a variety of factors and assumptions, including but not limited to:

- Recent wholesale energy and capacity product pricing and availability;
- The County's desired electric power portfolio composition, which is expected to include significant use of renewable energy and other GHG-free energy sources;
- Anticipated retail generation rates of SCE and PG&E, the incumbent IOUs within the County;
- Estimated PCIA rates and other surcharges, or exit fees, which are imposed on CCA customers;
- Expected financing and administrative costs of the CCA program;
- Other cost elements at the time of assessment completion; and
- PEA's extensive direct experience with many of California's operational CCA programs.[6]

As requested by SBC, communities to be served by the prospective CCA initiative include the unincorporated areas of Santa Barbara County and the Cities of Carpinteria, Goleta, and Santa Barbara. PEA was tasked with updating the pro forma analysis assuming the electricity portfolio begins with 50% renewable energy and increases to 60% renewable energy in 2030, as required by the State RPS. Using this baseline, PEA examined general rate competitiveness and financial viability of a CCA program serving the jurisdictions listed above in light of recent market and policy changes.

[6] PEA has unique experience with California CCA program evaluation, development and operation, having provided broad functional support to many operational California CCAs, including Marin Clean Energy, Sonoma Clean Power, Lancaster Choice Energy, CleanPowerSF, Peninsula Clean Energy, Silicon Valley Clean Energy, Pioneer Community Energy, Monterey Bay Community Power and several others.

Regulatory Environment

Rapid acceleration of CCA throughout the state has heightened regulatory and legislative focus on these relatively new entities, resulting in a general increase in regulation of CCAs. Recently, the CPUC has taken an expansive view of its regulatory authority over CCA resource planning. Despite CCA objections regarding the CPUC's legal authority to regulate CCA procurement, the CPUC appears intent on extending certain elements of the regulatory framework, which have been historically applied to investor-owned utility resource planning, to CCA organizations as well. Up to this point, increases in CPUC-administered regulatory requirements have taken the form of expanded reporting obligations, which generally increase costs associated with regulatory compliance while disproportionately impacting small CCA programs. Of greater concern is the CPUC's apparent inclination to exert increased control over CCA resource procurement decisions in such forums as the Integrated Resource Planning proceeding and the Resource Adequacy proceeding. Additionally, policymakers have made proposals and proposed legislation to establish a "central buyer" with responsibility for procurement of certain "preferred" resources, with such costs spread to all load serving entities. If unchecked, these trends threaten CCA resource planning and procurement autonomy. With the growing political power of CCAs, evolution of the regulatory environment will likely balance CCA interests with the State's interest in maintaining control over the electric system. In the meantime, the regulatory environment remains highly fluid and will undoubtedly undergo significant change over the next several years; by forming a CCA, SBC should be prepared for active participation in shaping statewide and local energy policy in order to maintain long-term operational viability.

Another recent regulatory development includes the limited re-opening of direct access, which allows bundled customers the ability to receive generation service from private energy services companies, beginning in 2021. Statewide, a total of 4,000 GWh (annual energy sales) allowed for new direct access transactions will be apportioned among the respective investor-owned utility service territories. The expansion represents an approximately 15% increase in direct access eligible load. PEA does not anticipate material changes to the SBC CCA pro forma resulting from this expansion of direct access.

The RPS requirements that would be applicable to an SBC CCA have increased as a result of the enactment of Senate Bill 100, increasing to 60% by 2030 from the previous 50% requirement. The new RPS requirements have been reflected in this update. Further, the SBC CCA will need to demonstrate it has long-term (10 years or longer) contracts for at least 65% of its renewable portfolio requirements for the compliance period commencing on January 1st, 2021 as well as each compliance period thereafter. The long-term contracting requirement may be challenging for a newly operating CCA because the CCA's credit profile tends to build over time, and long-term contracts pose significant credit exposure to the sellers. Security arrangements such as a "lockbox" or alternative credit support structure for securing buyer obligations under the long-term contract(s) would need to be explored during the implementation phase.

SBC's Prospective Customers

Currently, electric customers within SBC are served by either SCE or PG&E, depending on the geographic area in which such customers reside. Collectively, the IOUs serve approximately 112,400 combined electric accounts (85,400 by SCE, and 27,000 by PG&E) within the member communities of Santa Barbara

County, representing a mix of residential (≈84%), commercial (≈14%) and agricultural (≈2%) accounts.[7] These customers consume nearly 2.1 billion kilowatt-hours ("kWh") of electric energy each year.[8] While the majority of customers fall under the residential classification, such accounts historically consume only 26% of the total electricity delivered by the IOUs. The balance of SBC's historical electricity sales (≈74% of the total) are substantially related to commercial (≈29%), industrial (≈35%) and agricultural (≈10%) usage. The current utility rate structures generally charge the lowest rates to large commercial, industrial, and agricultural customers, and the prevalence of these customers in SBC results in lower overall margins available to the CCA program.

Under CCA service, each of these accounts could be enrolled in the SBC program; the precise timing of customer enrollment, and any related phasing decisions of the CCA program, if any, would be determined during the implementation period. For purposes of this Update, it was assumed that all customers would be enrolled during the month of January 2021, which is the earliest time that a CCA program could launch under current State regulations.[9]

Consistent with California law, customers may elect to take service from the CCA provider or remain with SCE or PG&E, a process known as "opting-out." For purposes of the Update, PEA utilized current participatory statistics compiled by California's operational CCA programs to derive an assumed participation rate of 90% for the SBC program; the remaining 10% of regional customers (not including Direct Access customers, which would not be enrolled by the CCA program for purposes of avoiding duplicative customer charges and/or contractual issues for such accounts) are assumed to opt-out of the SBC program and would continue receiving generation service from the IOUs. Customer account and energy usage projections referenced throughout this Update reflect such adjustment.

