Community Choice Aggregation

Base Case Feasibility Evaluation

City of Emeryville

Prepared By Navigant Consulting, Inc

March 2005

EXECUTIVE SUMMARY

This report offers Navigant Consulting, Inc.'s (NCI) evaluation of the feasibility of forming a Community Choice Aggregation program, pursuant to provisions of Assembly Bill 117, whereby the City would aggregate the electric loads of customers within its jurisdiction for purposes of procuring electrical services. Community Choice Aggregation relates to electric generation services only. Delivery of the electric power would continue to be provided over PG&E transmission and distribution facilities at rates regulated by the California Public Utilities Commission (CPUC) and under the same terms and conditions that apply today. Community Choice Aggregation allows the City to provide retail generation services to customers without the need to acquire transmission and distribution infrastructure. All PG&E customers within the City would have the option of buying electricity from the City or, alternatively, remaining as generation customers of PG&E by exercising their rights to opt-out of the program.

AB 117 grants the City authority to competitively procure electric services rather than continuing to rely on PG&E as the single supplier for electric services provided to customers within the City. Implementation of Community Choice Aggregation provides the community the power to choose what resources will serve their loads. Expanded access to competitive suppliers and local control of resource planning decisions provides opportunities to enhance rate stability for customers, significantly increase utilization of renewable energy resources, and generate electricity cost savings.

The detailed analysis performed for the City suggests that by forming a Community Choice Aggregation program, backed by investments in generation resources, the City could:

- Achieve nominal electricity cost savings averaging over $3.7 million per year, equivalent to approximately 10% of total electricity bills;
- Increase renewable energy utilization to 50% by 2017, more than doubling the renewable energy content that PG&E would provide over the same time period; and
- Obtain control over electric generation costs to provide a higher level of rate stability for local residents and businesses.

The scenario analysis shows that the existence of cost savings is not dependent upon the specific financial assumptions underlying the base case feasibility assessment but is primarily dependent upon the supply portfolio developed for the program. The average program savings range from a low of 3% to a high of 23% across the eight scenarios evaluated to test the sensitivity of these results to changes in wholesale energy market conditions, PG&E rate projections, and cost responsibility surcharges. Although the City could implement a CCA program without investing in generation resources, such a strategy is unlikely to yield sustainable electricity cost savings over the long term. NCI recommends a phased approach to implementation that includes initially purchasing all of the program's electric supply requirements on the open market and transitioning to a strategy of generating the bulk of the program's resource needs through community-owned generation.

The conclusions and recommendations of this study took into consideration the City's known interests and objectives. The study reflects substantial involvement of City staff, both individually and through a series of discussions with other local governments participating in the project. Various portfolio options were evaluated in terms of their effectiveness in meeting the objectives and interests of the community. Following detailed review of the options, a preferred portfolio option was jointly developed with staff that would best satisfy the stated objectives and interests of the City.

This report and supporting analysis show that it would be feasible and economically viable for the City to implement a Community Choice Aggregation program as early as 2006. Whereas all current CPUC decisions are reflected in the feasibility assessment, the CPUC is still in the process of finalizing certain detailed rules and protocols that will apply to Community Choice Aggregation. The ongoing phase of the CPUC rulemaking is focused on operations and transactional issues that will be important to a Community Choice Aggregation program's operations but that are unlikely to materially impact the base case feasibility assessment presented herein.

Energy procurement and resource planning are subject to certain risks or uncertainties that must be managed by the energy supplier, whether it is PG&E or the operator of a Community Choice Aggregation program. Forming a Community Choice Aggregation program would not increase operational risks, but responsibility for their management would transfer to the Community Choice Aggregator and/or its suppliers. The City will be able to obtain services from a variety of large, experienced suppliers to help manage the Community Choice Aggregation program. It would therefore be able to manage energy procurement risks at least as effectively as does PG&E. Professional program management and application of standard industry risk management practices will be keys to this effort.

The City can phase-in implementation of Community Choice Aggregation to help ensure a smooth transition for customers that join the program. Although the program's financial viability is not dependent upon a phased implementation, a phase-in would reduce implementation risk and would contribute to the program's financial benefits during the initial startup stage.

NCI recommends that the City implement its Community Choice Aggregation program through formation of a joint powers agency (JPA) with other local governments in Northern California that are also participants in the Community Choice Aggregation Demonstration Project. Formation of a regional program through the JPA provides economies of scale that enhance the economic benefits available to the City through Community Choice Aggregation. The JPA structure provides an appropriate financing vehicle for the capital investments needed to support a cost-effective aggregation program.

LIST OF ACRONYMS

A&G – Administrative and General
AB 1890 – Assembly Bill 1890
AB 117 – Assembly Bill 117
CAISO – California Independent System Operator
CCA – Community Choice Aggregation
CEC – California Energy Commission
CPUC – California Public Utilities Commission
CRS – Cost Responsibility Surcharge
CTC – Competition Transition Charge
DG – Distributed Generation
DWR – Department of Water Resources
FERC – Federal Energy Regulatory Commission
GRC – General Rate Case
IOU – Investor Owned Utilities
IT – Information Technology
JPA – Joint Powers Agency
KW - Kilowatt
KWh – Kilowatt hour
MW – Megawatt
MWh – Megawatt hour
NOPEC – Northern Ohio Public Energy Council
NOx – Nitrogen Oxides
NP15 – North of Path 15
O&M – Operations and Maintenance
PG&E – Pacific Gas and Electric Company
PTC – Production Tax Credit
PUC – Public Utilities Code
PUCO – Public Utilities Commission of Ohio
PV - Photovoltaic
QF – Qualifying Facilities
RE – Renewable Energy
REC – Renewable Energy Certificate
RPS – Renewable Portfolio Standard
RRDR – Renewable Resource Development Report
SCE – Southern California Edison Company
SDG&E – San Diego Gas and Electric Company
SEP – Supplemental Energy Payment
VEE – Verification, Editing and Estimation

TABLE OF CONTENTS

1 INTRODUCTION

1.1 Objective

The City is a participant in the Community Choice Aggregation Demonstration Project, which was commissioned by the California Energy Commission (CEC) and the United States Department of Energy to assist local governments in evaluating and implementing Community Choice Aggregation, whereby the City would aggregate the electric loads of customers within the City for purposes of procuring electrical services.

The purpose of this report is to evaluate the feasibility of the City forming a Community Choice Aggregation Program. The report contains detailed economic feasibility analyses and recommendations to help the community evaluate the costs and benefits afforded by Community Choice Aggregation and move towards development of an Implementation Plan.

The report and analyses contained herein comprise project deliverable Task 4: Load Analysis and CPUC Decision Based Feasibility Analysis. This report builds upon the Load Analysis and Assumptions Based Feasibility Analysis previously provided to the City, which presented economic feasibility results for a CCA program utilizing four alternative supply portfolios. Upon review of the preliminary results, the City provided input on its preferred supply portfolios with respect to the percentage of its supply it desires to be produced from renewable energy resources and whether the City intends to utilize its municipal financing capabilities to reduce the costs of is electricity procurement program by financing energy development projects. These supply preferences and other feedback received from the City staff are reflected in this final report. This report additionally incorporates the CPUC's December 16, 2004 decision in Phase 1 of the CCA rulemaking (Decision No. D.04-12-046).

As second phase of the Demonstration Project will include the development of a template for use by communities in developing Implementation Plans for submission to the California Public Utilities Commission (CPUC). Communities can utilize the template to help them develop their Implementation Plans.

1.2 Project Elements And Timeline

NCI recommends a two-phased approach for consideration of forming a CCA program. Phase 1 includes the base case feasibility study and report, while Phase 2 includes development of an Implementation Plan for submittal to the CPUC. A high level overview of these phases is shown below:

Phase 1 Element	Timeline
Community Selection	Complete
Participant Orientation	Complete
Renewable Resources Workshop	Complete
Base Case Feasibility Analysis	Complete
Participation in CPUC CCA Rulemaking Phase 1	Complete
Draft Evaluation and Report	Complete
Final Feasibility Analysis	March 2005
Final Evaluation and Report	March 2005

Phase 2 Element	
Development of Implementation Plan Template	Ongoing
Participation in CPUC CCA Rulemaking Phase 2	Jan. 2005 – Jun. 2005
Prepare and Submit Implementation Plan	Summer 2005
Support Implementation Plan Filing At CPUC	Summer 2005

1.3 Phase 2 - Implementation Plan

After considering the expected benefits and costs of forming a CCA program, communities that wish to proceed with forming a CCA program will need to develop an Implementation Plan. AB 117 requires submission of an Implementation Plan to the CPUC prior to the CCA commencing operations. The law requires the Implementation Plan to "detail the process and consequences of aggregation." The Implementation Plan and subsequent changes to it must be adopted at a duly noticed public hearing. The Implementation Plan must contain all of the following:

- An organizational structure of the program, its operations, and its funding.
- Ratesetting and other costs to participants;
- Provisions for disclosure and due process in setting rates and allocating costs among participants;
- The methods for entering and terminating agreements with other entities;
- The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures;
- Termination of the program; and
- A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

A CCA must prepare a statement of intent with the Implementation Plan. Any CCA program shall provide for the following:

- Universal access
- Reliability
- Equitable treatment of all classes of customers
- Any requirements established by state law or by the CPUC concerning aggregated service

The California Public Utilities Commission has responsibility to review the Implementation Plan submitted by an Aggregator, and it may establish additional detail regarding the form and content of an Implementation Plan in Phase 2 of R.03-10-003.

2 OVERVIEW OF CCA

2.1 What Is CCA?

Assembly Bill 117 permits California cities, counties, or city and county joint powers agencies ("local governments"), to implement a program to aggregate the electric loads of electric service customers within their jurisdictional boundaries to facilitate the purchase and sale of electricity. The local government would become a Community Choice Aggregator ("Aggregator") to procure electric energy for residents and businesses within a community. All customers currently receiving electric generation services from PG&E would be automatically enrolled in the program, unless the customer notifies the City of its desire to opt-out and remain a bundled service customer of PG&E. The City would be responsible for operating the CCA program, either by performing the functions necessary for program operations utilizing its own employees or by contracting out operations to one or more third-party operators or energy services providers.

Within the context of CCA, "*electricity*" means the electric energy commodity only. CCA's enabling legislation requires local utilities such as PG&E to provide electricity delivery over its existing distribution system and provide end-consumer metering, billing, collection and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). Accordingly, the infrastructure requirements of the CCA program do not include any electric transmission or distribution related facilities to serve CCA retail loads. PG&E must provide delivery services to CCA customers under the same terms and conditions as provided to other of its customers.

It is important to distinguish an Aggregator from municipal utilities and from energy service providers as each of these entities provides different services, has different responsibilities, and operates under different regulatory frameworks. A local government that implements a community choice aggregation program does not become a municipal utility in the manner of the Los Angeles Department of Water and Power or the Sacramento Municipal Utility District, which own and operate transmission and distribution systems. A critical distinguishing factor is that the City would not own the electric distribution system within the City. Rather, it would own or procure electric power from the wholesale markets, either through ownership of resources, market purchases, or through a partner on behalf of the customers that choose to aggregate their loads. The local investor owned utility (PG&E, SCE, or SDG&E) would then be required to deliver the electric energy to the end-use customer across its transmission and distribution facilities. In this sense, an Aggregator is similar to an electricity service provider that sells electricity to direct access customers. However, there are important differences between CCA and direct access, and these two programs will operate under different sets of rules established by the CPUC.

Customers of the CCA will pay the same charges for delivery (transmission and distribution) as customers that remain as full service, "bundled" customers of PG&E. These delivery charges represent approximately one half of the typical household's monthly electric bill. The City will establish rates for the generation services it provides to CCA customers, and these customers will no longer pay PG&E for generation services. However, PG&E will be authorized to assess a surcharge for certain of its generation related costs that might otherwise be shifted to its remaining bundled service customers. This surcharge is known as the "cost responsibility surcharge" or "CRS", and it will be regulated by the CPUC. The cost responsibility surcharge is discussed in greater detail in Section 5.3.2.

By law, PG&E will perform all metering and billing for CCA customers. PG&E will collect the City's charges from CCA customers and transfer the funds collected to the City in the monthly billing process. To a large extent PG&E's costs of providing metering, billing and customer services are included in their existing delivery charges. However, the utilities have asserted that CCA programs will cause additional costs related to metering, billing and customer services, and they have requested the CPUC to authorize additional charges to be assessed on Aggregators or CCA customers. This and other issues in the CPUC Rulemaking are discussed in Section 2.5.

2.2 Legal And Regulatory Authority

A CCA program for electric customers is governed by the Community Choice Aggregation legislation (AB 117, Chapter 838, September 24, 2002[1]). A local government could become an Aggregator for electric utility generation by developing an Implementation Plan, and then having this plan approved by the CPUC. AB 117 offers flexibility in that it is an "opt-out" program rather than an "opt-in" program. This would allow the City to sign up customers willing to switch from PG&E generation service to CCA service without the necessity of developing an active marketing effort to lure customers. Instead, the City would merely need to notify customers of the impending Community Choice Aggregation program. Any customers that do not want to participate in the program would be required to notify the City of their election to opt-out within a specified amount of time.

---

[1] AB 117 became effective January 1, 2003 amends Sections 218.3, 366, 394, and 394.25 of the Public Utilities Code and creates Sections 331.1, 366.2, and 381.1 to the same Code.

AB 117 also requires full cooperation by the host investor owned utility in any CCA program implemented by the City. In this regard, AB 117 would require PG&E to provide necessary load information and other important data and continue to provide transmission, distribution, metering, meter reading, billing and other essential customer services.

2.2.1 Requirements After Filing The Implementation Plan

1. Within 10 days after the Implementation Plan is filed, the CPUC will notify PG&E (PUC Section 366.2(c)(6)).

2. Within 90 days after the City files an Implementation Plan the CPUC shall certify that it has received the Implementation plan, including any additional information necessary to determine a cost recovery mechanism. The Commission shall designate the earliest possible date for implementation of a CCA program (PUC Section 366.2(c)(7)).

3. The City must offer the opportunity to purchase electricity to all residential customers within its political boundaries (PUC Section 266.2(b))

4. PG&E shall fully cooperate with the City, including providing appropriate billing, and electrical load data, in accordance with CPUC procedures (PUC Section 366.2(c)(9))

5. The City must fully inform all customers of their right to opt-out of the CCA program and to continue to receive service as a bundled customer from PG&E. All customers must be notified twice within two months or 60 days prior to the date of automatic enrollment. In addition, notification must continue for participating customers for at least two consecutive billing cycles after enrollment (PUC Section 366.2(c)(11),(13).

6. Notification must contain the following information:
   - Customer will be automatically enrolled
   - Each customer has the right to opt-out of the program without penalty
   - The terms and conditions of CCA service (PUC Section 366.2(13)(A))

7. The City may request the Commission to approve and order PG&E to provide the customer notifications (PUC Section 366.2(13)(B)).

8. The City must register with the CPUC and may be required to provide additional information in order to verify compliance with rules for consumer protection and other procedures (PUC 366.2(c)(14)). At the time of registration, the City must post a bond or provide evidence of sufficient

insurance to cover any reentry fees that may be imposed against it by the CPUC for involuntarily returning a customer to service of PG&E (PUC Section 394.25(e)).

9. The City must notify PG&E that CCA service will begin within 30 days (PUC Section 366.2(c)(15)).

10. Once notified, PG&E shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process (PUC Section 366.2(c)(16)).

11. PG&E shall recover from the City any costs reasonably attributable to the City, as determined by the CPUC (PUC Section 366.2(c)(17)).