SBC's Indicative Supply Portfolio

For purposes of the Update, PEA modeled a supply portfolio that would improve upon the status quo for use of renewable energy, relative to assumed portfolio compositions of the incumbent IOUs, as well as related metrics for GHG emissions intensity. The SBC supply portfolio is initially comprised of 50% qualifying renewable energy, increasing to 60% by 2030, in accordance with the requirements of SB100.[10]

Overall GHG-free content for the prospective CCA program is held steady at an average of 85% throughout the study period. As indicated in the original Study, PG&E is expected to maintain a substantially GHG-free resource mix, approaching 100% in the near term, at least until retirement of the Diablo Canyon nuclear power plant occurs in 2024-2025. With this in mind, the prospective CCA supply portfolio assumes 100% GHG-free energy for load served in the PG&E service area and 75% GHG-free energy for load served in the SCE service area, resulting in an overall GHG-free content of 85% for the CCA's composite supply

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[7] Prospective account totals reflect only bundled customers served exclusively by the applicable IOU and exclude Direct Access customers who procure their electricity supply from a provider other than PG&E or SCE. Of note, the University of California, Santa Barbara is included as a bundled SCE customer. However, staff has indicated that the university is expected to become a Direct Access customer and therefore will likely not be served by the CCA.

[8] Reflects bundled customer electricity usage in calendar year 2015.

[9] This timing assumes participating member agencies form a JPA and submit a CCA Implementation Plan & Statement of Intent to the CPUC before January 1, 2020.

[10] Consistent with California's RPS laws, retail sellers of electric energy, including CCAs, must procure a minimum 33% of all electricity from eligible renewable energy sources by 2020; with the recent enrollment of Senate Bill 100, California's RPS procurement mandate has been increased to 60% by 2030.

portfolio.

The various energy supply components of the modeled supply portfolio are broadly categorized as:

- Conventional Supply (generally, electric energy produced through the combustion of fossil fuels, particularly natural gas within the California energy market);
- "Portfolio Content Category 1 (PCC1)" or "Bucket 1" Renewable Energy Supply (generally renewable energy produced by generating resources located within or delivering power directly to California);
- "Portfolio Content Category 2 (PCC2)" or "Bucket 2" Renewable Energy Supply (generally renewable generation produced outside of California with associated energy import requirements);
- "Portfolio Content Category 3 (PCC3)" or "Bucket 3" Renewable Energy Supply (environmental attributes of metered renewable energy production, conferred in the form of a renewable energy certificate (REC), which is sold separately from the electric power; Bucket 3 renewable energy is commonly produced outside of California and is colloquially referred to as an "unbundled REC"); and
- Additional GHG-Free Supply (generally power produced by regionally located hydroelectric generating facilities, which do not meet the eligibility requirements of California's RPS program – such requirements render larger hydroelectric generators in excess of 30 MW ineligible to participate in California's RPS program).

As in the original Study, the renewable energy to be procured by the CCA is predominantly assumed to be from sources and contracts meeting the definition/delivery requirements of PCC1, which are typically located within California. The volumes of renewable energy modeled as PCC2 and PCC3, which are supplied from out of state renewable generators, were limited to 15% and 10% of applicable Renewables Portfolio Standard requirements, respectively. This translates to an overall portfolio content of 5.4% PCC2 and 3.6% PCC3 in year 1 (2021) and 9.0% PCC2 and 6.0% PCC3 in year 11 (2031). All PCC2 and PCC3 volumes are matched by additional purchases of other GHG-free (large hydro) energy to ensure that targeted GHG-free targets are met. [11] PEA encourages the County to actively monitor implementation activities associated with AB 1110 to ensure that any eventual procurement decisions made by the CCA program appropriately consider the final methodological guidelines adopted by the California Energy Commission (for power source reporting and related portfolio emissions calculations), which may somewhat differ from those assumptions reflected in this Update.

[11] Industry accepted GHG accounting practices generally recognize eligible renewable energy sources as GHG-free. However, California's ongoing implementation of Assembly Bill 1110 (Ting, 2016) will alter such practices, imposing a new retail-level GHG emissions calculation methodology that may eliminate the emissions benefits historically attributed to certain renewable energy products. In particular, the California Energy Commission's staff proposal regarding AB 1110 implementation suggests that many Bucket 2 renewable energy products and all Bucket 3 products would be ascribed a non-zero GHG emissions rate generally equivalent to system-wide purchases. Specific details regarding AB 1110 implementation remain under development and will not be finalized until later in 2019. Note that AB 1110 will be effective for all power purchases occurring on and after January 1, 2019. Also, under all supply scenarios, incremental purchases of non-RPS-eligible GHG-free sources, specifically electricity produced by larger hydroelectric resources (with nameplate generating capacity in excess of 30 megawatts) would be procured by SBC to achieve targeted GHG emissions reductions.