2.3 Status Of CPUC Rulemaking

While AB 117 does provide a statutory basis for Community Aggregation projects, the CPUC has not yet developed and implemented final rules for the development of such programs. On September 4, 2003, the CPUC issued an order instituting a rulemaking or "OIR" (Rulemaking 03-09-007) in order to develop the guidelines for community aggregation programs, as it was directed to do under AB 117. On October 2, 2003, the CPUC reissued the rulemaking under Docket No. R.03-10-003. The CPUC bifurcated the proceeding into two phases. The scope of Phase 1 is to determine issues related to costs imposed by the local utilities on Aggregators and CCA customers, namely cost responsibility surcharges, transaction fees, and implementation costs. The general scope of Phase 2 is to address the processes for interactions between Aggregators and the local utilities and other operational details. The issues identified with each phase are listed below:

2.3.1 Phase 1 Issues

- Cost responsibility surcharges – methodology, transparency, caps, new utility procurement, rate design, phasing, assumption of in lieu MWh
- Transactions costs - implementation fees, fees related to CCA establishment, enrollment fees, billing, payment and collection, monthly account maintenance fee, interval metering fee, termination of CCA program fee, special request fee, information fees
- Customer information issues – data needs of Aggregators, customer confidentiality protections

2.3.2 Phase 2 Issues

- The detailed processes, costs, and fees authorized for the utilities' CCA implementation activities and utility transactions with CCAs (e.g., metering, billing, CCA establishment, notifications, enrollments, account maintenance, termination)
- Rules and formats for notifying customers of CCA service and customer opt-out opportunities
- Rules for switching customers to CCA service, processing customer opt-outs, and returning CCA customers to utility service
- Customer reentry fees and bonding requirements imposed on CCAs
- CCA phase-in mechanisms and guidelines
- CCA consumer protection obligations
- CCA Implementation Plan requirements

The Commission issued its final decision (D.04-12-046) in Phase 1 on December 16, 2004. The schedule for Phase 2 has not yet been established, but it is expected to conclude in the second or third quarter of 2005.

2.4 Aggregation In Other States

Aggregation programs exist in both Massachusetts and Ohio, with the Ohio program being most similar to Community Choice Aggregation in California. Ohio includes provisions for government aggregation on an opt-in or opt-out basis. According to the Public Utilities Commission of Ohio (PUCO), Ohio has had among the most successful electric choice programs in the nation, with government aggregation leading the way.[2] The greatest success is in those areas of Ohio that have adopted aggregation. Northern Ohio has enjoyed a high rate of customer switching due in large part to this process whereby communities band together to buy electricity, in bulk, for their residents. In the first two years of electric choice:

- More than 150 local governments passed ballot issues and were certified by the PUCO to allow local units of government to represent their communities in the competitive electricity market. Ohio is home to the Northeast Ohio Public Energy Council (NOPEC), the largest public aggregator in the United States. NOPEC represents 112 communities in eight counties and more than 350,000 residential customers.

[2] Information about the Ohio aggregation experience was obtained from The Ohio Retail Electric Choice Programs Report of Market Activity 2001-2002, A Report by The Public Utilities Commission of Ohio, May 2003.

Of those customers who have switched in Ohio, aggregation programs account for:

- Nearly 93% of residential customers who have switched in Ohio
- More than 88% of commercial customers who have switched in Ohio
- Nearly 20% of industrial customers who have switched in Ohio

2.5 Implementation Models

There are a variety of approaches the City could take in implementing a CCA program, varying in the degree of operational control, risk and benefits afforded to the City.

2.5.1 Single Third Party Supplier

At one end of the spectrum, the City could pursue a minimalist approach, essentially serving as a conduit between electric customers within the City and a third party electric supplier. The City would solicit offers from electric suppliers to serve the customers that choose to participate in the program (i.e., do not opt out) and would largely rely on the supplier to administer the program. An example would be for the City to negotiate a guaranteed discount to the prevailing PG&E rate such that the supplier absorbs the risks of meeting the obligation to provide electricity cost savings. This approach offers very little risk to the City but also limits the potential upside, especially with respect to the benefits offered by municipal-financed generation assets or financing arrangements.[3] Suppliers may not be willing to absorb the risks associated with factors that are outside the control of the supplier, such as those posed by changes in PG&E rates or the CRS. Furthermore, under the assumption that suppliers would not charge less than the market price of electricity as utilized in this analysis, the imposition of the CRS would appear to eliminate the opportunity for cost savings to be obtained in the near term. Indicative bids from electricity suppliers should be obtained early in the City's implementation planning to help determine whether this approach is financially viable.

2.5.2 Multiple Third Party Service Providers

In pursuing this approach, the City would "unbundle" the electric services needed for the program and negotiate contracts with third parties for provision of these discrete services (e.g., billing services, scheduling coordination, electric supply). The City would assume overall responsibility for the program and for

[3] It may be possible to negotiate agreements with the electric supplier to integrate municipal resources or utilize municipal bonding, but this would necessitate greater City involvement than represented by the pure minimalist approach outlined here.

the performance of its contractors. The City would be responsible for setting rates and program policies and for general administration of the program. This approach offers several advantages, including limited staffing requirements, greater control, diffusion of risk (associated with supplier default), and the accumulation of industry knowledge and experience that creates strategic value at the City. Under this approach, the City would bear sole accountability for the results achieved by the program; regardless of whether these are successes or failures.

2.5.3 Municipal Operations

In the longer term, the City could create the organization needed to operate the CCA program, utilizing in-house staff and resources. Recruiting skilled professional staff with electricity operations experience would be a challenging endeavor in the near term and is probably not feasible for a planned 2006 start date. Over time, as the City gains experience with the program, some or all functions that were initially contracted out to third parties could be brought in-house, if desired.

2.5.4 Unilateral or Joint Operations

The City could implement a CCA program on its own or in combination with other cities and/or counties through a Joint Powers Agency (JPA). Clearly, there would be efficiencies and cost savings achieved by jointly implementing a single program. Such a combined program provides scale economies, improving terms of financing and power supply options. Customers would get the benefits of greater bulk buying power and professional expertise available through a larger organization. A larger organization would wield greater political influence and more effectively participate in the regulatory process to protect member interests. Individual implementation would require a greater investment of time and expense by the City, and would entail generally higher operations costs. A common program also removes some of the risk in making the decision to offer aggregation services to customers because the City would not be proceeding alone.

The primary disadvantage of implementation through a JPA is a joint program could reduce the degree of autonomy exercised by the City over its program.

While this report is premised on the City implementing a CCA program independent of other local governments, it also includes a pro forma analysis of a joint CCA program, in combination with other local government participants in the Demonstration Project. NCI recommends the City pursue forming a JPA to operate a regional CCA program, which would offer the maximum benefits to its members.

3 BENEFITS OF CCA

The primary benefits offered by CCA are local control over the energy resources utilized by the community and the ability to provide electricity to customers at a lower overall cost. The cost savings can accrue to customers through lower electric bills or can be used by the City to provide enhanced services to its constituents. Local control manifests in a variety of benefits giving customers a means to effectuate their preferences regarding the type of electricity production they support as well as obtaining energy services that satisfy their unique needs. Through CCA, the City can choose to structure a supply portfolio that achieves cost efficiencies, fuel and technological diversity, environmental improvement, and/or cost stability. The City can choose to develop its own energy resources and decide which type of resources will be developed and where such resources should be located, consistent with its general planning responsibilities.

CCA would facilitate the City's implementation of an aggressive program to increase utilization of renewable energy resources and promote improved energy efficiency. The City's local perspective and its primary mission to serve its customers rather than maximize profits for shareholders places it in a unique position to integrate effective demand-side energy efficiency programs with procurement of electricity supplies to lower overall energy costs for the community.

Generally speaking, the cost competitiveness of the CCA program will depend on the following factors:

- The mix of customers served by the City and the rate designs charged by PG&E for the various customer classes
- The composite load profiles (hour-by-hour energy consumptions) of the City's customer portfolio
- The resource mix utilized by the City
- The use of low cost municipal bonds to finance generation resource projects
- Electricity prices and prices for other services negotiated with third party electric suppliers
- The trajectory of PG&E's generation costs and whether all cost increases are passed on to CCA customers through the cost responsibility surcharge
- The costs charged by PG&E for implementation activities and transactions such as metering, billing, and customer services.

A CCA program would enable the City to capture the benefits of competition among suppliers for the right to serve the community's load. California's experience with direct access showed that suppliers were willing to offer discounts to large customers of the investor owned utilities (IOUs). For the most part, discounted rates were not offered to residential customers because of their relatively small loads and the high marketing and transactions costs related to serving mass-market customers. Some suppliers were able to charge higher prices than the IOU's for renewable or "green" energy, and most residential customers that switched to direct access did so to increase the amount of renewable energy used to supply their homes. The opt-out feature of CCA eliminates most of the marketing and transactions costs that limited the opportunities in the direct access market for residential and small commercial customers. Through community aggregation, small customers can obtain competitive electricity supplies directly from the wholesale market on a scale that was simply not feasible under direct access rules.

3.1.1 Lower Electricity Costs

To the extent the City can obtain electricity at a lower cost than charged by PG&E, the margin can be used to lower rates for CCA customers, contribute to reserve or contingency funds, or augment the City's revenues for provision of public services to its constituents.

A comparison of PG&E's rates to current market prices for electricity indicates the margin embedded in the generation rates charged by PG&E. The table below compares the current system average generation rate for PG&E to the estimated cost of supplying the City at current market prices of electricity.

Cost	Cents Per KWh
PG&E Avg. Generation Rate	7.6
Estimated Supply Cost	5.6
Gross Margin	2.0

Absent the imposition of a CRS, the City could capture up to 2.0 cents per kWh of margin by procuring electricity at market prices to supply the program. However, AB 117 and ensuing CPUC rules authorize PG&E to impose surcharges on customers of the CCA that are designed to shield PG&E and its remaining customers from the costs of losing customers to the CCA. The surcharge represents the difference, on a system average basis, of the average cost of PG&E's supply portfolio and the market price of electricity. Conceptually, the imposition of the CRS on CCA customers means the City must obtain electricity supplies at below market prices if it is to provide electricity cost savings to its customers during the time period that the CRS applies.

There are essentially two ways the City could obtain below-market electricity prices: 1) the City could negotiate for low cost electric supplies from third party providers, some of whom may be willing to offer discounted prices in order to gain market share and position their firms for sales of other value added services; or 2) the City could utilize its ability to issue low cost municipal bonds to develop or contract for generation resources. Whereas the opportunity for negotiation of low cost supplies would be circumstantial and ultimately may not materialize, the City's financing advantage offers a clear and lasting competitive advantage.[4] The City, being a public agency, can finance generation projects at an effective cost of capital that is approximately one half of PG&E's or the typical merchant generation developer's. As described in greater detail in Section 6.3.2, the municipal financing advantage is particularly well-suited to development of renewable generation projects, with their relatively high capital costs and low operating costs. By financing generation resources (conventional or renewable) or providing capital to prepay for electricity purchases, the City can obtain electricity at below market costs.

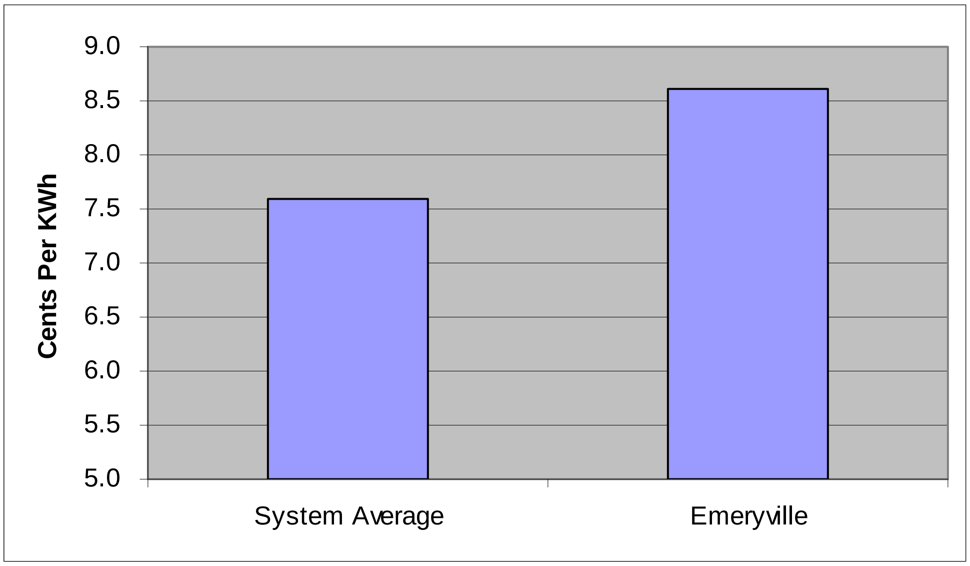
Once the CRS terminates at some point in the future, the City will compete against PG&E's then current supply portfolio, and PG&E will no longer have the protection afforded by the CRS. By 2013, approximately 40% of the PG&E supply portfolio will be comprised of power purchase contracts executed after 2005. Therefore, the cost competitiveness of PG&E's portfolio in the post CRS timeframe will largely depend upon how efficiently PG&E procures electricity supplies during the next several years. The conservative assumption would be that PG&E will procure electricity at prevailing market prices and that the City will need to bring its financing advantages to bear in order to obtain electricity cost savings in the post CRS period.

While conceptually, the imposition of the CRS eliminates cost savings opportunities except to the extent the City can procure electricity at below-market prices, in practice the customer mix of the City's program is an important determinant of whether cost savings opportunities exist due to the presence of cross customer subsidies in PG&E's rate structure. The CRS is calculated as if the City served a mix of customers identical the overall mix of customers on PG&E's system. The actual customer mix within the City is more heavily weighted towards commercial and industrial customers, which subsidize the residential customer class under PG&E's current rate structure. The average generation rates paid to PG&E by customers within the City are approximately 13% higher than the average of all customers within PG&E's service territory, as shown in the chart below:

[4] For the financial analysis contained in this feasibility analysis it is assumed that third party electric suppliers would offer electricity at the full market price of electricity and would not offer discounts.

Current PG&E Generation Rates[5]

System Average Vs. City Of Emeryville



The residential rate subsidies are not reflected in the CRS; i.e. the CRS is the same per kWh rate for all customers. Therefore, these subsidies raise the benchmark PG&E rate against which the City's rates are compared, improving the financial feasibility of implementing a CCA program.[6]

3.1.2 Fuel Efficiency and Environmental Benefits

By implementing a CCA program, the City can cause new generation to be developed, either by offering contracts to suppliers for the purchase of energy or by direct involvement in developing new resources. Development of new generation, whether renewable or fossil fueled, will displace production from old, inefficient generation sources, which can significantly reduce environmental impacts of electricity production. According to the CEC, approximately one third of natural gas consumption in California derives from production of electricity. Today's natural gas-fired generation units can operate 30% to 40% more efficiently than the 1960's era generators that are currently online in California. For every kWh produced from a new generation resource, there

[5] Includes Electric Energy Commodity Component (EECC), Competition Transition Charge (CTC) and DWR Bond Charge.

[6] PG&E's proposals in its 2003 General Rate Case that would reduce interclass subsidies are addressed in the sensitivity analysis presented in Section 6.2.

would be up to 40% less natural gas consumption and even greater reductions in air emissions and greenhouse gases.

A benefit that is particularly important to some communities is the ability to promote use of renewable energy resources and significantly exceed the renewable energy standards applicable to PG&E. Increased renewable generation would reduce air pollution and emissions of greenhouse gases and reduce dependence on natural gas consumption even further. For the same kWh produced by renewable energy resources, natural gas consumption would drop to zero and, depending on the renewable technology employed, air emissions could also be eliminated.

3.1.3 Rate Stability

CCA enables the City to lock in electricity prices and provide multi-year rate stability to its customers. Business customers in particular tend to value predictability in their energy costs to aid in business planning. Rate stability can be an attractive feature to help lure new businesses into the community or retain those that may be considering leaving due to high and unstable electricity costs. CCA allows the community to negotiate for long-term, fixed priced electric supplies from a variety of suppliers. Likewise, increased reliance on renewable energy technologies reduces exposure to the volatile natural gas market, which in turn is a primary driver of electricity price volatility.

Historically, PG&E's rates have exhibited periods of relative stability punctuated by periods of high rates during times of crisis or the addition of major generation investments. Due to actions taken in response to the energy crisis of 2000-2001, PG&E’s current supply portfolio is much more heavily weighted toward fixed price contracts and renewable energy contracts than in the years immediately preceding the energy crisis, and should be expected to deliver relatively stable (but increasing) costs over the next several years. However, PG&E is not free to operate in the market in the most efficient manner and must make procurement decisions within the regulatory context in which it operates. To a large extent, PG&E does not control its own destiny the way an Aggregator can.

The City would possess autonomy over its electricity procurement decisions and the rates it charges to customers, which provides more control over its costs and greater flexibility in its rate structures than PG&E is allowed under CPUC regulation. More tools are available to the City to control its electric supply costs and rates. For example, publicly owned (i.e., municipal) utilities commonly create rate stabilization funds using retained margins that enable the utility to weather short-term cost increases without the need to increase rates. In contrast, PG&E cannot execute supply contracts or build new generation resources without CPUC approval, nor can it establish or modify its rates or reserve accounts without express approval from the CPUC. The regulatory approval process can take many months, and the CPUC may in the end deny the utility's requested authorization. Put simply, the City has more autonomy in its operations than does PG&E, which enhances the City's ability to provide rate stability to its customers.

New generation is needed to serve California's increasing population and to replace thousands of megawatts of aging power plants that will be retired in the next several years. California is entering a period of major electricity infrastructure investments, and the addition of new utility-owned generation will place upward pressure on PG&E's rates, contributing to future rate instability. By assuming the responsibility for developing the infrastructure needed to serve the City's constituents, the City can shield its constituents from future rate increases caused by PG&E generation investments.

3.1.4 Energy Security

As the majority of new power plants in the United States are fueled by natural gas, the nation is increasingly becoming dependent upon imported natural gas. The flurry of activity related to construction of new liquefied natural gas terminals (LNG) along the California and Baja California coast attests to the increased demand for imported natural gas. Many people are concerned that during the next ten to twenty years the United States will become as dependent on natural gas imports as it currently has become on imported oil. Such dependence raises a host of political, environmental and security issues that potentially threaten the nation's vital interests. By implementing a CCA program that relies more heavily on renewable energy resources, the City can ensure that the electricity consumption of customers participating in the program does not contribute to the problems associated with increased dependence on imported natural gas.

3.1.5 Customer Choice

CCA provides choice to all electricity customers because all customers have the option of being automatically enrolled in the CCA program or of remaining with PG&E for provision of generation services. Direct access has been "suspended" by the California legislature, and presently CCA is the only mechanism that allows customers to buy electricity from an entity other than PG&E. All customers can benefit from opportunities for choice and the disciplinary effects of competition on PG&E's service even if they do not take advantage of the CCA program.

3.1.6 Demand Side Energy Efficiency

A CCA program would provide an organizational structure to support administration of energy efficiency programs, and it would also enable seamless integration of energy efficiency into the resource planning process of the City. Energy efficiency or demand side management programs can be tailored to the unique needs of the community and can be integrated with the supply planning of the Aggregator, yielding overall lower supply costs. The City's rates can provide the revenue bonding capacity to finance worthy public benefits programs such as installation of rooftop photovoltaic systems and energy efficiency investments, with debt service provided via monthly customer bills. The City's knowledge of the community can help improve the effectiveness of energy efficiency investments, as the City would be in a better position to identify high potential energy efficiency opportunities in the community.

Local governments should also have strong motivation to deploy effective energy efficiency programs. Investor-owned utilities, such as PG&E, face an inherent conflict of interest in administering energy efficiency programs because the success of their programs reduces the utilities' sales growth and potentially their profitability. As an Aggregator, the City would be motivated to reduce overall energy costs, both on the supply and demand side. An integrated approach to supply planning, energy efficiency and demand response, which reflects the specific circumstances of the community, should translate into greater energy savings.

AB 117 requires that a proportional share of energy efficiency funding be spent in the City if it forms a CCA program. Thus, formation of a CCA program would obligate PG&E to ensure that the City is not under-served by current energy efficiency programs administered by PG&E or third party administrators. The City could seek authority to replace PG&E as administrator of energy efficiency programs by submitting a program application to the CPUC. However, current CPUC rules do not grant Aggregators special rights regarding access to public goods funding for purposes of administering energy efficiency programs. This issue may be reevaluated in Phase 2 of the CCA rulemaking (R.03-10-003).

3.1.7 Self Generation And Wheeling

A CCA program would provide a legal mechanism to transmit excess power from generation located "behind-the-meter" to other loads within the City. For example, excess production from a City cogeneration or solar facility could be used to serve other facilities rather than being sold to PG&E or lost to the system.

The CCA program could enable the City to obtain greater value for its distributed generation facilities.[7]

3.1.8 Regional Economic Competitiveness

The City could use its ratemaking authority to establish economic development and business attraction rates to help lure desirable businesses and jobs to the community with the benefit of lower rates. Competitive electric rates can also be a factor in retaining businesses that might otherwise leave the community, seeking locations with lower costs of doing business. A CCA program that provides low and stable rates can be an important factor in maintaining regional economic competitiveness.

To the extent the City initiates development of local generation resources to serve the CCA program, the reliability of the local area would be enhanced.

3.1.9 Creation of Strategic/Asset Value

Formation of a CCA program creates strategic value arising from the creation of assets, infrastructure and annual cash flows. The City would be developing expertise in energy matters, building infrastructure, and positioning itself for an expanded role in the provision of energy services if future circumstances warrant such an expanded role.

3.1.10 Opportunities For Innovation

A CCA program presents opportunities for the City to provide innovative energy services to customers. The City could develop programs that respond to the local concerns, needs, and values of their community members. One example would be formation of "green pricing" programs that provide customers the option of choosing to use more renewable energy. Customers that value renewable energy would be able to voluntarily pay for any additional costs of increasing the renewable energy mix, reducing the costs to be paid by more price sensitive customers. Other innovative services could include special rates for population subgroups (e.g., low income, government facilities, enterprise zones, etc.), program-financed distributed generation, or a host of other value-added services.

[7] Whether greater value can be achieved in practice would depend upon whether an existing contract is in place governing the sale of excess power from the facility and upon the pricing terms and conditions of the contract.

4 RISK ASSESSMENT

The risks of forming a CCA program evolve as the City begins its implementation planning process and then progresses to startup of program operations. The City's risk exposure also depends greatly upon the implementation approach utilized by the City, as previously discussed in section 2.5.

The major risk associated with forming a CCA program is the possibility that the rates of the program exceed the comparable rates charged by PG&E, causing customers to become dissatisfied with the program or attempt to return to PG&E service. The City's ratemaking authority and ability to raise rates if necessary would protect the City from the financial impacts of unanticipated program cost increases. Further, pending the development of switching protocols in Phase 2 of the CCA rulemaking, the City could terminate the program, if necessary, and return customers to PG&E service. The program could set aside financial reserves to cover any reentry fees that may be applicable in the case of program termination. For these reasons, the risks of the City forming a CCA program generally remain with the customers that elect to participate in the program. Similarly, customers of PG&E ultimately bear the risks of PG&E's energy procurement practices.

4.1.1 Implementation Plan Stage Risks

At the Implementation Plan stage, the City will have evaluated the feasibility of becoming an Aggregator and assessed the expected costs, benefits, and risks of implementing a CCA program. To progress to the next phase, the City will need to commit additional funds for the development of an Implementation Plan. The primary risk at this stage is political, especially if PG&E directly or indirectly opposes the CCA program. Whereas each of the local utilities has publicly supported CCA, there are always caveats that in practice might cause them to oppose a specific implementation effort as it progresses towards an Implementation Plan.

Typical utility responses to local government energy initiatives are to urge the local government's leaders to slow down so as not to rush into something they do not fully understand. The utility may criticize the feasibility study's assumptions and methodology and suggest that becoming an Aggregator entails great risk with little or no commensurate benefits. Furthermore, PG&E may formally oppose elements of the Implementation Plan at the CPUC. For example, each of the utilities has voiced opposition to allowing Aggregators to phase-in operations over a multi-year period, and phase-in proposals contained in an Implementation Plan may be protested. In the extreme case, the utility might sponsor community organizations to oppose the program, as has been done by both SCE and SDG&E in their efforts to oppose municipalities from forming distribution utilities within their historical service territories. While such strong opposition to a potential CCA program is unlikely, the City should be realistic and not expect complete support from the utility for its efforts.

Once a commitment to developing the Implementation Plan is made a fairly intensive effort will be required to decide the particulars of the CCA program. Choices must be made regarding program management and organizational structure, suppliers and resources, rates and customer protections, terms and condition of service, financing and staffing.

At this stage, there is also the regulatory risk that the CPUC will adopt or modify implementation rules to the detriment of the CCA program or in a way that requires modifications to the Implementation Plan. The development of the Implementation Plan can be done in parallel with the CPUC process. The Implementation Plan should be filed with the CPUC after the CPUC issues its final (Phase 2) in order to avoid the potential expense of re-filing the plan. However, delays in the CPUC process can derail the implementation effort if the process is dragged out indefinitely. Elected leaders that were early supporters of implementing a CCA program may finish their terms before the program can be implemented, and newly elected leaders may desire to reconsider the decision to proceed with CCA implementation. Turnover of key staff could also jeopardize timely program implementation.

4.1.2 Operational Planning Stage Risks

Following development and acceptance of the Implementation Plan, the City will begin making commitments to be able to commence operations. Depending on how the City elects to structure its program, additional funds will be needed to finance the start-up activities. These may include the following:

- Conduct recruiting and staffing
- Develop informational and program marketing materials
- Establish call center for customer inquiries
- Contact key customers to explain program, obtain commitment, and release customer information
- Prepare short and long-term load forecast
- Develop capability or negotiate contracts for operational services
  - Electronic data interchange with utility: accept meter and usage data, send billing data, accept payment and remittance information, exchange customer switching information
  - Customer bill calculations

  - Scheduling coordinator services
  - Application of statistical load profiles and submittal of hourly usage data for grid operator settlements
  - Resource planning, portfolio and risk management
  - Ratemaking
  - Load forecasting
  - Wholesale settlements
  - Credit
  - Information Technology
- Execute contracts for electric supply
- Identify generation projects and negotiate participation, if applicable
- Obtain financing for program capital requirements
- Execute service agreement with utility
- Complete utility technical testing
- Establish account with utility
- Send customer notices to eligible and ineligible (e.g., direct access) customers
- Process customer opt-out requests
- Submit notification certification to CPUC

These commitments should not be made until the CPUC has finalized the rules for CCA implementation, which is expected to take place in June 2005. At that point, the regulatory risk diminishes significantly, and the City has a great deal more certainty regarding the detailed processes that will be required for operating a CCA program.

4.1.3 Operations Stage Risks

The primary risks inherent in the CCA operations are that unanticipated events cause the City's costs to increase or the rates of PG&E to decrease. In that case the rates charged by the City could exceed those of PG&E, and customers may become dissatisfied with the program. To the extent customers are not precluded from leaving the program, the City could face stranded costs and higher rates prompting additional customers to leave the program. Appropriate program rules that limit customer switching or that impose exit fees to compensate remaining program customers for commitments made on behalf of the departing customers will mitigate the risk of losing customers. However, if customers find themselves obligated to a program with higher rates than those offered by PG&E (or other competitors), their dissatisfaction may be directed at those responsible for administering the program. These risks highlight the importance of clear disclosures in the customer notification process so that potential customers are clearly informed of their rights and obligations prior to taking service in the program.

The predominant cost of service variables and risks that might impact the City's operations cost are as follows:

- The cost responsibility surcharge will vary year-to-year. The CRS is inversely related to the prevailing market price of electricity such that if market prices fall, the CRS will increase. To the extent the CRS increases and the City has locked in electricity prices through long-term electricity or fuel contracts, the CCA customers' total rates will increase. The CRS could also increase if the CPUC allows PG&E to include new power purchase contracts or resources in the CRS, and the costs are above prevailing market prices.

- The City could improperly hedge its exposure to electricity and/or natural gas price volatility, and adverse price movements could cause rate increases for its customers. Similarly, the City could over-rely on long-term contracts with fixed prices and find itself holding a high cost portfolio if market prices subsequently fall.

- The City could fail to properly secure its customer base, making debt financing via the capital markets impossible to obtain and exposing the City to stranded costs if customers opt-out of the CCA program. Even with appropriate switching rules, large customers may go out of business or leave the area and leave behind costs that must be paid by remaining program customers.

- The City's energy suppliers could default on supply contracts (credit risk) at times when energy spot markets are high, forcing the City to purchase energy at excessively high prices. Customers could fail to pay the City's charges, and the City's credit policies and customer deposits may be insufficient to recover the uncollectible bills .

- PG&E could make changes to its rate designs that reduce the cost of generation services and increase the costs of delivery services or that shifts costs among customer classes in a manner that disadvantages the customer mix served by the City.

- Other regulatory risks associated with changes in the rules and tariffs administered by the CPUC or in the wholesale markets regulated by the Federal Energy Regulatory Commission (FERC) could increase the City's cost of providing service. For example, the institution of a requirement to use geographic-specific load profiles for electricity procurement could advantage coastal communities to the detriment of those located in hotter, inland climates.

Each of these risks can be mitigated, although not altogether eliminated. The City can structure its program in such a way that it would be exposed to very little risk. Electricity supply contracts can be structured to transfer many of the risks to the program's suppliers. The following table describes basic risk management techniques for each of the primary risks associated with operating a CCA program.

Risk	Mitigation
Cost Responsibility Surcharge Volatility	Utilizing shorter duration supply contracts to a greater extent than would otherwise be indicated would offset the CRS risk. If market prices decrease, the City's supply portfolio costs will also decrease, offsetting the increase in the customer's CRS payments to PG&E.
Commodity Price Volatility	Diversify supply portfolio with contracts of various terms and with multiple suppliers, renewable energy, and conventional generation. Layoff commodity price risks to energy suppliers through fixed priced contracts or guaranteed discount pricing structures
Customer Attrition	Establish exit fees following free opt-out period. Negotiate term contracts with large customers.
Credit Risk	Periodic credit and exposure monitoring; supplier diversity; collateral and surety instruments. Require deposits from customers and return to utility for failure to pay bills.
Utility Rate Changes and Other Regulatory Risks	Participate in CPUC process to prevent shifting of costs to program customers

4.1.3.1 Operations Risk Discussion

Ultimately, the major operational risks are under the control of the program's management. Disciplined, professional management is key to managing risks inherent in offering retail electric services. The City will be able to contract for services from a variety of large, experienced energy suppliers that have operational capabilities equal to or better than those of PG&E. It should be noted that municipal utilities have been successfully managing commodity, credit, and operational risks for many decades, even during times of high commodity prices and supply shortages.

The experiences of PG&E, SCE and SDG&E during the energy crisis of 2000-2001 illustrate what can happen when risks are not properly managed. The investor owned utilities' exposure to commodity price risks during the energy crisis and the ensuing financial devastation experienced by PG&E and SCE stemmed from an artificial constraint imposed by the CPUC on their hedging abilities, coupled with an inability to increase retail rates due the legislated rate freeze. The CPUC's so-called buy/sell requirement forced the utilities to buy 100% of their energy from the state sanctioned (now defunct) California Power Exchange daily market auction and sell 100% of their generation resources into that market. Because the utilities had divested nearly all of their natural gas fired generation resources, they were each heavily short on resources and overly reliant on the spot market. When spot market prices spiked for an extended period of time, the cash drain necessitated the State of California (Department of Water Resources) to take over electricity procurement responsibilities from the utilities. Customers of SDG&E were not protected by the rate freeze and suffered from excessive rates as SDG&E was able to pass through its costs of procuring electricity from the spot markets.

The City will not be subject to these types of constraints on its procurement practices. Being a municipality, it will exercise its own authority over its resource planning and ratemaking decisions. A professionally managed electricity procurement program, following sound risk management practices, would not expose itself to the risks that the investor owned utilities faced during the energy crisis.