Figure 1: Indicative Supply Portfolio Composition PG&E Territory

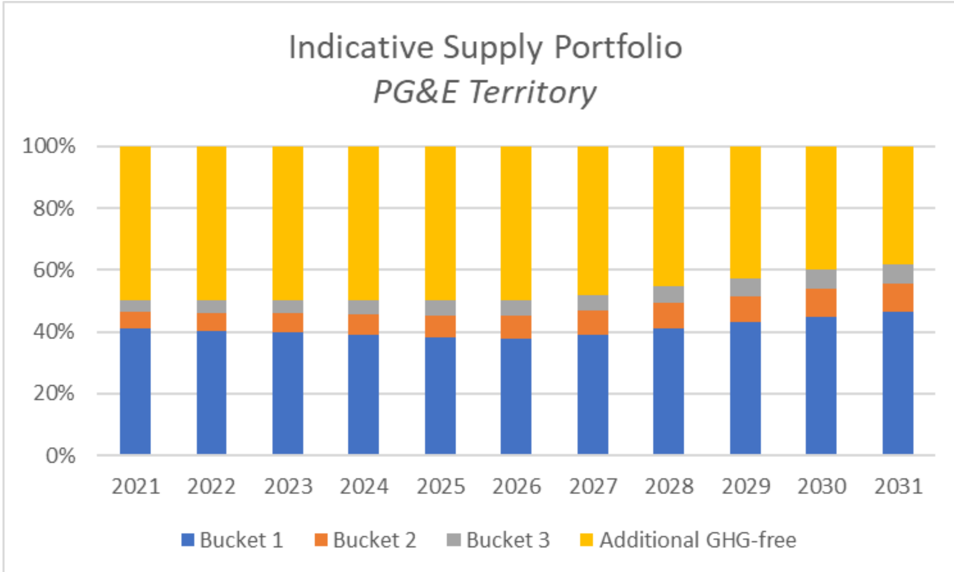
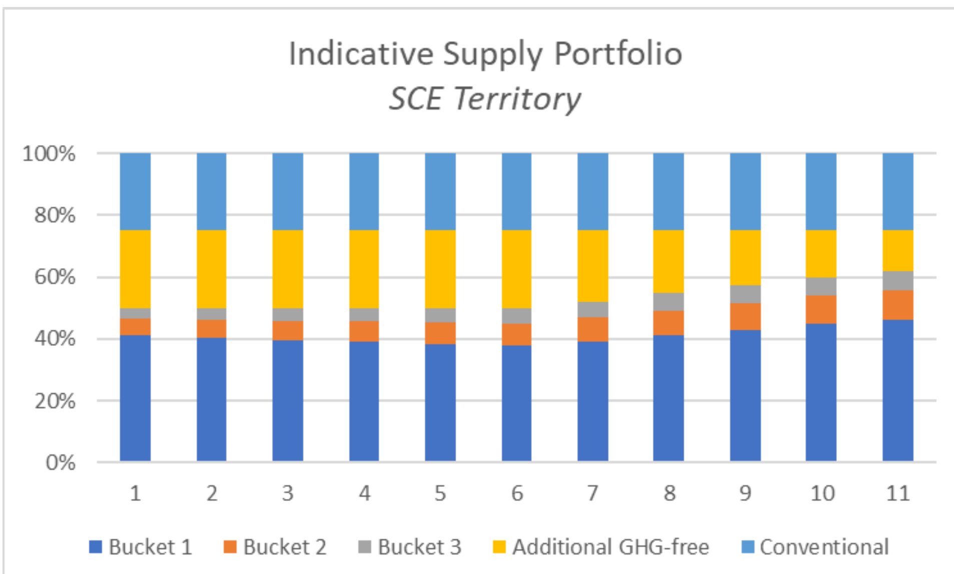


Figure 2: Indicative Supply Portfolio SCE Territory



It should be noted that SBC would not be limited to the particular portfolio assessed in this Update. The studied portfolio serves to demonstrate the potential operating outcomes of a new CCA program that would offer a cleaner supply portfolio than the incumbent utilities, while balancing ratepayer costs. Prior to the procurement of any particular energy product(s), SBC would have an opportunity to refine its desired resource mix, which may differ from the portfolio choices reflected herein.

General Operating Projections

The pro forma financial projections contained in Exhibit 2 indicate the expected revenues and costs associated with CCA program operation, assuming that CCA generation rates are set at parity with projected rates of the incumbent utilities. Positive operating margins are projected to begin in the third year of program operations, and achievement of a targeted reserve balance equal to 40% of annual operating expenses is projected to occur in Year 11 (2031). Reserve levels average around $7 million during the first four years of CCA program operation, before beginning a growth trajectory during which reserves grow to approximately $77 million by 2031. The expected increase in reserve levels is partly the result of anticipated increases in PG&E generation rates around 2025, the time when decommissioning of PG&E's Diablo Canyon nuclear power plant is expected to occur.[12]

In Exhibit 2, the projected "Actual Reserve Contribution" during each year of the study period reflects the projected net revenues (or deficits) that would be realized by the SBC CCA if the program decided to offer customer electric rates that were equivalent to similar rates charged by the IOUs. To the extent that the Actual Reserve Contribution is equal to or greater than the targeted reserve contribution, SBC would have the potential to offer comparatively lower customer rates/charges, relative to similar rates imposed by the IOUs; to the extent that the Actual Reserve Contribution is less than the targeted reserve contributions, SBC would need to impose comparatively higher generation rates to recover expected costs, or operate with a lower than desired operating reserve. The Actual Reserve Contribution is higher than the 4% of annual revenues target in 7 years and lower than the target contribution in 4 years.

The initial results for the combined-IOU pro forma indicate positive operating margins beginning in year 3 (2023) and below targeted reserve accumulation for the first four years of program operations. Consequently, during this period there would be relatively few financial reserves available to ensure rate stability by absorbing fluctuations in revenues or power costs. Operating margins are projected to strengthen in 2025, due in part to expected rate increases associated with closure of Diablo Canyon, and PG&E's need to replace this energy at prevailing market prices. A cumulative reserve balance equal to 40% of annual operating costs is projected by year 11 (2031).

If CCA rates were set independently of the incumbent utilities' rates, and instead were designed to fully recover costs and contribute 4% of annual revenues to reserves (the reserve contribution level used in the original Study and common among CCAs), such CCA rates are projected to be 3% higher on average than the incumbent utilities' generation rates for the first four years of CCA program operations, before falling to rate parity (or below) thereafter.[13] It should be noted that a 3% generation cost premium would translate to an overall bill impact (including generation and delivery charges) of approximately 1.5%, a level which PEA considers competitive and not likely to materially impact customer participation. Rates can be competitive without necessarily being lower as the CCA could provide numerous benefits to the community in the form of reduced GHG emissions, innovative local programs, and local control over key energy policies. These benefits may be worthy of community investment, either in the form of temporarily higher rates or through direct member funding to augment the program's initial reserves.

[12] As indicated in PG&E's 2018 Integrated Resource Plan (https://www.pge.com/en_US/for-our-business-partners/energy-supply/integrated-resource-plan/integrated-resource-plan.page?WT.mc_id=Vanity_irp).

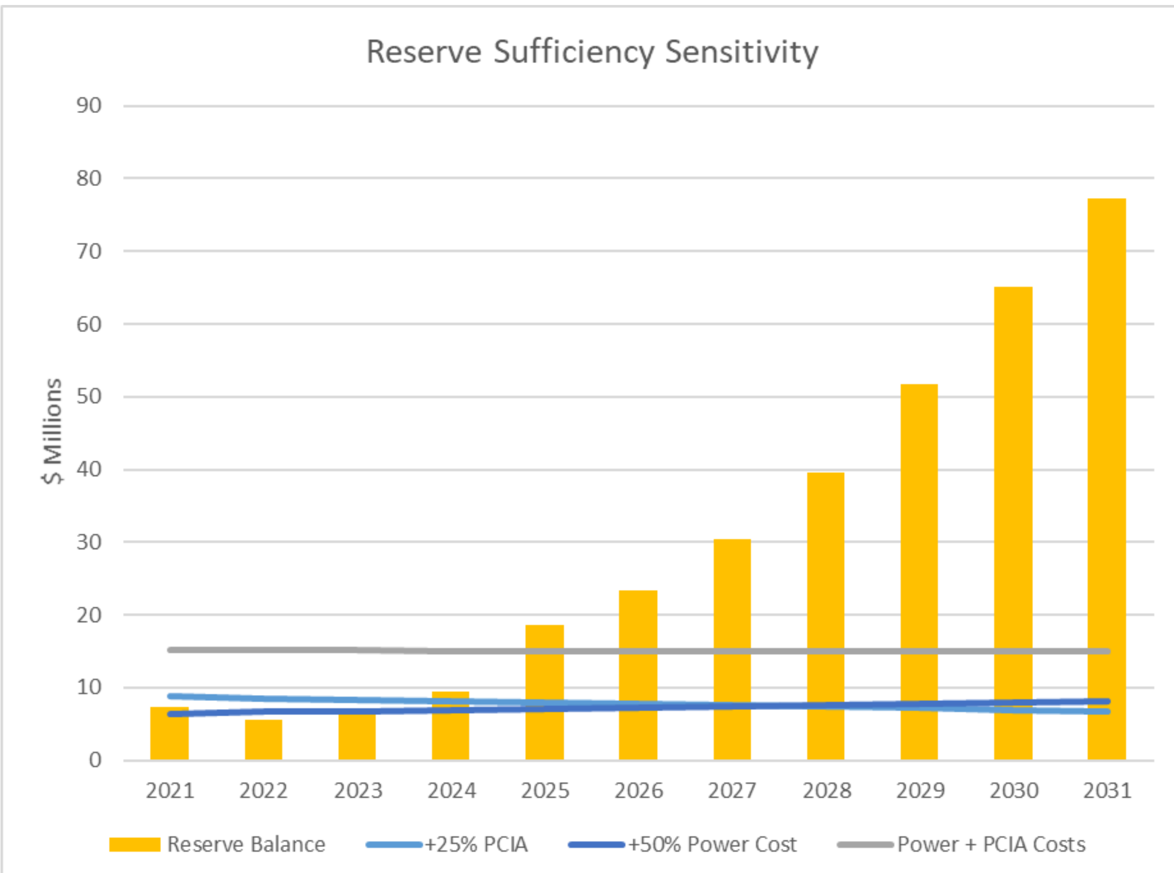
[13] The rate premium is assumed to apply on a uniform percentage basis to all customers served by the SBC CCA. Actual rate design would be under the discretion of the SBC CCA Governing Board.

Sensitivity Analysis

In response to SBC's request to better understand the ability of the modeled reserve fund to weather adverse changes in power prices and PCIA costs, PEA performed sensitivity analyses involving the variability of those costs. The increased cost was evaluated by year relative to accumulated reserves. Baseline PCIA projections comprise approximately 20% of the CCA customer's generation costs. To represent a reasonable range of outcomes, PCIA costs were increased by 25% relative to the baseline projections. Power costs were stressed assuming a 50% increase in costs associated with the CCA program's annual open position, which is expected to be approximately 10% of total energy requirements during each year of program operation.[14]

When compared to Accumulated Reserve Levels, a 50% increase in spot market power costs could be fully absorbed as early as 2021, and a 25% increase in PCIA could be absorbed by 2024. In the unlikely event that both contingencies were to occur at the same time, the accumulated reserve balance would be sufficient to cover the combined cost increase beginning in 2025. Further details can be seen in Figure 3.

Figure 3: Reserve Sufficiency Sensitivity



[14] Assumes minimum of 90% fixed priced coverage for all power supply costs in any given year. Volatility on power prices was derived using historical prices over the past 10 years, which captures the market movements during the natural gas boom/bust and the Great Recession. In order to capture extreme movements, the prices were stressed using a 95% confidence interval. The PCIA sensitivity is similarly expected to capture a range of reasonably likely outcomes for that cost variable.

Reserve Summary											
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Reserve Balance	7	6	7	9	19	23	30	40	52	65	77
+50% Power Cost	6	7	7	7	7	7	7	8	8	8	8
+25% PCIA	9	9	8	8	8	8	8	7	7	7	7
Power + PCIA Costs	15	15	15	15	15	15	15	15	15	15	15

Alternate Customer Mix Sensitivity

An alternative scenario was developed to examine the viability of the SBC CCA program offering service exclusively to residential customers in recognition of the higher per unit margins embedded in current utility rate designs for this customer class. This scenario utilizes the same supply portfolio parameters and assumes service is offered to all residential customers at generation rates equivalent to those charged by the incumbent utilities. Per law, the SBC CCA program would be obligated to offer service to all residential customers, but no such service obligation extends to other customer classes. Staffing and certain other administrative costs were reduced in this scenario, consistent with the narrower customer segment served by the CCA. Financing requirements were also reduced due to lower startup costs and positive cash flows.

Focusing the program on residential customers is projected to yield improved financial performance. The pro forma projections indicate positive operating margins beginning in year 1 (2021) and above targeted reserve accumulation in 9 of the 11 years in the study period. A cumulative reserve balance equal to 40% of annual operating costs is projected to be achieved in year 7 (2027).