4.1.3.2 Regulatory Risk Discussion

Regulatory risks refer to the potential that decisions by regulators could cause cost increases for the CCA program. The City can participate in regulatory proceedings at the CPUC or FERC to try to influence the regulatory process to protect its interests and those of its customers. Typically, associations are formed among entities with common interests to participate on their behalf in the regulatory process to effectuate maximum influence on regulators. The amount of influence wielded in the regulatory process depends on the resources the association can devote to participation and the political influence of the associations members. Thus, to some extent the degree by which regulatory risk can be managed depends upon the prevalence of CCA throughout the state. If CCA becomes a widespread phenomenon, with many communities being directly impacted by CPUC decisions, the CPUC is less likely to make decisions that impose additional costs on Aggregators than if only one or two communities would be impacted.

4.1.4 Risk Mitigation Through Physical and Financial Reserves

Physical and financial reserves are important components of a CCA program that reduce program risk. Industry rules dictate certain reserve requirements for all market participants to protect the integrity of the system. These rules ensure no degradation of reliability would result if the City were to implement a CCA program.

4.1.4.1 Physical Reserves

The program will be required to comply with industry rules governing the provision of physical reserves to ensure reliable operation of the electric grid. The California Independent System Operator (CAISO) requires load-serving entities to maintain operating reserves (6% to 8% of load) and regulating reserve (2.5% to 5%) that can be quickly called upon in the event that scheduled resources experience outages or electricity consumption unexpectedly increases. Load serving entities can arrange for their own reserves, or the CAISO will charge the load serving entity for the costs of reserves procured on its behalf. The costs of these reserves are included as an expense item in the pro forma.

On a longer-term basis, the CPUC requires load-serving entities to arrange for a 15% planning reserve margin, approximately one year in advance. The planning reserve requirement was instituted in 2004 and is in intended to both ensure the existence of adequate generation capacity as well as to reduce the ability of power suppliers to charge high electricity prices that can occur when capacity is scarce. The costs of planning reserves are included as an expense item in the pro forma.

4.1.4.2 Financial Reserves

The program will maintain financial reserves in the form of rate stabilization funds or other reserve funds that would be required by the banks to support debt financing of program assets. Rate stabilization funds are maintained at the discretion of program management and the program's governing board. They are used to cushion short-term cost increases as well as to accrue cash for future capital expenditures. To the extent that debt financing is utilized to fund capital expenditures, banks will require minimum debt service reserves equal to approximately 10% of the amount borrowed, and will also impose minimum debt service ratios to ensure adequate debt service coverage. These financial reserves are included in program rates, but these funds are an asset of the program that will ultimately be accessible for future rate reductions or other program purposes.

4.1.5 Risk Mitigation Through Phased Implementation

The City could implement a CCA program in phases to limit any risks associated with program startup and the transition of customers from PG&E to service by the program. An example could be to initially offer the program to non-residential customers for a pilot phase such as six months or one year and then to open the program to all customers after the pilot phase is completed. By starting with non-residential customers, the number of transactions (account transfers, monthly billing, etc.) that must be completed would be a small fraction of what would be required to serve the entire community at one time. Another benefit of this type of phasing arises because non-residential customers are higher margin customers so the initial phase-in period would provide greater margins for the program to help cover program startup costs.

The CPUC will not determine which customers the CCA should serve.[8] However, the City must comply with the legal requirements of AB 117 that requires equitable treatment of all customer classes and the offering of service to all residential customers. The Implementation Plan should describe the phasing approach, if any, that the City intends to utilize and how that approach complies with the law.

[8] See D.04-12-046, Conclusion of Law No. 38.

5 FEASIBILITY ANALYSIS

5.1 Study Approach

In preparing the financial evaluation for a CCA program, NCI did a thorough analysis of: (1) PG&E's forecasted rates (including cost responsibility surcharges); (2) CCA energy or commodity costs (including generation ownership, power purchase contracts, renewable energy contracts and spot-market purchases; (3) CAISO charges; (4) operations and scheduling costs; (5) financing costs; and (6) revenue offsets and available financial incentives. Each of these items was factored into the pro forma analysis. The CCA program's capital costs are amortized over a 30-year period and financed at a rate of 5.5%. The interest and amortization are included in the annual costs of the program. The financial pro forma analysis compares the total costs of operating the CCA program with the total costs of continuing to take retail utility service from PG&E.

A financial analysis was performed in order to develop financial pro forma, which are then structured as consolidated statements of income for the CCA program. The consolidated statements based on the financial pro forma are located in Appendix E. As noted above, savings or potential income is the margin between current retail power costs, as provided by PG&E, and the City's projected cost to provide the power. NCI began its evaluation with a planning horizon beginning in the current year (2005) and then projected costs 20-years forward to 2024.

PG&E provides services at regulated cost-based rates. Hence, PG&E's rates are directly tied to a demonstrated "revenue requirement", which is the total revenues the utility is authorized to recover through rates. The revenue requirement includes the utility's expenses, return or profit, and taxes paid by the utility. The financial analysis provided herein compares PG&E's revenue requirement at current and projected rates with the revenue requirement of the CCA program to determine potential savings or income. Pro forma summary tables compare each supply portfolio based on their relative ability to produce operational cost savings or benefits.

In a CCA program, utility service is limited to the electric energy commodity only. PG&E would continue to provide electricity delivery over its existing distribution system and provide end-consumer metering, billing, collection and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). Accordingly, to evaluate the potential benefits for CCA, only costs associated with wholesale electric commodity procurement and related business expenses are considered.

5.2 Customer Base

The potential customer base for the CCA program is all of the electric customers in the City. However, customers have the option to opt-out of the CCA program and continue to receive their electric service from PG&E. Some customers may choose to not participate in the program, or opt-out during the 60-day opt-out period, and some direct access customers may be contractually prevented from initially joining the program until their direct access contracts expire. The prevalence of customer opt-outs will depend on a number of factors, not the least of which is how the City's electric rates compare to those of PG&E. Other factors that will influence customers' opt-out decisions include whether the City provides non-price features important to customers such as increased renewable energy purchases or expanded energy efficiency programs; customer loyalty or enmity to PG&E; and other customer perceptions. Many of these factors are directly dependent on the details of the City's Implementation plan, and the impacts cannot be reasonably estimated prior to completion of the City's implementation planning process. For the purposes of this feasibility analysis, the report presents the potential benefits from CCA, assuming 100 percent customer participation. Within a reasonable range of assumed opt-out percentages, the study results can be adjusted proportionately.

5.3 Key Assumptions

As described in Section 2.2, the CPUC is in the process of finalizing the rules for CCA implementation. NCI developed several framework assumptions for this feasibility analysis and also adopted a set of detailed assumptions for various unknown costs and implementation rules. This section describes the high level assumptions that provide the framework for the analysis. The detailed assumptions are listed in Appendix B.

1. CCA Rulemaking is completed by the third quarter of 2005, and CCA operations can begin in January 2006

2. Charges authorized by the CPUC for Aggregators and CCA customers are similar to those charged to direct access customers (transaction and implementation fees)

3. Aggregators must maintain adequate capacity reserves to maintain reliability standards and will follow standard industry risk management practices. Aggregators will be held to the same capacity reserve standard as PG&E.

4. Aggregators will match or exceed the renewable energy content of PG&E's portfolio and are eligible for the existing CEC subsidies provided for renewable energy procurement up to the minimum renewable portfolio standard (i.e., subsidies are available for the first 20% of renewable energy)

5. Market prices for renewable energy will reflect the developer's costs, including the effects of available subsidies

6. Aggregators can finance generation projects

7. Aggregators can obtain electricity from the wholesale market on comparable terms with the IOUs

8. The CPUC does not allow IOUs to negotiate special rates or contracts to retain customers

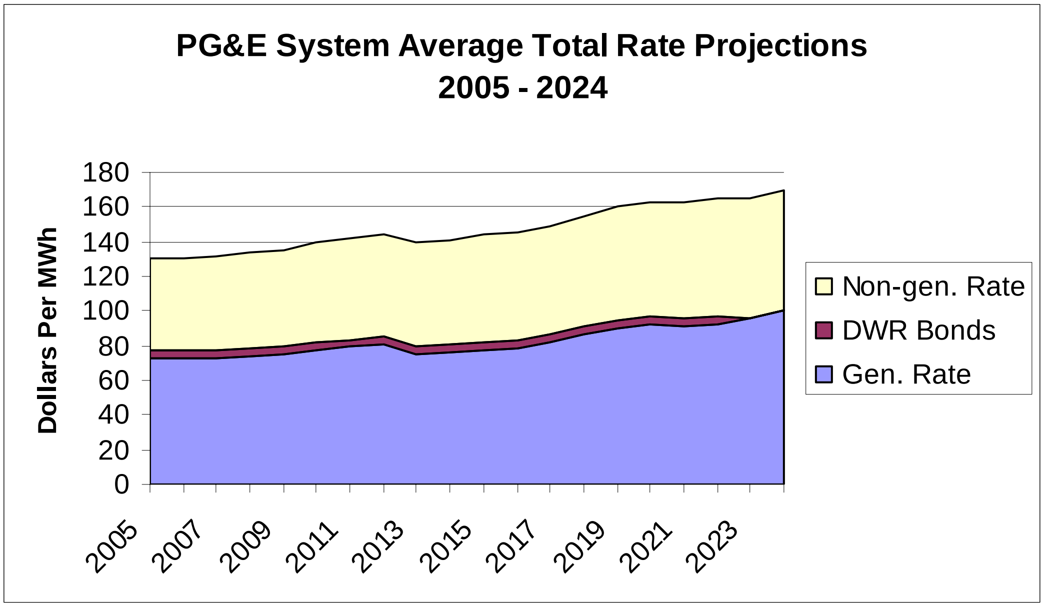
9. CCA operations can be outsourced to third parties

10. Reinstatement of direct access does not preempt CCA rights and customer relationships

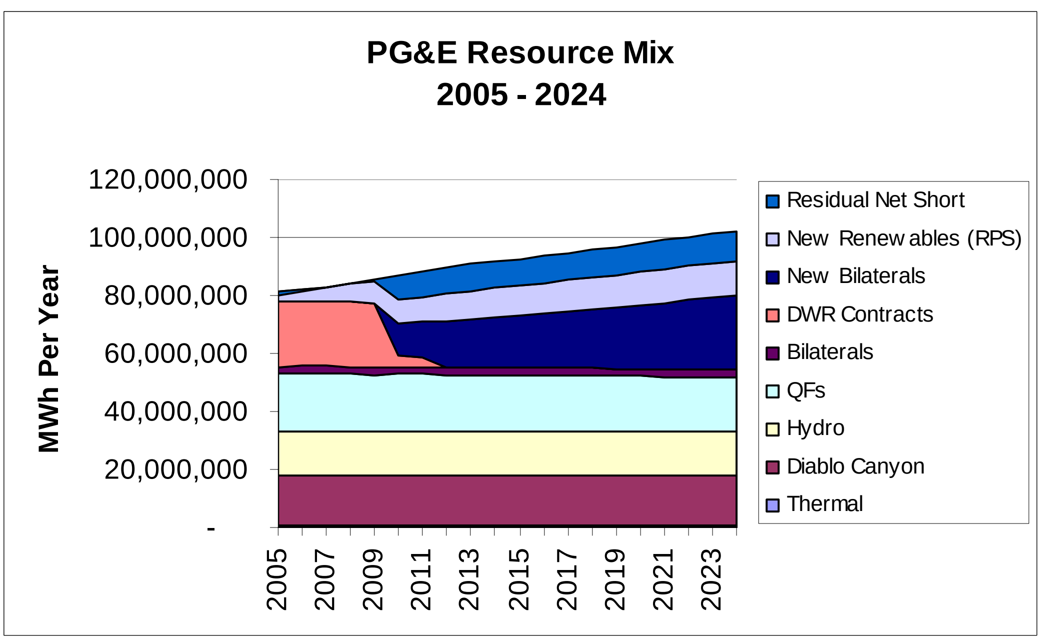
5.3.1 Utility Rate Benchmarks

Estimates of CCA cost savings potential are assessed by comparing CCA costs to the rates that would otherwise be charged by PG&E. PG&E's rates derive from its costs or revenue requirement, and NCI modeled PG&E's annual generation revenue requirements for the 2005 to 2024 study period. The resulting rate projection shows generation rates increasing at a modest average rate of 1.7% per year due to offsetting influences on PG&E's generation costs. The projected annual rate increase of 1.7% is at the low end of historical trends.[9] The reason for this is that generation cost increases are somewhat offset by the expiration of high cost DWR contracts in the 2004 to 2012 period, and the net result is a moderately increasing rate forecast. Once the DWR contracts expire in 2012, PG&E's generation costs are expected to show annual increases consistent with general levels of inflation and gas price escalation.

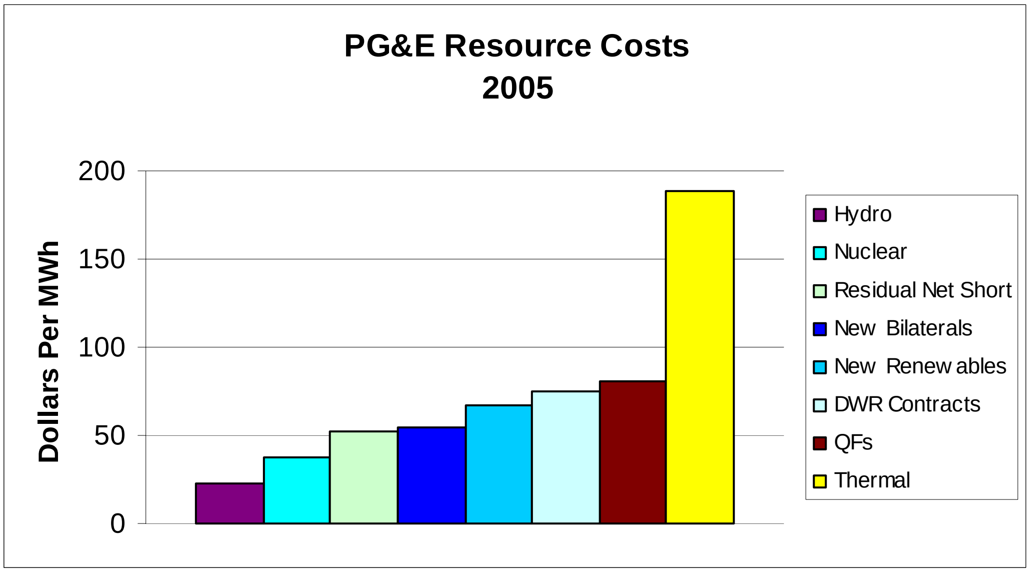
[9] Depending upon the specific timeframe selected for comparison, during the past twenty-five years, SDG&E rates have increased by an average annual rate of between 1% and 4%.



PG&E's generation revenue requirements are modeled for each resource in PG&E's generation portfolio, including the DWR contracts the CPUC allocated to PG&E in Decision No. 02-09-053. As production from existing resources or supply contracts decline over time, they are replaced by new power purchase contracts at prevailing market prices. Short-term "spot market" purchases are maintained at 15% of the total portfolio. New renewable contracts are added to the resource mix to meet the applicable Renewable Portfolio Standards requirements, and planning reserve requirements of 15% are enforced in the rate projections.



The revenue requirement for each resource type was modeled based on data provided by PG&E in its 2003 Cost of Service Proceeding and FERC Form 1 filings. The current costs are shown below. Costs were projected forward for the study period by calculating annual depreciation, operations and maintenance expenses, taxes, and authorized return on rate base for each resource.