Findings and Conclusions

Based on the updated analyses, PEA finds that a prospective CCA program for Santa Barbara County appears financially viable, and that competitive rates could be offered, while supplying a highly renewable and largely GHG-free energy mix. Projected operating margins are lower than the original Study's projections due to the revised membership configuration with lower CCA load in the PG&E service area, the CPUC's recent revisions to the PCIA methodology, and generally higher wholesale energy costs prevailing since the time of the original Study. Consequently, projected reserve contributions under an 85% GHG-free supply scenario, with rates set to achieve parity with the incumbent utilities, are below industry norms.[15] This could be addressed by charging higher rates; by the member municipalities contributing additional funding to seed program reserves; or by targeting program eligibility to residential (and possibly small commercial customers) until such time as it becomes economic to serve the larger commercial and industrial customer base.

Ultimately, SBC's rate competitiveness (while also offering environmental benefits) would hinge on prevailing market prices at the time of power supply contract negotiation and execution. Depending on inevitable changes to market prices and other assumptions, such as IOU generation rates and exit fees (i.e., the PCIA), SBC's actual electric rates may be somewhat lower or higher than similar rates charged by the IOUs and would be expected to fall within a competitive range needed for program viability.

[15] Common practice for operating CCAs in California is to target a minimum annual reserve contribution of 4% of revenues, building toward a reserve balance of at least 40% of annual operating expenses. Some CCAs, particularly those operating in the PG&E service area, have been able to achieve much higher reserve contributions in recent years, due to relatively high utility rates and low wholesale market prices. Going forward, PEA expects reduced operating margins across the industry.

EXHIBIT 1 – KEY ASSUMPTIONS

Generally

Unless otherwise noted, all assumptions are the same as the original Study delivered in 2018.

- Customer opt-out rate of 10% for all scenarios.
- Start-up costs of approximately $9 million (consisting predominantly of 72% working capital, and 28% startup costs), funded by a 3% interest revolving credit line, assumed to be retired after ten years. It is likely that the startup portion would require a guarantee by the members and possible that the working capital portion would as well. In the residential-only sensitivity scenario, total financing is reduced to $2.5 million and retired after eight years.
- Targeted annual reserve contributions fixed at 4% of annual revenue. Cumulative reserve target fixed at 40% of annual operation expenses.
- Based on published market prices and recent transactions for similar energy products, average energy costs were modeled as follows:

PG&E ($/MWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Shaped Energy	$ 45.23	$ 45.97	$ 46.40	$ 47.07	$ 47.97	$ 48.96	$ 49.45	$ 49.95	$ 50.45	$ 50.95
Bucket 1	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00
Bucket 2	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50
Bucket 3	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00
System RA ($/KW-Mo)	$ 4.95	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45
Bay Area RA ($/KW-Mo)	$ 5.32	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85
Other PG&E RA ($/KW-Mo)	$ 5.32	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85
Carbon Free Premium	$ 3.18	$ 3.28	$ 3.38	$ 3.48	$ 3.58	$ 3.69	$ 3.80	$ 3.91	$ 4.03	$ 4.15

SCE ($/MWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Shaped Energy	$ 42.55	$ 43.41	$ 44.03	$ 44.77	$ 45.73	$ 46.75	$ 47.22	$ 47.69	$ 48.17	$ 48.65
Bucket 1	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00	$ 17.00
Bucket 2	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50	$ 6.50
Bucket 3	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00
System RA ($/KW-Mo)	$ 4.95	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45
LA Basin ($/KW-Mo)	$ 5.32	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85
BC/Ventura ($/KW-Mo)	$ 5.32	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.85
Carbon Free Premium	$ 3.18	$ 3.28	$ 3.38	$ 3.48	$ 3.58	$ 3.69	$ 3.80	$ 3.91	$ 4.03	$ 4.15

- No utility-scale local generation supply sources were assumed within Santa Barbara County. Bucket 1/PCC1 supply is generally from in-state renewable resources, Buckets 2 and 3 are from out-of-state sources, and additional GHG-free supply is assumed to come from large hydroelectric generators located in California and throughout the Pacific Northwest.
- Approximately 15% of SBC's retail load would be from unspecified system energy and purchases from the CAISO market.
- The required CCA bond is assumed at $147,000, consistent with current requirements.
- Annual staffing costs were derived by benchmarking to currently operating CCAs of similar size; estimated at $3,000,000, with corresponding staffing levels of approximately 17 full time equivalents. In the residential-only sensitivity scenario, staffing costs are estimated at $1,800,000, with corresponding staffing levels of approximately 10 full time equivalents.
- All scenarios consider a single phase of customer enrollments.
- Uncollectable debts are assumed at 0.5% of revenue, consistent with current bad debt levels seen by other CCAs.

- No voluntary 100% opt-up renewable energy program was modeled; the estimated impact of offering a voluntary opt-up program is de minimus with respect to portfolio planning and program finances.
- The impact of Distributed Energy Resources on CCA load is considered to the extent that it will be offset by growth in other areas such as the increase in demand from electric vehicles.

SCE Inputs

Annual Rate Growth[16]

- Generation rates (net of CRS):

SCE Generation										
Annual Average Rates ($/MWh)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
D	$ 81.73	$ 84.12	$ 86.54	$ 88.99	$ 91.46	$ 93.96	$ 96.49	$ 99.06	$ 101.65	$ 104.28
GS-1	$ 77.50	$ 79.64	$ 81.80	$ 83.99	$ 86.20	$ 88.45	$ 90.72	$ 93.02	$ 95.35	$ 97.72
TC-1	$ 61.62	$ 63.39	$ 65.18	$ 66.98	$ 68.81	$ 70.66	$ 72.54	$ 74.44	$ 76.36	$ 78.31
GS-2	$ 65.29	$ 67.19	$ 69.11	$ 71.05	$ 73.02	$ 75.00	$ 77.02	$ 79.05	$ 81.12	$ 83.21
TOU-GS	$ 60.81	$ 62.59	$ 64.39	$ 66.21	$ 68.05	$ 69.91	$ 71.80	$ 73.70	$ 75.63	$ 77.59
TOU-8-Sec	$ 57.25	$ 58.95	$ 60.67	$ 62.40	$ 64.15	$ 65.93	$ 67.72	$ 69.54	$ 71.37	$ 73.23
TOU-8-Pri	$ 56.01	$ 57.67	$ 59.35	$ 61.04	$ 62.76	$ 64.49	$ 66.24	$ 68.02	$ 69.81	$ 71.63
TOU-8-Sub	$ 50.07	$ 51.58	$ 53.11	$ 54.65	$ 56.20	$ 57.78	$ 59.37	$ 60.98	$ 62.61	$ 64.26
TOU-PA-2	$ 54.47	$ 56.11	$ 57.77	$ 59.45	$ 61.14	$ 62.85	$ 64.59	$ 66.34	$ 68.11	$ 69.91
TOU-PA-3	$ 48.83	$ 50.34	$ 51.87	$ 53.41	$ 54.96	$ 56.53	$ 58.12	$ 59.73	$ 61.36	$ 63.00
Street Lights	$ 37.66	$ 38.92	$ 40.19	$ 41.47	$ 42.76	$ 44.06	$ 45.38	$ 46.71	$ 48.05	$ 49.41

- Exit fees (Cost Responsibility Surcharge):

Cost Responsibility Surcharge										
SCE Average Rates ($/MWh)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
D	$ 16.09	$ 15.65	$ 15.22	$ 14.81	$ 14.42	$ 14.03	$ 13.66	$ 13.30	$ 12.95	$ 12.61
GS-1	$ 12.55	$ 12.21	$ 11.89	$ 11.57	$ 11.27	$ 10.97	$ 10.69	$ 10.41	$ 10.15	$ 9.89
TC-1	$ 11.39	$ 11.08	$ 10.78	$ 10.50	$ 10.22	$ 9.94	$ 9.68	$ 9.43	$ 9.18	$ 8.95
GS-2	$ 12.63	$ 12.28	$ 11.95	$ 11.63	$ 11.32	$ 11.02	$ 10.72	$ 10.44	$ 10.17	$ 9.91
TOU-GS	$ 11.98	$ 11.65	$ 11.34	$ 11.03	$ 10.74	$ 10.45	$ 10.17	$ 9.90	$ 9.64	$ 9.39
TOU-8-Sec	$ 11.68	$ 11.37	$ 11.06	$ 10.76	$ 10.47	$ 10.19	$ 9.92	$ 9.65	$ 9.40	$ 9.15
TOU-8-Pri	$ 11.39	$ 11.08	$ 10.78	$ 10.49	$ 10.20	$ 9.93	$ 9.67	$ 9.41	$ 9.16	$ 8.93
TOU-8-Sub	$ 10.71	$ 10.42	$ 10.13	$ 9.86	$ 9.59	$ 9.33	$ 9.08	$ 8.84	$ 8.61	$ 8.38
TOU-PA-2	$ 11.68	$ 11.36	$ 11.05	$ 10.75	$ 10.46	$ 10.18	$ 9.90	$ 9.64	$ 9.39	$ 9.14
TOU-PA-3	$ 11.22	$ 10.91	$ 10.62	$ 10.32	$ 10.04	$ 9.77	$ 9.51	$ 9.25	$ 9.01	$ 8.77
Street Lights	$ 10.56	$ 10.26	$ 9.98	$ 9.70	$ 9.43	$ 9.17	$ 8.92	$ 8.68	$ 8.44	$ 8.22

- Annual load growth is assumed at 0.5%

CAISO costs

- CAISO cost: $1.60/MWh
- Distribution losses: 6%
- Scheduling fees: $0.40/MWh

Other costs

- Data Manager Charges of $1.15 per account per month
- Utility Service Fees of $1.25 per account per month

<u>PG&E Inputs</u>

<u>Annual Rate Growth</u>

- Generation rates (net of PCIA/FFS):

PG&E Generation Annual Average Rates ($/MWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
E-1	$ 87.93	$ 88.50	$ 92.17	$ 95.23	$ 105.32	$ 100.23	$ 103.68	$ 107.57	$ 112.36	$ 118.52
E-7	$ 87.79	$ 88.36	$ 92.03	$ 95.09	$ 105.17	$ 100.09	$ 103.53	$ 107.42	$ 112.21	$ 118.36
A-1	$ 85.94	$ 86.50	$ 90.09	$ 93.08	$ 102.96	$ 97.98	$ 101.35	$ 105.16	$ 109.84	$ 115.87
A-6	$ 102.75	$ 103.25	$ 107.24	$ 110.54	$ 121.73	$ 115.91	$ 119.66	$ 123.91	$ 129.17	$ 135.96
A-10	$ 87.66	$ 88.25	$ 91.95	$ 95.04	$ 105.20	$ 100.10	$ 103.58	$ 107.50	$ 112.32	$ 118.52
E-19-S	$ 81.39	$ 81.93	$ 85.35	$ 88.21	$ 97.61	$ 92.89	$ 96.10	$ 99.73	$ 104.19	$ 109.93
E-19-P	$ 73.27	$ 73.84	$ 77.07	$ 79.77	$ 88.54	$ 84.22	$ 87.25	$ 90.66	$ 94.85	$ 100.21
E-19-T	$ 57.39	$ 58.00	$ 60.86	$ 63.27	$ 70.80	$ 67.27	$ 69.95	$ 72.94	$ 76.58	$ 81.22
E-20-S	$ 76.44	$ 76.96	$ 80.19	$ 82.89	$ 91.76	$ 87.32	$ 90.36	$ 93.78	$ 98.00	$ 103.41
E-20-P	$ 76.33	$ 76.81	$ 79.97	$ 82.61	$ 91.34	$ 86.93	$ 89.90	$ 93.26	$ 97.40	$ 102.71
E-20-T	$ 68.57	$ 69.04	$ 71.93	$ 74.35	$ 82.28	$ 78.30	$ 81.02	$ 84.09	$ 87.86	$ 92.70
TC-1	$ 75.63	$ 76.22	$ 79.57	$ 82.37	$ 91.44	$ 86.97	$ 90.11	$ 93.65	$ 97.98	$ 103.53
Ag	$ 79.61	$ 80.09	$ 83.35	$ 86.07	$ 95.09	$ 90.51	$ 93.57	$ 97.04	$ 101.31	$ 106.80
Street Lights	$ 70.02	$ 70.48	$ 73.41	$ 75.86	$ 83.93	$ 79.87	$ 82.63	$ 85.74	$ 89.57	$ 94.49