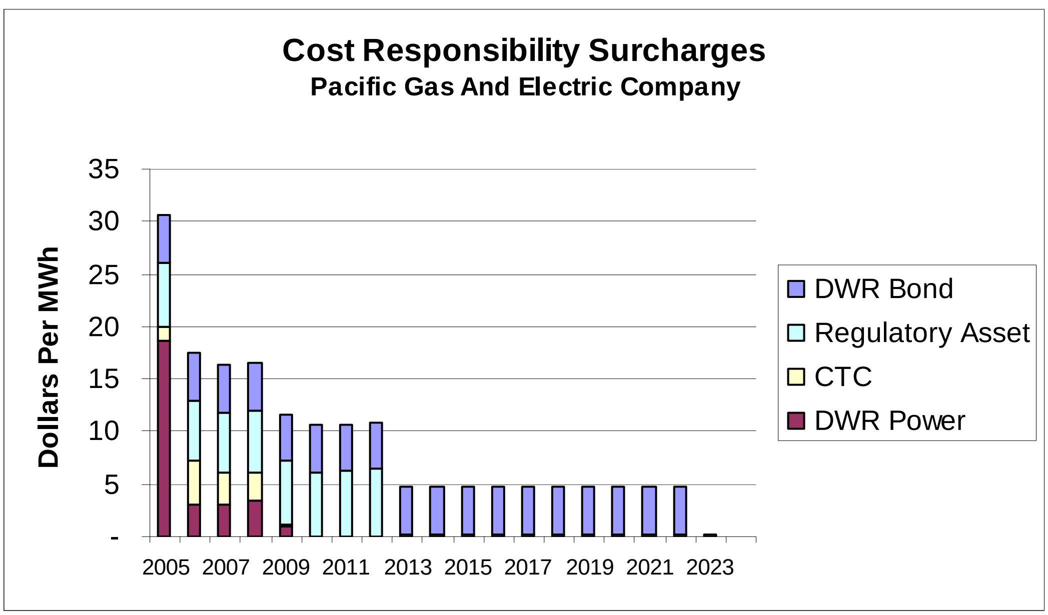
* The per unit cost of thermal resources is high due to the limited energy production from these resources which are primarily used to provide system reserves.

5.3.2 Cost Responsibility Surcharges

The single greatest obstacle to achieving significant cost savings through CCA in the next several years is PG&E's imposition of cost responsibility surcharges on CCA customers, which are designed to shield PG&E from any financial losses or cost increases that might result from customers switching to service by the City. NCI modeled expected cost responsibility surcharges using the methodology adopted in the CCA Phase 1 Decision (D.04-12-046). According to this methodology, the above market portion of PG&E's generation portfolio, including PG&E contracts and resources and the DWR contracts, are included in the CRS. Other elements of the CRS include the DWR Bond Charge and, for PG&E, the charge for recovery of the "regulatory asset" that was established to enable PG&E's emergence from bankruptcy. The latter two costs are reasonably certain and predictable, while the uneconomic portfolio costs are less easily predicted because they directly depend on future electricity market prices and PG&E's future generation costs.

The interim uneconomic portfolio costs CRS component of 2.0 cents per kWh adopted in D.04-12-046 was used for 2005 and reduced to the actual cost estimate in 2006 and subsequent years.[10] The CRS cost estimates are consistent with the electricity cost projections underlying the City's modeled supply portfolio, and these are somewhat higher than the estimates used by the CPUC to develop the 2.0 cents per kWh interim CRS. As a result, the CRS is expected to decline sharply from the interim number in 2006. If future power prices are lower than those projected for the base case, the CRS would be higher and the cost of procuring power for the CCA program would be lower. These two impacts tend to offset each other. Therefore, the magnitude of the CRS should not be looked at in isolation, but should be assessed in context with the market price assumptions used in the overall feasibility assessment. The net effect of higher or lower power prices on the overall cost of service for the CCA program can be seen in the sensitivity analysis results presented in Section 6.3.

The following chart shows the components of the CRS for PG&E over the study period under the base case scenario.



With the exception of the DWR bond charge, the CRS is expected to become zero by 2012, as DWR contracts expire, market prices trend upwards, and the cost of the regulatory asset is fully recovered.

[10] The 2.0 cents per kWh interim CRS is in addition to the DWR Bond Charge and the Regulatory Asset.

5.3.3 Renewable Energy Subsidies

A variety of tax incentives, credits and publicly funded subsidies exist for renewable energy development, which reduce the effective cost of increasing the renewable energy content of the program's supply portfolio. These include the following subsidies:

- Production Tax Credits
- Renewable Energy Production Incentives
- Supplemental Energy Payments (Public Goods Funds)

Some of the incentives, such as the production tax credit for renewable energy production, are short-term and must be reauthorized by Congress on an annual basis. Others, such as the public goods funding for renewable energy development administered by the California Energy Commission ("Supplemental Energy Payments"), are more long lived, but are contingent on the sufficiency of the public goods fund collected through utility rates. The economic analysis conducted for the City includes the effect of Supplemental Energy Payments available to producers of renewable energy as described in more detail below. The other potential subsidies are not included in the analysis although they may ultimately be available to further reduce the program's cost of service.

Subsidies are included for renewable energy purchases from the market, to the extent such purchases are needed to supplement production from the City's resources. The renewable energy costs for purchases up to the minimum renewable portfolio standard are offset by Supplemental Energy Payments, while the incremental renewable energy above and beyond the minimum requirement is assumed to receive no subsidy. Thus, the costs of renewable energy utilization above the first 20% would be paid entirely by customers of the CCA.

No Supplemental Energy Payments are assumed to be available to offset costs of the City's renewable resources that it owns or otherwise finances. The reason for this assumption is that the process for determining Supplemental Energy Payments was premised on the utilities conducting competitive solicitations for long-term supply contracts with producers of renewable energy. Funds are made available to winning bidders to cover the excess of their costs above a market benchmark, determined by the CPUC. The CPUC has so far been focused on how the utilities are to meet the Renewable Portfolio Standards, and the rules and protocols for making Supplemental Energy Payments available to Community Choice Aggregators have not yet been established.

It is unclear at this time how the process developed for the utilities would apply to an Aggregator that develops its own renewable resources rather than procures renewable energy through long-term, competitively solicited contracts. Financing structures that entail prepayment for energy through long-term power purchase contracts with a renewable energy producer should theoretically allow the City to receive the benefits of its financing advantages and also qualify the producer for Supplemental Energy Payments. However, as stated above, the rules have not been established, and the conservative assumption that no such subsidy would be available was used in this analysis.

5.4 Financial Analysis Structure

CCA customer population electric loads are applied to PG&E's current and projected generation rates to yield its revenue requirement recovered from the customers in the potential CCA area. CCA operating expenses are projected and subtracted from PG&E's revenue requirement to yield the projected financial benefit. Elements contained in the analysis are summarized below and details of the inputs, assumptions and sources are provided in Appendix B:

<u>Utility Forecast Generation Rates</u>
- Utility Retained Generation
- Qualifying Facility Generation
- Bilateral Power Purchase Contracts
- New Renewable Energy Purchases
- CAISO charges
- Residual Spot Market Purchases or Sales

<u>CCA Energy Cost (Commodity Costs)</u>
- Spot Market Purchases
- Power Purchase Contracts
- Renewable Energy Contracts
- Generation Ownership

<u>California Independent System Operator Charges</u>
- Ancillary Services/Reserves
- Grid Management Charges
- Deviation Charges

<u>Operation and Scheduling Costs</u>
- Electricity Procurement
- Risk and Credit Management[11]

[11] The costs of uncollectible customer accounts are not explicitly included in the pro forma, under the premise that the Aggregator would require customer deposits from customers that pose likely credit risks,

- Load Forecasting
- Scheduling and Settlements
- Rates
- Account Services
- Administration

<u>Non-Bypassable Charges/Cost Responsibility Surcharge</u>

- Uneconomic Utility Retained Generation and Power Contracts
- DWR Power Purchase Contracts
- DWR Bond Charges - Financing Past Purchases

5.5 Load Analysis

Detailed definition of community electric power needs is required to assess the economic viability of the CCA providing electric energy as an alternative to the community's existing supplier, PG&E. Community electric demand and energy consumption, generally referred to as electric load, has been analyzed and described in charts and graphs located in Appendix G. NCI performed load analysis and constructed a load forecast beginning with and based upon data provided by PG&E in response to the Community's formal request (see Appendix C for sample data request letter). The Community's annual hourly load shape was developed, and a determination made regarding associated energy supply requirements. The time-of-use supply requirements serve to define the types of resources necessary to supply electric energy to the CCA.

5.5.1 Load Forecast Methodology

Community electric load data provided by PG&E was 12-month, year-to-date energy consumption and number of customers by rate class as of October 2003. PG&E provided up to 20 rate classes that NCI collapsed into 7 higher-level Customer Sectors. Rate classes and their generic sector rate class description assignments are listed in the following table:

---

similar to the accepted utility practice. Because under current rules the Aggregator cannot cause service to be shut-off to the customers for failure to pay its portion of the bill whereas the utility can, it is important that the Aggregator have the ability to screen customers prior to automatic enrollment for administration of its credit policies and that the Aggregator has the right to return the customer to the utility for failure to pays its charges. This issue should be addressed in Phase 2 of R.03-10-003.

Rate Schedule to Customer Sector Assignment

Rate Schedule	PG&E Description	Customer Sector Description
A-1	Small General Service	Small Commercial
A-6	Small General Time-of-Use Service	Small Commercial
AG-1	Agricultural Power	Small Commercial
A-10	Medium General Demand-Metered Service	Medium Commercial
E-1	Residential Service	All-Residential
E-2	Experimental Residential Time-of-Use Service	All-Residential
E-3	Experimental Residential Critical Peak Pricing Service	All-Residential
E-7	Residential Time-of-Use Service	All-Residential
E-8	Residential Seasonal Service Option	All-Residential
E-9	Experimental Res Time-of-Use Service for Low Emission Vehicle Custs	All-Residential
EML	Master-Metered Multifamily CARE Program Service	All-Residential
ES	Multifamily Service	All-Residential
ETL	Mobile Home Park CARE Program Service	All-Residential
E-19	Commercial/Industrial/General Medium General Demand-Metered Time-of-Use Service	Large Commercial
E-20	Commercial/Industrial/General Demand Greater than 1,000 Kilowatts	Large Commercial/Industrial (C/I)
LS-1	PG&E Owned Street and Highway Lighting	Street Lighting
LS-2	Customer-Owned Street and Highway Lighting	Street Lighting
LS-3	Customer-Owned Street and Highway Lighting Electrolier Meter Rate	Street Lighting
OL-1	Outdoor Area Lighting Service	Street Lighting
TC-1	Traffic Control Service	Traffic Control

The monthly load information was ordered by month; January through December, to reflect monthly seasonal use patterns and treated as prototypical for 2003 energy consumption. PG&E published static load profiles were employed to allocate monthly energy (kWh) into each hour of the month and then to each of the 8,760 hours within a year. Rate class static load profiles where selected as most characteristic of load usage patterns in each of the Customer Sectors as reflected in the following table:

Static Load Profile Assignment

Customer Sector	Static Load Profile
Small Commercial	A-1
Medium Commercial	A-10
Large Commercial	E-19
Large (C/I)	E-20
Street Lighting	LS-1
Traffic Control	TC-1

A twenty-year electric load forecast was performed forecasting electric demand energy requirements for years 2005 through 2024. Electric energy requirements and customer populations were escalated based upon sector specific growth planning statistics provided by the City; if none was provided PG&E system-wide growth rates were applied.

The number of customer accounts and annual energy sales for the initial year (2006) of the program are shown below.

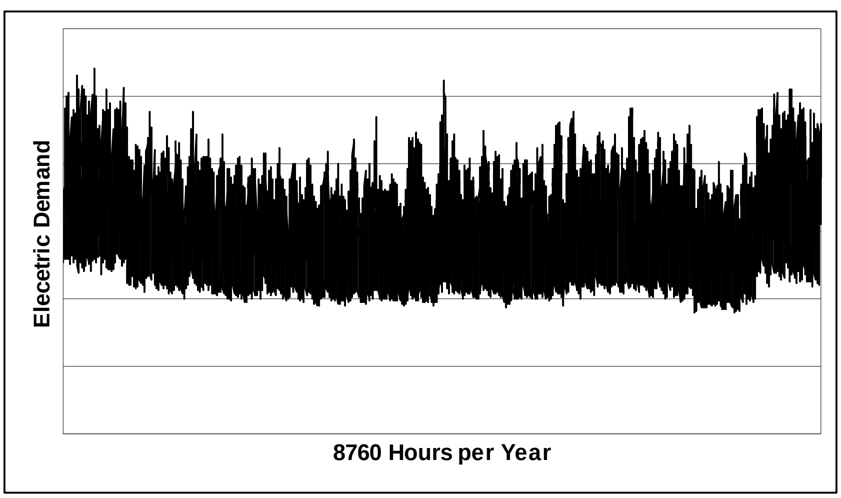
	2004 *		2005 *		2006 *	
	Accounts	kWh	Accounts	kWh	Accounts	kWh
Residential	4,802	19,935,016	4,874	20,234,041	4,947	20,537,552
Small Commercial	739	24,036,128	750	24,396,670	761	24,762,620
Medium Commercial	194	49,535,431	197	50,278,462	200	51,032,639
Large Commercial	50	41,401,045	51	42,022,061	52	42,652,391
Large C/I	6	63,321,680	6	64,271,505	6	65,235,577
Street Lighting	16	1,362,893	16	1,362,893	16	1,362,893
Traffic Control	31	112,814	31	112,814	31	112,814
Total	5,838	199,705,006	5,925	202,678,446	6,013	205,696,487

* 2003 Data Provided by Distribution Utility (PG&E) and Escalated by Applying The Following Growth Rates:

Growth Rates	
Residential	1.50%
Commercial	1.50%
Street Lighting and Traffic Control	0.00%

5.5.2 Community Energy Load Shape

The community composite annual energy load shape (average kW per hour) was developed by combining average loads in each hour from each of the Customer Sector static load profiles identified above. A prototypical annual load profile is shown in the following figure.



Electric load was next broken down into quarterly and weekly demand periods to capture seasonal variation in projected loads and electric generation resource requirements. The resulting quarterly minimum, as well as peak power requirements, is the basis for "sizing" the portfolio of contracts and generation resources needed to serve the City's load profile.

5.5.3 Renewable Portfolio Standards Requirements

The California Renewable Portfolio Standard Program (RPS) established by Senate Bill 1078 requires that a retail seller of electricity purchase a specified minimum percentage of electricity generated by qualifying renewable energy resources. Community Choice Aggregators are required under SB 1078 to procure a specified minimum percentage of total kilowatt hours sold to retail end-use customers each calendar year from renewable resources.

Each distribution utility is required to increase its total procurement of eligible energy resources by at least 1% per year so that 20% of its retail sales are procured from eligible renewable energy resources by year 2017. CCA program aggregated loads are a subset of load currently served by the distribution utilities (SCE, PG&E and SDG&E). Therefore, analyses contained herein assume that customer energy requirements of the prospective CCA will, at a minimum, be equal to the renewable energy percentage required of each distribution utility.

Further, when the City applied for and was accepted into the CCA Demonstration Project it declared as a goal to double the RPS and achieve a renewable energy content of 40% by 2017. The following table reflects distribution utility RPS renewable energy requirements projected forward.

Year	PG&E MIN	SCE MIN	SDG&E MIN
2003		16%	5%
2004	12%	17%	6%
2005	13%	18%	7%
2006	14%	19%	8%
2007	15%	20%	9%
2008	16%	20%	10%
2009	17%	20%	11%
2010	18%	20%	13%
2011	19%	20%	14%
2012	20%	20%	15%
2013	20%	20%	16%
2014	20%	20%	17%
2015	20%	20%	18%
2016	20%	20%	19%
2017	20%	20%	20%
2018	20%	20%	20%
2019	20%	20%	20%
2020	20%	20%	20%
2021	20%	20%	20%
2022	20%	20%	20%
2023	20%	20%	20%
2024	20%	20%	20%

The bill requires the CPUC to adopt rules for implementing the RPS, and CCA planners must understand the renewable energy requirements before they can assess the cost-benefits and make threshold decisions to implement a CCA program. City minimum renewable energy requirements are summarized in the table below.