- Exit fees (PCIA and franchise fees surcharge):

PCIA and Franchise Fee Surcharge PG&E Average Rates ($/MWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
E-1	$ 30.58	$ 29.66	$ 28.77	$ 27.91	$ 27.07	$ 26.26	$ 25.47	$ 24.71	$ 23.97	$ 23.25
E-7	$ 30.58	$ 29.66	$ 28.77	$ 27.91	$ 27.07	$ 26.26	$ 25.47	$ 24.71	$ 23.97	$ 23.25
A-1	$ 29.93	$ 29.03	$ 28.16	$ 27.32	$ 26.50	$ 25.70	$ 24.93	$ 24.18	$ 23.46	$ 22.75
A-6	$ 29.93	$ 29.03	$ 28.16	$ 27.32	$ 26.50	$ 25.70	$ 24.93	$ 24.18	$ 23.46	$ 22.75
A-10	$ 31.30	$ 30.36	$ 29.45	$ 28.57	$ 27.71	$ 26.88	$ 26.07	$ 25.29	$ 24.53	$ 23.80
E-19-S	$ 28.80	$ 27.94	$ 27.10	$ 26.28	$ 25.50	$ 24.73	$ 23.99	$ 23.27	$ 22.57	$ 21.89
E-19-P	$ 28.80	$ 27.94	$ 27.10	$ 26.28	$ 25.50	$ 24.73	$ 23.99	$ 23.27	$ 22.57	$ 21.89
E-19-T	$ 28.80	$ 27.94	$ 27.10	$ 26.28	$ 25.50	$ 24.73	$ 23.99	$ 23.27	$ 22.57	$ 21.89
E-20-S	$ 27.44	$ 26.62	$ 25.82	$ 25.04	$ 24.29	$ 23.56	$ 22.86	$ 22.17	$ 21.51	$ 20.86
E-20-P	$ 26.16	$ 25.38	$ 24.61	$ 23.88	$ 23.16	$ 22.46	$ 21.79	$ 21.14	$ 20.50	$ 19.89
E-20-T	$ 24.47	$ 23.74	$ 23.02	$ 22.33	$ 21.66	$ 21.01	$ 20.38	$ 19.77	$ 19.18	$ 18.60
TC-1	$ 29.93	$ 29.03	$ 28.16	$ 27.32	$ 26.50	$ 25.70	$ 24.93	$ 24.18	$ 23.46	$ 22.75
Ag	$ 26.52	$ 25.72	$ 24.95	$ 24.20	$ 23.48	$ 22.77	$ 22.09	$ 21.43	$ 20.78	$ 20.16
SL	$ 24.61	$ 23.87	$ 23.16	$ 22.46	$ 21.79	$ 21.13	$ 20.50	$ 19.88	$ 19.29	$ 18.71

- Annual load growth is assumed at 0.5%

<u>CAISO costs</u>

- CAISO cost: $1.60/MWh
- Distribution losses: 6%
- Scheduling fees: $0.40/MWh

<u>Other costs</u>

- Data Manager Charges of $1.15 per account per month
- Utility Service Fees of $0.37 per account per month

[16] Rate projections are based on current rates which are then projected forward consistent with PEA price assumptions and the resource plans published by the IOUs.

Exhibit 2 - Pro Forma Summary

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. Revenue	-	136,673,754	139,991,383	145,508,839	150,681,355	160,851,305	160,464,456	166,135,661	172,201,767	179,000,514	186,876,329	193,478,250
II. Operating Expenses												
Power Supply	-	128,306,495	132,628,112	135,351,263	138,439,450	142,019,490	145,797,478	149,106,080	152,731,761	156,437,792	160,282,680	163,947,185
Staff	500,000	3,075,000	3,151,875	3,230,672	3,311,439	3,394,225	3,479,080	3,566,057	3,655,209	3,746,589	3,840,254	3,936,260
Marketing and Communications	291,219	1,124,404	1,110,563	1,138,635	1,167,417	1,196,928	1,227,187	1,258,213	1,290,025	1,322,642	1,356,087	1,390,378
Legal, Consulting, other Prof. Services	300,000	1,537,500	1,575,938	1,615,336	1,655,719	1,697,112	1,739,540	1,783,029	1,827,604	1,873,294	1,920,127	1,968,130
Data Management	-	1,414,576	1,421,644	1,428,748	1,435,888	1,443,051	1,450,264	1,457,514	1,464,786	1,472,095	1,479,454	1,486,837
Utility Service Fees	-	274,885	265,467	269,818	274,282	278,861	283,563	288,388	293,339	298,422	303,641	308,997
Miscellaneous Admin. & General	83,333	512,500	525,313	538,445	551,906	565,704	579,847	594,343	609,201	624,431	640,042	656,043
Uncollectibles/Other	-	683,369	699,957	727,544	753,407	804,257	802,322	830,678	861,009	895,003	934,382	967,391
Subtotal Operating Expenses	1,174,552	136,928,729	141,378,869	144,300,461	147,589,509	151,399,628	155,359,282	158,884,302	162,732,935	166,670,268	170,756,666	174,661,222
Operating Margin	**(1,174,552)**	**(254,975)**	**(1,387,485)**	**1,208,379**	**3,091,846**	**9,451,677**	**5,105,174**	**7,251,359**	**9,468,833**	**12,330,245**	**16,119,662**	**18,817,028**
III. Financing												
Startup Funding Repayment	37,500	237,500	270,000	270,000	270,000	270,000	270,000	270,000	270,000	270,000	2,732,500	6,532,500
Targeted Reserve Contribution	-	5,466,950	5,599,655	5,820,354	6,027,254	6,434,052	6,418,578	6,645,426	6,888,071	7,160,021	7,475,053	7,739,130
Subtotal Financing	37,500	5,704,450	5,869,655	6,090,354	6,297,254	6,704,052	6,688,578	6,915,426	7,158,071	7,430,021	10,207,553	14,271,630
IV. Total Revenue Requirement	1,212,052	142,633,179	147,248,524	150,390,814	153,886,763	158,103,680	162,047,860	165,799,729	169,891,005	174,100,289	180,964,220	188,932,852
V. Financing Proceeds	2,500,000	6,500,000	-	-	-	-	-	-	-	-	-	-
VI. Actual Reserve Contribution	1,287,948	6,007,525	(1,657,485)	938,379	2,821,846	9,181,677	4,835,174	6,981,359	9,198,833	12,060,245	13,387,162	12,284,528
VII. Cumulative Reserve	1,287,948	7,295,473	5,637,988	6,576,367	9,398,213	18,579,890	23,415,063	30,396,422	39,595,255	51,655,500	65,042,662	77,327,191
VIII. Program Average Rate ($/MWh)	-	71.7	73.1	75.6	77.9	82.7	82.1	84.6	87.2	90.2	93.7	96.5
IX. Power Supply ($/MWh)	-	67.3	69.2	70.3	71.5	73.0	74.6	75.9	77.4	78.8	80.4	81.8
X. Program Average Cost ($/MWh)	-	74.8	76.9	78.1	79.5	81.3	82.9	84.4	86.1	87.8	90.8	94.3
XI. Annual Sales (MWh)	-	1,906,431	1,915,963	1,925,543	1,935,170	1,944,846	1,954,571	1,964,343	1,974,165	1,984,036	1,993,956	2,003,926