Renewable Resource Requirements Projected Forward

	Energy MWh	Renewable Capacity Requirement (MW)		Renewable Energy Requirement (MWh)	
		1 X RPS	2 X RPS	1 X RPS	2 X RPS
2007	208,760	12	24	31,210	62,419
2008	211,869	13	26	33,793	67,586
2009	215,025	14	28	36,447	72,893
2010	218,228	15	30	39,172	78,344
2011	221,479	16	32	41,970	83,941
2012	224,780	17	34	44,844	89,687
2013	228,129	17	35	45,626	91,252
2014	231,529	18	35	46,306	92,612
2015	234,980	18	36	46,996	93,992
2016	238,482	18	36	47,696	95,393
2017	242,037	18	37	48,407	96,815
2018	245,646	19	37	49,129	98,258
2019	249,308	19	38	49,862	99,723
2020	253,026	19	39	50,605	101,210
2021	256,799	20	39	51,360	102,720
2022	260,629	20	40	52,126	104,252
2023	264,516	20	40	52,903	105,806
2024	268,462	20	41	53,692	107,385

* Capacity figure is based on a capacity factor of 30%, typical of wind resources.

6 FINANCIAL PROJECTIONS

The supply portfolio modeled for the City contains a diverse mix of resources reflective of a strong commitment to promotion of renewable energy.

The resource types include:

- Spot market purchases – short-term electricity purchases to supplement resources under contract control of the City
- Contract purchases – longer term, fixed price power purchases. Terms can be monthly, quarterly, annual or multi-year. For purposes of this analysis, the contracts were structured with sequential two, three, or five-year terms.
- Natural gas power production –production from a combined cycle natural gas combustion turbine owned by the City used for baseload or shaping purposes
- Renewable energy purchases – purchases of renewable energy to meet the City's renewable resource goals, with a minimum equal to PG&E's renewable energy mix. For purposes of this analysis, purchases are from a generic renewable portfolio with a cost equal to the weighted average of the renewable resources expected to fulfill California's RPS.
- Renewable energy power production – production from renewable energy resources owned by the City. For purposes of this analysis, an equity position in wind and geothermal facilities sized to meet the City's renewable resource goals
- Off system sales – sales of excess energy into the spot market at times when the resources under contract or ownership are in excess of the City's load requirements

The total cost of service for the CCA program was calculated and compared to the generation costs charged by PG&E. The difference represents potential savings or costs associated with the CCA program. These savings are shown for each year in the study period, with positive numbers indicating lower costs for the CCA and negative numbers indicating higher costs. Costs or savings are shown both in millions of dollars per year and as a percentage of customers' monthly electric bills.[12]

[12] The percentage savings are expressed based on total electric bills, including PG&E delivery charges. The percentage savings on the generation component of bills would be approximately double the percentages shown.

Summary Of Electric Cost Savings From Community Choice Aggregation
Base Case Scenario
(Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	16.1	17.9	1.8	6%
2007	16.2	18.2	2.0	7%
2008	17.1	18.9	1.8	6%
2009	16.5	19.4	2.9	9%
2010	17.2	20.4	3.2	10%
2011	17.8	21.0	3.2	10%
2012	18.4	21.7	3.4	10%
2013	17.4	20.6	3.2	10%
2014	17.9	21.2	3.3	10%
2015	18.7	21.9	3.3	9%
2016	19.1	22.5	3.4	9%
2017	19.8	23.6	3.8	10%
2018	21.0	25.3	4.4	11%
2019	22.0	26.9	4.9	12%
2020	23.1	27.8	4.7	11%
2021	23.4	28.0	4.7	11%
2022	23.9	28.7	4.8	11%
2023	23.6	28.9	5.3	12%
2024	24.9	30.6	5.8	12%
Total	373.8	443.5	69.7	10%

Total nominal savings over the study period are $69.7 million or approximately 10% of customers' total electricity costs. Cost savings average approximately $3.7 million per year.

6.1 Supply Portfolio Details

The CCA program would be supplied from a diverse portfolio of energy resources. The portfolio is designed to achieve the City's 50% renewable energy objective in stages. The City initially matches the renewable content of PG&E's portfolio and incrementally increases the renewable component to achieve a mix of 50% by 2017. The City invests in generation resources to meet its baseload energy requirements. The portfolio also includes power purchases through five-year contracts and spot market purchases to supplement the production of the City's generation resources.

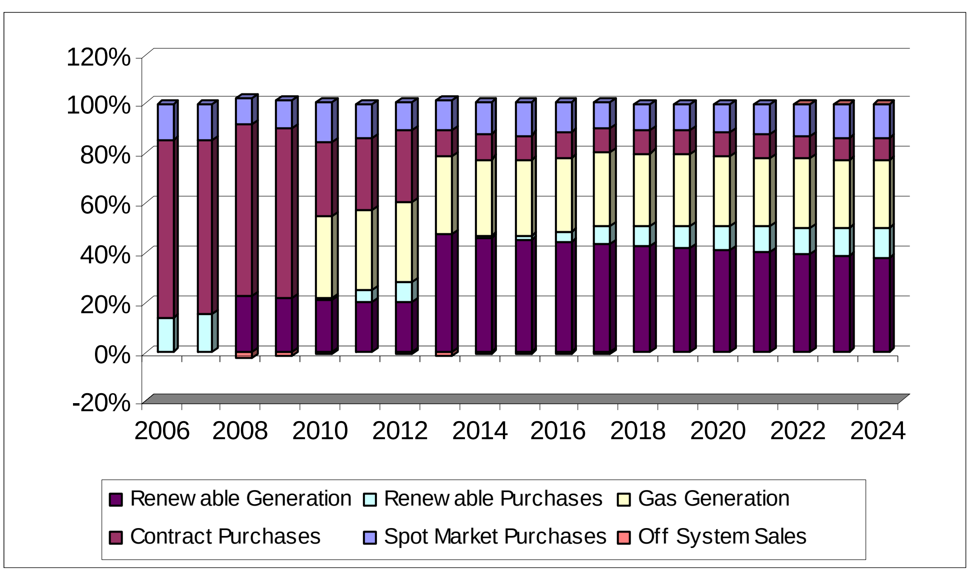
The resource mix includes both conventional and renewable resource ownership. The portfolio initially contains only purchases from the open market, and beginning in 2008, it includes production from wind and geothermal resources. 2008 was selected as the earliest feasible date for the City to acquire equity in a new generation resources, considering lead times for negotiations, permitting and financing.

CCA Generation Resources In CCA Portfolio

Resource Type	Capacity (MW)	On-line	Capital Cost ($ Millions)
Wind	10	2008	11.2
Geothermal	3	2008	8.3
Gas Combined Cycle	10	2010	8.0
Wind	25	2013	31.3

The assumed renewable generation resources were sized to meet the City's renewable energy target projected for the next several years. As a result, the portfolio initially contains greater renewable energy than targeted. Later, as load growth continues, the renewable production must be supplemented with renewable energy purchases to meet the City's targeted renewable percentage of 50.

Long Term Resource Mix Utilized For Financial Pro Forma



No subsidies are assumed to be available to offset costs of the City's renewable resources. Subsidies are included for renewable energy purchases, to the extent such purchases are needed, consistent with the subsidy treatment discussed in Section 5.3.3.

Capital expenditures associated with the preferred portfolio include startup costs of $400 thousand and generation investments of $20 million in 2008, $8 million in 2010, and $31 million in 2013.

6.2 Alternative Supply Scenarios

Financial pro forma were prepared for four additional supply portfolios that differ by varying the mix of renewable energy in the portfolio and by whether the City owns generation resources used to supply electricity to the program. The pro forma for the alternative supply portfolios are included in Appendix F. Analysis of the alternative supply scenarios can assist the City in understanding the cost effectiveness and tradeoffs among different resources that could be included in a portfolio to supply the CCA program.

6.2.1 Alternative Supply Scenario 1

Supply Scenario 1 assumes the City doubles the renewable content of PG&E and purchases all of its load requirements from the open market. Inclusion of renewable energy increases the portfolio's cost, even after considering the subsidies potentially available to the City's renewable energy suppliers. The renewable energy costs for purchases up to the minimum renewable portfolio standard are assumed to be offset by supplemental energy payments administered by the CEC, while the incremental renewable energy above and beyond the minimum requirement is assumed to receive no subsidy. Thus, the second 20% of targeted renewable energy is paid entirely by customers of the CCA.

Capital expenditures associated with Scenario 1 is limited to program startup costs estimated at $400 thousand.

This supply strategy results in total savings over the study period of $12.3 million or 2% of total electricity costs.

6.2.2 Alternative Supply Scenario 2

Supply Scenario 2 assumes the City matches the renewable content of PG&E and purchases all of its load requirements in the open market. Renewable energy subsidies are available to offset the incremental cost of the City's renewable energy purchases.

Capital expenditures associated with Scenario 2 is limited to program startup costs estimated at $400 thousand.

This supply strategy results in total savings over the study period of $19.0 million or 3% of total electricity costs.

6.2.3 Alternative Supply Scenario 3

Supply Scenario 3 assumes the City doubles the renewable content of PG&E and produces electricity from resources that it owns. The portfolio also includes power purchases through five-year contracts and spot market purchases to supplement the production of the City's generation resources. Supply Scenario 3 includes both conventional and renewable resource ownership. The portfolio initially contains only market purchases similar to Supply Scenario 1, but beginning in 2008, it includes production from wind and natural gas-fired, combined cycle resources. 2008 was selected as the earliest feasible date for the City to acquire equity in a new generation resources, considering lead times for negotiations, permitting and financing.

No subsidies are assumed to be available to offset costs of the City's renewable resources. Subsidies are included for renewable energy purchases, to the extent such purchases are needed, consistent with the subsidy treatment described for Scenario 1.

Capital expenditures associated with Scenario 3 include startup costs of $400 thousand and generation investments of $45 million in 2008 and $12 million in 2010.

This supply strategy results in total savings over the study period of $77.5 million or 11% of total electricity costs.

6.2.4 Alternative Supply Scenario 4

Scenario 4 is similar to Scenario 3 except that the portfolio matches the renewable content of PG&E's supply portfolio, with a corresponding increase in the capacity of natural gas fired generation financed by the City.

Capital expenditures associated with Scenario 4 include startup costs of $400 thousand and generation investments of $22 million in 2008 and $16 million in 2010.

This supply strategy results in total savings over the study period of $72.1 million or 10% of total electricity costs.

Comparing the alternative supply scenarios reveals the cost advantage enjoyed by the CCA in financing capital intensive generation projects. The incremental cost of increasing renewable energy from 20% to 40% is not a significant factor in the program's cost-effectiveness.

6.3 Sensitivities

Sensitivity analyses can help put upper and lower bounds on the expected financial results from implementing a CCA program. NCI performed sensitivity analyses for the major variables expected to impact the financial results. The results of these sensitivities are shown below:

- Natural gas and power prices (+/- 25%)
- Cost responsibility surcharges (+/- 50%)
- PG&E system average rate projections (1% to 3% annual growth)
- PG&E revenue allocation changes to reduce cross subsidies (As proposed in its General Rate Case)

None of the sensitivity scenarios eliminated program savings over the study period. However, the GRC rate design scenario (Scenario 8) caused revenue losses in the early years of the program. The City should pay particular attention to changes in this variable if and when it proceeds with implementation of its CCA program. A phase-in of program operations would mitigate exposure to these factors. Another method for accelerating financial benefits would be to create a rate stabilization fund by issuing debt that would be backed by the future revenue streams of the program, thereby moving a portion of future savings forward in time.

Annual financial results associated with the sensitivity scenarios are shown in the following tables.

Scenario 2: Natural Gas And Power Prices Are Reduced By 25% From The Base Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	15.3	17.2	1.9	7%
2007	15.4	17.5	2.1	7%
2008	16.7	18.1	1.4	5%
2009	16.3	18.5	2.2	8%
2010	16.3	18.6	2.2	7%
2011	16.1	19.0	2.9	9%
2012	16.4	19.5	3.1	10%
2013	16.3	18.3	2.0	6%
2014	16.6	18.8	2.1	7%
2015	17.1	19.4	2.2	7%
2016	17.5	19.8	2.3	7%
2017	17.8	20.7	2.9	8%
2018	18.3	22.1	3.8	10%
2019	19.1	23.3	4.2	11%
2020	19.9	24.0	4.1	10%
2021	20.2	24.3	4.1	10%
2022	20.5	24.8	4.3	10%
2023	20.1	24.8	4.7	11%
2024	21.0	26.1	5.1	12%
Total	337.0	394.6	57.6	9%

Scenario 3: Natural Gas And Power Prices 25% Higher Than Base Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	17.4	18.6	1.2	4%
2007	17.8	18.9	1.1	4%
2008	18.3	19.7	1.4	5%
2009	18.8	20.2	1.4	4%
2010	19.7	22.1	2.4	7%
2011	20.5	23.0	2.4	7%
2012	21.2	23.9	2.7	8%
2013	19.3	22.9	3.5	10%
2014	19.9	23.6	3.7	10%
2015	20.9	24.5	3.6	10%
2016	21.3	25.1	3.7	10%
2017	22.3	26.4	4.2	10%
2018	23.7	28.5	4.9	11%
2019	25.0	30.4	5.4	12%
2020	26.3	31.5	5.2	11%
2021	26.6	31.7	5.1	11%
2022	27.2	32.4	5.2	11%
2023	27.2	32.9	5.7	12%
2024	28.7	35.0	6.3	12%
Total	422.1	491.1	69.0	9%

Scenario 4: CRS Is Reduced By 50% From Base Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	14.3	17.4	3.1	11%
2007	14.5	17.7	3.2	11%
2008	15.3	18.4	3.1	11%
2009	15.2	18.9	3.6	12%
2010	16.0	19.9	3.9	12%
2011	16.6	20.5	3.9	12%
2012	17.1	21.2	4.1	12%
2013	16.9	20.1	3.2	10%
2014	17.3	20.7	3.3	10%
2015	18.1	21.4	3.3	10%
2016	18.5	21.9	3.4	10%
2017	19.2	23.1	3.8	10%
2018	20.4	24.8	4.4	11%
2019	21.4	26.3	4.9	12%
2020	22.5	27.2	4.7	11%
2021	22.8	27.5	4.7	11%
2022	23.3	28.1	4.8	11%
2023	23.6	28.9	5.3	12%
2024	24.9	30.6	5.8	12%
Total	357.9	434.5	76.6	11%

Scenario 5: CRS Is Increased By 50% From Base Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	17.9	18.4	0.4	2%
2007	17.9	18.7	0.7	3%
2008	18.8	19.4	0.6	2%
2009	17.8	19.8	2.1	7%
2010	18.3	20.8	2.5	8%
2011	19.0	21.5	2.5	8%
2012	19.6	22.2	2.6	8%
2013	18.0	21.1	3.2	9%
2014	18.4	21.7	3.3	10%
2015	19.2	22.5	3.2	9%
2016	19.6	23.0	3.4	9%
2017	20.4	24.2	3.8	10%
2018	21.5	25.9	4.3	11%
2019	22.6	27.5	4.8	11%
2020	23.7	28.4	4.7	11%
2021	24.0	28.6	4.6	10%
2022	24.4	29.3	4.8	11%
2023	23.6	28.9	5.3	12%
2024	24.9	30.6	5.8	12%
Total	389.7	452.4	62.7	9%

Scenario 6: PG&E Generation Rates Increase At An Annual Rate Of 1% (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	16.1	18.0	1.8	6%
2007	16.2	18.4	2.2	8%
2008	17.1	18.9	1.8	6%
2009	16.5	19.3	2.8	9%
2010	17.2	19.8	2.6	8%
2011	17.8	20.3	2.5	8%
2012	18.3	20.8	2.4	7%
2013	17.4	21.3	3.9	12%
2014	17.9	21.8	3.9	12%
2015	18.7	22.4	3.7	11%
2016	19.1	22.9	3.8	11%
2017	19.8	23.5	3.7	10%
2018	20.9	24.0	3.1	8%
2019	22.0	24.6	2.6	6%
2020	23.1	25.2	2.2	5%
2021	23.4	25.9	2.5	6%
2022	23.8	26.5	2.7	6%
2023	23.6	26.0	2.4	5%
2024	24.8	26.6	1.8	4%
Total	373.8	426.1	52.3	8%