Exhibit 3 - Pro Forma Summary – Residential Only Sensitivity

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. Revenue	-	40,702,649	41,847,791	43,411,139	44,920,401	47,368,130	47,865,856	49,499,731	51,218,324	53,084,725	55,163,279	57,017,732
II. Operating Expenses												
Power Supply	-	32,910,851	34,019,007	34,735,541	35,540,902	36,464,989	37,438,024	38,285,709	39,214,066	40,162,996	41,147,328	42,086,178
Staff	300,000	1,845,000	1,891,125	1,938,403	1,986,863	2,036,535	2,087,448	2,139,634	2,193,125	2,247,953	2,304,152	2,361,756
Marketing and Communications	233,907	901,771	889,806	912,304	935,372	959,024	983,276	1,008,143	1,033,639	1,059,782	1,086,588	1,114,073
Legal, Consulting, other Prof. Services	300,000	1,537,500	1,575,938	1,615,336	1,655,719	1,697,112	1,739,540	1,783,029	1,827,604	1,873,294	1,920,127	1,968,130
Data Management	-	1,184,401	1,190,318	1,196,270	1,202,257	1,208,264	1,214,307	1,220,384	1,226,483	1,232,616	1,238,785	1,244,975
Utility Service Fees	-	232,041	221,885	225,478	229,165	232,947	236,829	240,813	244,901	249,097	253,406	257,827
Miscellaneous Admin. & General	50,000	307,500	315,188	323,067	331,144	339,422	347,908	356,606	365,521	374,659	384,025	393,626
Uncollectibles/Other	-	203,513	209,239	217,056	224,602	236,841	239,329	247,499	256,092	265,424	275,816	285,089
Subtotal Operating Expenses	883,907	39,122,579	40,312,505	41,163,455	42,106,024	43,175,135	44,286,661	45,281,816	46,361,431	47,465,822	48,610,227	49,711,654
Operating Margin	**(883,907)**	**1,580,071**	**1,535,285**	**2,247,684**	**2,814,377**	**4,192,995**	**3,579,195**	**4,217,915**	**4,856,892**	**5,618,903**	**6,553,052**	**7,306,078**
III. Financing												
Startup Funding Repayment	37,500	75,000	75,000	75,000	75,000	75,000	75,000	75,000	2,537,500	-	-	-
Targeted Reserve Contribution	-	1,628,106	1,673,912	1,736,446	1,796,816	1,894,725	1,914,634	1,979,989	2,048,733	2,123,389	2,206,531	2,280,709
Subtotal Financing	37,500	1,703,106	1,748,912	1,811,446	1,871,816	1,969,725	1,989,634	2,054,989	4,586,233	2,123,389	2,206,531	2,280,709
IV. Total Revenue Requirement	921,407	40,825,685	42,061,417	42,974,901	43,977,840	45,144,860	46,276,295	47,336,805	50,947,664	49,589,211	50,816,759	51,992,364
V. Financing Proceeds	2,500,000	-	-	-	-	-	-	-	-	-	-	-
VI. Actual Reserve Contribution	1,578,593	1,505,071	1,460,285	2,172,684	2,739,377	4,117,995	3,504,195	4,142,915	2,319,392	5,618,903	6,553,052	7,306,078
VII. Cumulative Reserve	1,578,593	3,083,664	4,543,949	6,716,634	9,456,011	13,574,006	17,078,201	21,221,116	23,540,508	29,159,412	35,712,464	43,018,542
VIII. Program Average Rate ($/MWh)	-	83.3	85.3	88.0	90.6	95.1	95.6	98.4	101.3	104.4	108.0	111.1
IX. Power Supply ($/MWh)	-	67.4	69.3	70.4	71.7	73.2	74.8	76.1	77.5	79.0	80.6	82.0
X. Program Average Cost ($/MWh)	-	83.6	85.7	87.1	88.7	90.6	92.4	94.1	100.7	97.6	99.5	101.3
XI. Annual Sales (MWh)	-	488,370	490,811	493,266	495,732	498,211	500,702	503,205	505,721	508,250	510,791	513,345