Scenario 7: PG&E Generation Rates Increase At An Annual Rate Of 3% (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	16.1	18.6	2.5	9%
2007	16.2	19.5	3.2	11%
2008	17.1	20.3	3.2	11%
2009	16.5	21.2	4.7	16%
2010	17.2	22.1	5.0	16%
2011	17.8	23.1	5.3	16%
2012	18.4	24.1	5.8	17%
2013	17.4	25.2	7.8	24%
2014	17.9	26.3	8.4	25%
2015	18.7	27.5	8.8	25%
2016	19.1	28.7	9.6	27%
2017	19.8	30.0	10.1	27%
2018	21.0	31.3	10.3	26%
2019	22.1	32.7	10.6	26%
2020	23.1	34.1	11.0	26%
2021	23.4	35.6	12.2	28%
2022	23.9	37.2	13.3	30%
2023	23.7	37.7	14.0	31%
2024	24.9	39.4	14.5	30%
Total	374.2	534.7	160.5	23%

Scenario 8: PG&E's Proposed Revenue Allocation To Customer Groups In Its 2003 General Rate Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	16.1	16.0	(0.2)	-1%
2007	16.2	16.2	0.0	0%
2008	17.4	16.8	(0.5)	-2%
2009	16.5	17.3	0.8	3%
2010	17.1	18.1	1.0	3%
2011	17.8	18.7	0.9	3%
2012	18.3	19.3	1.0	3%
2013	17.4	18.4	1.0	3%
2014	17.9	18.9	1.0	3%
2015	18.7	19.5	0.9	3%
2016	19.1	20.0	1.0	3%
2017	19.8	21.0	1.2	3%
2018	20.9	22.6	1.6	4%
2019	22.0	24.0	1.9	5%
2020	23.1	24.7	1.7	4%
2021	23.4	25.0	1.6	4%
2022	23.8	25.5	1.7	4%
2023	23.6	25.6	2.0	4%
2024	24.8	27.1	2.3	5%
Total	374.0	394.8	20.8	3%

7 EVALUATION OF COSTS AND BENEFITS

This section summarizes NCI's evaluation of the costs and benefits of implementing a CCA program in the City. Evaluation criteria are the ability to deliver lower rates, stable prices, and allowance for increased utilization of renewable energy.

7.1 Ability To Deliver Lower Rates

The economic analysis demonstrates that it is feasible for the City to implement a CCA program. Customers would be able to obtain electric service at rates below those charged by PG&E. Under the most likely scenario, expected savings average 10% of total electric bills over the study period.

Based on the year-by-year financial projections, NCI concludes that electric bill savings opportunities would initially be in the 6 to 7% range and would increase over time. Savings are enhanced by utilization of municipal debt financing of generation projects or long-term power purchases. The cost savings may be sufficient in and of themselves to justify the decision to pursue CCA. The estimated cost savings also help support and justify the decision to pursue CCA to achieve other benefits, such as rate stability, local control, and increased opportunities for renewable energy development.

7.2 Rate Stability

The City could structure its portfolio to emphasize cost predictability and provide stable prices to CCA customers. Long-term supply contracts at fixed prices can provide predictable costs for terms of ten years or longer. Investments in renewable resources, such as wind resources, solar, biomass and geothermal, eliminate the dependence on natural gas and the exposure to fluctuations in natural gas prices for that element of the supply portfolio.

The sensitivity analysis shows an expected range of program savings of between 3% and 23% over the study period. The City's portfolio would demonstrate relatively stable prices to consumers. Under the base case scenario, which reflects very conservative assumptions regarding future increases in PG&E's rates, the CCA program costs are expected to show 17% greater stability than PG&E's rates.

7.3 Increased Utilization Of Renewable Energy

The City would determine how much renewable energy to include in its portfolio, over and above the minimum percentages required pursuant to the

California RPS. The cost of purchasing renewable energy is greater than the costs of purchasing electricity produced from fossil fuels, so exceeding the RPS via power purchases will increase the average cost of the City's portfolio to some degree. However, the analysis shows that doubling the RPS would have only a modest overall impact on customer bills, as discussed below.

7.3.1 Cost Of Renewable Energy

The CEC's Renewable Resources Development Report (RRDR) published in November 2003 shows the mix and costs of the renewable resources that will likely be utilized to meet the California RPS. The cost of buying renewable energy can be estimated by creating a generic portfolio of these resources using the contributions for each type projected in the RRDR study to calculate a weighted average cost. The average cost of these resources, weighted by their expected contribution to the RPS, is shown below:

Renewable Resource Technologies Expected To Fulfill The California Renewable Portfolio Standard (2003 Dollars)
Source: CEC Renewable Development Resource Report

Resource	Portfolio Contribution	2005 Levelized Production Cost ($/MWh)
Wind (Class 4 site)	66%	60 *
Concentrating Solar	1%	121
Landfill Gas	4%	44
Solid Biomass (Direct Combustion)	4%	66
Geothermal (Binary)	25%	55
Weighted Average		59

* The cost of wind is based on the levelized cost of $49 per MWh presented in the RRDR plus an additional $11 per MWh capacity cost to reflect that capacity must be acquired separately because of the intermittency of wind resources. These figures do not include production tax credits, which many people believe will be reinstated once Congress passes a comprehensive energy bill.

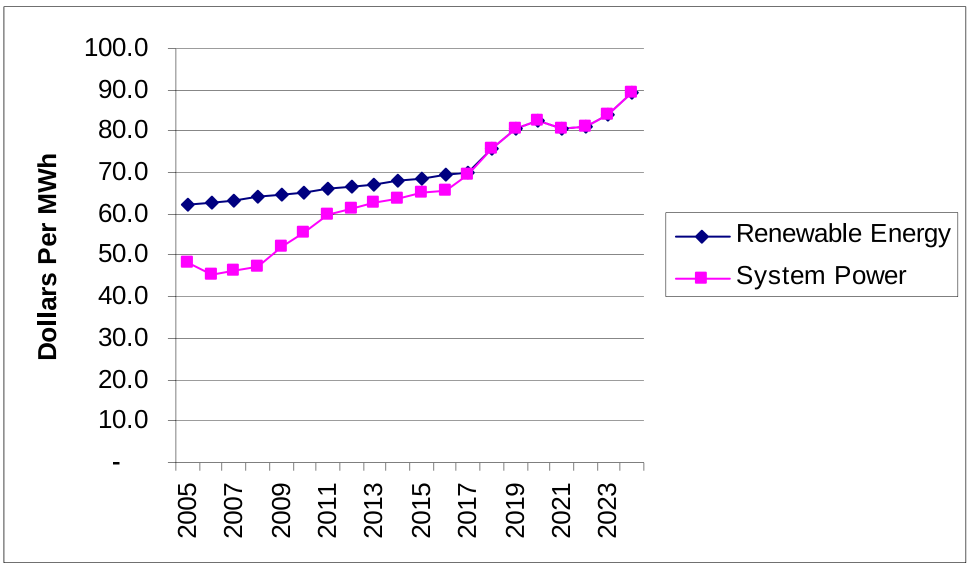
Escalating the cost to 2006 by assuming 2.5% annual inflation yields a 2006 average renewable cost of $62 per MWh. This represents a premium of approximately $18 per MWh above the projected market prices of system power in 2006.

All else being equal and assuming no City capital financing of renewable energy, the cost of doubling PG&E's 14% renewable mix would be $18/MWh * 0.14 =

\$2.52 per MWh. A typical household would pay \$1.26 more per month to double the amount of renewable energy used to supply its electricity consumption.[13] The premium declines over time as natural gas and electricity market prices are expected to rise faster than the cost of renewable energy production. For instance, assuming average annual increases in the market price of system power of 2.8% used in this study, the renewable price premium falls to \$4 per MWh by 2014. By 2018, the market price of renewable energy is expected to be no greater than the cost of conventional generation resources.[14]

The projected costs of renewable and conventional electricity are shown in the following chart:

Northern California Market Price Projections For Renewable And Conventional Electricity



7.3.2 Municipal Financing of Renewable Energy Development

As described in this feasibility study, the City can reduce the cost of acquiring renewable energy by financing development of renewable resources used to supply its CCA program. The following table compares the total cost of a hypothetical 100 MW wind energy project utilizing the financing structures typical of an investor owned utility vs. those available to the City. The

---

[13] Typical residential consumption is approximately 500 kWh or 0.5 MWh per month.

[14] The cost of transmission investments that may be needed to bring large amounts of renewable energy to load centers is not included in this analysis. These costs will be included in transmission rates that are paid by all users of the grid and should not impact the CCA economic analysis.

underlying assumptions are that the utility's capital structure is comprised of 50% debt and 50% equity at an overall cost of capital of 9%, while the City employs 100% debt financing at a rate of 5.5%. The utility is subject to federal and state income taxes of 40.75% so that the tax-effected cost of capital is 12.9%. The City makes no return, has no income tax obligation and establishes its revenue requirement based on the cash requirements needed to cover expenses and debt service.

Cost Comparison – IOU Vs. City Ownership of Wind Resource (Thousand of Dollars)

Cost Element	Investor Owned Utility	City
Capital Cost ($000)	15,951	7,730
Operations & Maintenance ($000)	2,198	2,198
Firming Capacity ($000)	3,022	3,022
Total First Year Cost ($000)	21,171	12,950
Cost Per MWh ($/MWh)	77	47

During the first year of operation, the City can produce energy at a cost that is nearly 40% lower than what the investor owned utility would incur if it owned the identical resource. The City's cost of producing renewable energy would be nearly the same as the market price of system power.

7.3.3 Operational Issues For Renewable Energy

Renewable resources are generally non-dispatchable, operating as either baseload resources or on an as-available basis. Wind and solar resources produce electricity only during certain times of the day when there is sufficient wind or sun. These characteristics place an operational limit on the amount of renewable energy that can be included in the overall resource mix. Depending on a community's load duration curve, which defines its base load requirements, the operational limit could range between 50% and 70%.[15] It would be possible to exceed these amounts by over-procuring, but doing so would require the Aggregator to sell excess energy into the market during many hours of the year, thereby taking on additional risks associated with wholesale sales of energy.

[15] This refers only to the City's program operations and is not intended to imply that the entire system could efficiently integrate such large amounts of renewable energy.

A similar issue exists with reliance on intermittent wind production. If an Aggregator with an average load requirement of 200 MW established a 50% renewable target, it would need approximately 300 MW of wind capacity. With a typical capacity factor of 32%, production from 300 MW of wind capacity would average the 100 MW needed to meet the target. However, at any moment in time, the Aggregator could have between 0 and 300 MW of production. The Aggregator would either need to purchase 200 MW of replacement energy or it would have 100 MW excess energy to sell. These imbalances impose financial risk on the Aggregator as the prices at which it must buy and sell energy may not be identical.

One way that the CCA could safely exceed the operational limits on renewable energy is by purchasing renewable energy certificates (RECs) from producers of renewable energy. The CEC is currently investigating a system that would facilitate trading of RECs, and private markets for RECs have been in existence for several years. The tradable REC concept allows the renewable attribute associated with renewable energy production to be sold separately from the electrical energy. Through appropriate tracking and verification, the buyer can be assured that for each REC purchased a kWh of renewable energy was produced during the year; however, the renewable production need not match the buyer's load requirements on an hour-by-hour basis. By separating the renewable attribute from the electrical energy, a CCA could ensure that enough renewable energy was produced over the course of the year to supply 100% of its customers' load requirements, while avoiding the need to sell excess energy. The price of the REC should be approximately equal to the cost difference between the market price for system power and the cost of renewable energy production, after considering all available incentives.

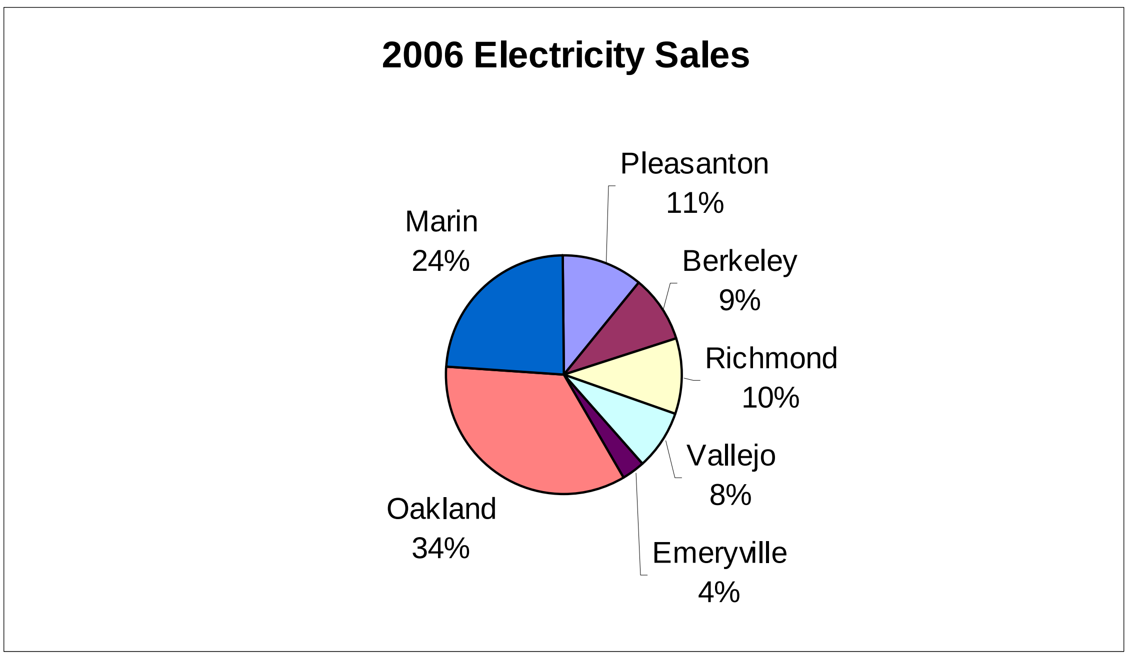
8 REGIONAL COMMUNITY CHOICE AGGREGATION PROGRAM OPERATED UNDER A JOINT POWERS AGENCY

8.1.1 Economies Of Scale From Combined CCA Operations

By combining the electric loads of multiple cities and/or counties for CCA operations, scale economies can be achieved that increase the benefits available to the individual members. Operational cost saving can be captured through common program administration and energy procurement activities. Diversity among community load shapes enables the sharing of capacity reserves, lowering overall procurement costs. The flatter load shape of a combined CCA program reduces the costs of serving the load, thereby increasing the benefits available to each of the participating communities.

NCI performed a financial assessment of combining the seven Bay Area communities participating in the CCA demonstration project for purposes of a common CCA operation. The Bay Area participants are listed below along with the shares of 2006 electricity sales.

Bay Area Participants In The CCA Demonstration Project



Annual financial results of a joint program are shown below.

Bay Area CCA Program Financial Summary (Millions of Dollars)

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	296.4	22.8	4.5	102.7	4.1	1.5	432.0	457.8	25.8	3%
2007	303.0	23.6	4.5	97.1	4.2	1.6	434.0	465.8	31.8	4%
2008	296.0	24.6	4.5	98.9	4.4	33.9	462.3	483.3	21.0	3%
2009	305.4	26.6	4.5	69.8	4.6	33.7	444.5	495.3	50.8	6%
2010	334.5	28.3	4.5	64.2	4.8	39.9	476.1	520.8	44.7	5%
2011	345.5	30.2	4.5	66.0	5.0	39.4	490.7	537.5	46.8	5%
2012	355.6	31.5	4.5	68.1	5.1	38.9	503.7	555.9	52.1	6%
2013	298.9	32.7	4.5	30.4	5.4	88.7	460.5	527.6	67.0	7%
2014	311.5	33.9	4.5	30.8	5.6	87.4	473.6	543.0	69.4	7%
2015	341.8	35.3	4.6	31.3	5.8	86.0	504.6	562.3	57.7	6%
2016	353.7	36.3	4.6	31.7	6.0	84.5	516.8	576.2	59.4	6%
2017	369.8	38.4	4.6	32.2	6.3	83.0	534.1	605.3	71.2	7%
2018	393.5	41.4	4.6	32.7	6.5	81.4	560.1	649.6	89.6	8%
2019	417.0	44.2	4.6	33.1	6.8	79.8	585.5	690.2	104.7	9%
2020	459.5	45.8	4.6	33.6	7.0	78.0	628.5	713.3	84.8	7%
2021	471.1	46.4	4.6	34.1	7.3	76.0	639.5	719.8	80.3	7%
2022	486.8	47.7	4.6	32.9	7.6	73.9	653.5	736.4	82.9	7%
2023	509.7	50.1	4.6	-	7.9	71.8	644.2	739.5	95.4	7%
2024	538.4	53.1	4.6	-	8.2	69.6	674.0	784.5	110.5	8%
Total	7,187.8	692.9	86.6	889.6	112.4	1,148.9	10,118.3	11,364.2	1,246.0	6%

A combined operation would yield over $300 million in additional financial benefits during the study period compared to the benefits achievable through individual CCA operations. This represents a 34% improvement in financial benefits from joint operation.

8.1.2 Joint Powers Agency Structure Option

Joint Power Agencies (JPA) are common legal structures that many public agencies have formed and used to offer services in a more economical and efficient manner. CCA JPA formation can combine city and county jurisdictions to secure long-term power contracts or development its own generation resources. Multiple member CCA JPAs may benefit from smoother electric load shapes, reducing the overall cost to serve. There are numerous operating examples of jurisdictions forming JPAs to procure electric energy in wholesale markets for delivery to member constituent retail markets. The following describes some of the benefits and impediments of the CCA JPA structure option:

<u>Summary of Benefits</u>

- The JPA structure enables its party agencies to jointly exercise any power common to them. CCA enabling legislation cites eligible jurisdictions as cities, counties or JPAs comprised of cities and counties.

- The CCA JPA will be a non-profit agency and its motives are not profit driven.
- Parties to the JPA would share cost/risk and assist with any JPA project.
- JPA formation can combine its members in securing long-term power contracts or entering into agreements with agencies in the development of generation resources.
- JPA members could benefit from economies of scale associated with building a large project with its greater plant efficiencies and lower unit costs.
- The JPA may authorize the issuance of low cost bonds by ordinance subject to referendum but without a vote of the electros within the public entities comprising the JPA
- A JPA provides a organizational, legal and financial structure to integrate its parties and facilitate the implementation and operation of projects (in this case utilities)
- This structure minimizes direct exposure of the member jurisdictions and at the same time provides a conduit to key capital, political, and intellectual resources for the other JPA members.
- This structure could reduce or eliminate the need for redundant personnel and systems to facilitate energy supply for the multiple member jurisdictions.
- JPA Operational Business Plans could incorporate phased customer segment participation and provide flexibility to subcontract the organizational depth needed during initial CCA operation.

<u>Summary of Impediments</u>

- Forming a JPA is time consuming; It is necessary to establish a working group or advisory panel of all parties, and parties must agree on approach and structure (the fewer the parties the more streamlined the process).
- The challenge for governance is to provide equitable representation for both large and small members without compromising either's options.
- The decision-making process can be cumbersome, during both formation and operation (decisions tend to be "consensus" driven, slowing processes and compromising positions - members seek to protect their own interest).

8.1.3 Purpose and Parties

A JPA is formed when it is to the advantage of two or more public entities with common powers to consolidate their forces to acquire or construct a joint-use facility or when local public entities wish to pool with other public entities to save costs to acquire equipment or to acquire or construct facilities for their individual use. A joint exercise of powers agreement must be approved by all participating entities, and this may include the federal government or any federal department or agency, this state, another state or any state department or agency, a county, county board of supervisors, city public corporation, or public district of this state or another state.

8.1.4 Authorization

A Joint Powers authority is empowered by Chapter 5, commencing with section 6500 of Division 7 of Title 1 of the Government Code, to issue bonds, notes, Commercial paper, including certain kinds of variable rate securities for specified purposes, and to enter into leases to acquire land and equipment or to acquire or construct public facilities. The JPA entity is created when member jurisdictions enter into a joint exercise of powers agreement, forming a joint powers agency and by adopting identical concurrent, ordinances.

8.1.5 JPA Governance

A commission responsible for administering the CCA JPA would be established comprised of representatives from each party to the CCA JPA Joint Powers Agreement. A quorum of the CCA JPA Commission (Commission) would consist of those Commissioners, or their designated alternatives, representing a numerical majority of the Parties. Voting on JPA actions could be facilitated wherein each Party would have the right to cast one vote. In the alternative, voting may be conducted where each party has a number of votes equal to its percentage share of CCA JPA expenses. Such procedures would be developed by a working group or advisory panel of all parties as referenced above.

In addition to voting representation on the Commission, flexibility for Parties to take actions alone or in concert other selected JPA members, and thereby ensure members can protect and pursue individual interests, can be facilitated through the development and use of a hierarchy of structured agreements. In the example below, precedence of agreements can be established where, for example, a Project or Operating Agreement takes precedence over a Facilities Agreement. In this case action can be taken by JPA members without executing a higher-level membership-wide agreement. In this way specific operational arrangements between a limited numbers of Parties take "precedence" over higher-level membership-wide agreements. The names and use of agreement structures would be adjusted to more closely reflect CCA JPA activities. The following is an example of hierarchical of JPA Agreements used by the Northern California Power Agency:

Agreement Hierarchy:

1. Joint Powers Agreement
2. Pooling Agreement
3. Facilities Agreement
4. Project Agreement
5. Operating Agreement

Joint Powers Agreement: Through the Joint powers Agreement a CCA might be established as a public agency pursuant to the Joint Exercise of Powers Act of the Government Code of the State of California authorized to acquire, construct, finance and operate buildings, works, facilities and improvements for the generation of electric capacity and energy for resale. Each of the Parties to the Agreement would be a city or a county jurisdiction authorized to implement a CCA pursuant as defined in enabling legislation AB 117 (Migden – Chapter 838, Statutes of 2002).

Pooling Agreement: Each Party to the Pooling Agreement is a Party to the CCA Joint Powers Agreement. The Pooling Agreement establishes facilities, staff, and the capability for: Planning for the addition of facilities; entering into long-tem and short-term, firm and non-firm interchange transactions; dispatching and scheduling all available resources to meet the combined loads of the Parties.

Facilities Agreement: A Participant in an CCA Facilities Agreement is an CCA JPA member and a signatory to the CCA Joint Powers Agreement (JPA). The Facilities Agreement provides a framework for membership joint design, construction and operation of power supply facilities.

Project Agreement: Establishes the framework for the development, design, financing, construction and operation of specific projects.

Operating Agreement: Detailed descriptions, principles and procedures (including operating and cost recovery) for CCA JPA projects.

8.1.6 Revenue Bond Issuance

The JPA may authorize the issuance of revenue bonds by ordinance subject to referendum but without a vote of the electors within the public entities comprising the JPA. However, JPAs may also issue securities pursuant to a resolution of the authority backed by loan agreements and/or bond purchase agreement with participating member agencies. The law provides that some but not all of the members of a JPA may participate in a bond issue and that only those participating will be obligated to repay the debt incurred.

Below we list a number of financing alternatives to consider once a JPA has been formed.

Figure 12

Comparative Features of Alternative Financing Methods

Financing Method/Characteristics	General Obligation Bonds	Limited Obligations Bonds	Special Assessment	Certificates of Participation	Revenue Bonds
Project Financeable	Acquisition & improvements of land and buildings	Acquisition & improvements of land and buildings	Facilities of local benefit to property	Unrestricted	Revenue producing facilities
Authorization	Issuer's governing board & public election (2/3 vote)	Resolution of issue governing board and 2/3 vote	Resolution of issuer, petition of beneficiaries	Resolution of issuer governing board	Resolution of issuer governing board
Area of Authorization Jurisdiction	Boundary of issuer facilities district (flexible)	Boundary of issuer facilities district (flexible)	Flexible	N/A	Service area of issuer
Hearing Procedure	None	None	Majority protest hearing	Maybe ordinance adoption	None
Validation	None	None	None	None	None
Nature of debt service payments	Unlimited ad valorem tax	Portion of current revenues	Annual assessments based on benefits received; property taxes may not be used	Rental or installment payments	Service charges and fees from users
Source of debt service payment	Property owners in issuer jurisdiction	General revenues of issuer	Annual property assessments	General &/or enterprise revenues of issuer	Service charge and fee collections
Security	Full faith and credit	Revenue collections and coverage test	Tax collections/ Foreclosure	Lease or installment sale contract	Coverage test and contracts
Lessor/Lessee Required	No	No	No	Yes	NO
Refundable	Yes	Yes	Yes	Yes	Yes
Debt Service Funds subject to Gann Limit	No	No	No	Yes	Yes
Structural Features					
Reserve Fund	No	Yes	Yes	Yes	Yes
Capitalized Interest	No	No	Yes	Yes	New enterprise only
Debt Service Coverage	NO	Yes	Value/lien ratio 3:1	No	Yes
Method of Sale	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated
Advantages	Lower interest rate	No pledge of General Fund	Isolates projects	No voter approval	Higher interest rate
Disadvantages	Voter approval required	Voter approval	Limited security Higher interest rates	Highly structured Limited flexibility	Debt Service Reserve Fund

The overview above provides a broad perspective on the various financing techniques that will be available to a CCA JPA. However, the ultimate method that the CCA JPA chooses will be based on a number of factors:

Purposes of Financing: Proceeds of the financing can be used for a number of different uses including but not limited to: Start-up costs, construction of new plant and equipment, initial capital for power purchases, Operations and maintenance expenses among others. As outlined above, the purpose of the financing can and will affect the type of bond issue that the CCA JPA can utilize to finance its various costs. In the end the JPA may execute a series of different products to meet each of its various purposes.

Tax Eligibility: An important consideration in determining the appropriate technique will depend largely on the tax-exempt eligibility of the potential financing. As all the objectives (i.e. purposes and uses of the proceeds) of the specific financing become known, NCI along with counsel for the JPA will have a better sense as to whether the JPA will be eligible to issue tax-exempt bonds. We will obviously attempt to create a structure that maximizes the use of tax-exempt bonds which will ultimately provides the lowest cost of financing to the JPA.

9 CONCLUSIONS AND RECOMMENDATIONS

9.1 Conclusions

There are three general criteria, as described under Section 5, for assessing benefits of CCA. These are the potential for reduced rates, the ability to increase utilization of renewable energy, and enhanced local control/rate stability. This analysis shows it is possible to achieve each of the three objectives by forming a CCA program, under the most likely scenarios. Formation of a CCA program offers benefits but is not entirely without risks, both financial and political. The City should clearly define its reasons for pursuing CCA so that program implementation reflects and fulfills clearly defined objectives. These reasons could include one or more of the following goals:

- Proactively address energy and infrastructure issues in the community
- Expand use of renewable energy resources and increase energy efficiency (e.g., reduce greenhouse gas emissions, reduce dependence on fossil fuels and imported natural gas)
- Reduce energy costs or enhance general fund revenue
- Provide for electric rate stability and local control
- Provide other utility services, such as energy efficiency and distributed generation
- Increase the tools available for economic development and planning
- Position City for provision of expanded electricity service offerings in the future

Ultimately, a primary benefit of CCA is giving consumers greater control over their energy choices and devolving responsibility for energy planning to the local level. The City should take a long-term view in considering the decision to form a CCA program and be prepared to weather challenges that may arise in the short-term. Participation in a regional CCA program via formation of a joint powers agency would offer benefits of scale that would not be available under a standalone program. The City should explore opportunities for joining with other local governments in the region to form a regional CCA program if the City decides to move forward with implementation.

Lower Rates

The analysis indicates the City is likely to obtain cost savings equal to over $3.7 million per year or approximately 10% of customers' electricity bills on average over the study period. These cost savings could be used to reduce rates and/or to create a new revenue stream for the general fund. The scenario analysis shows that savings are not dependent upon the specific financial assumptions underlying the base case. The average program savings range from a low of 3% to a high of 23% across the eight scenarios evaluated to test the sensitivity of these results to changes in wholesale energy market conditions, PG&E rate projections, and cost responsibility surcharges. A conservative interpretation of these findings suggest that over the next several years there would be attractive cost benefits from implementing a CCA program, even after considering the imposition of cost responsibility surcharges on CCA customers. Cost benefits will be more significant over the longer term as the CRS begins to decline and eventually expires.

Increased Renewable Energy

The analysis shows that a 50% renewable energy target can be achieved with no rate increases for customers if the City is willing to finance renewable resource development to supply the CCA program. The cost effectiveness of increasing renewable energy utilization to this degree is greatly enhanced by the involvement of the public sector through CCA because of the public sector's access to low cost capital and the contract coverage afforded by the CCA's large customer base. A primary benefit of forming a CCA program is to create the ability to increase utilization of renewable energy. The realistic implementation approach used in this feasibility analysis incorporates a hybrid supply strategy and gradual ramp-up of renewable energy utilization, initially utilizing contracts with third parties to match the PG&E renewable energy mix and eventually progressing to municipal ownership/financing of generation.

Local control/rate stability

Ultimately the long-term benefits of a CCA program in the community resolve around local control. Such control includes the ability for the City and aligned agencies to effect resource planning and infrastructure investment in an integrated fashion responsive to the community's needs and values. Local control also manifests in avoiding the cost consequences of the utility's long-term procurement decisions, which must be made considering the competing interests of shareholders, regulators, and consumers. The City faces no such conflicts and can focus on its primary mission of representing the interests of consumers.

9.2 Recommendations

1. Communicate final study results through community workshops and identify next steps in proceeding toward Implementation Plan filing.

2. Consider whether natural alliances exist among neighboring communities, and explore partnering arrangements to optimize supply side alternatives and regional CCA implementation.

3. Make decision whether to proceed with development of an Implementation Plan.

APPENDICES

Appendix A – Resource Portfolio Planning Template

Fifth Supply Scenario Variables

1. Renewable Energy (RE) Targets
    a. End-State Percentage (20-100% by 2017) ________
    b. RE Ramp Rate 2006 – 2023, Cite Yearly Targets
        1) 2006 min. 14%
        2) 2017 min. 20%
    c. RE Equity Position
        1) Physical Resource Entitlement (ownership/investment)
            a) Yes __ No __
            b) Percentage of Total RE __
            c) In-Service Dates and Capacities (MW)
        2) Market Purchases
            a) Percentage of Total RE __
            b) Contract Schedule and Capacities (MW)
2. Conventional Generation Resource Equity Position
    a. Physical Resource Entitlement (ownership/investment)
        1) Yes __ No __
        2) In-Service Dates and Capacities (MW)
    b. Market Purchases - Contract Schedule and Capacities (MW)
3. Distributed Generation
    a. Capacity (kW)
        1) Existing
            a) Technology (PV/micro-turbine/etc)
            b) Capacity (kW)
            c) Energy (kWh)
            d) Cost
            e) In-Service Dates
        2) Planned
            a) Technology (PV/micro-turbine/etc)
            b) Capacity (kW)
            c) Energy (kWh)
            d) Cost
            e) In-Service Dates
4. Spot Market Purchases (assumed minimized – under 15% energy unless instructed otherwise)
5. Based Upon the 5th or "Preferred" Supply Portfolio Sensitivities Will be Assessed for the Following Variables:
    a. Natural gas/power prices (+/- 25%)
    b. Cost responsibility surcharge (+/- 25%)

c. IOU rate projections (+/- 5%)
d. IOU rate design (GRC proposals)
e. Renewable subsidies (SEP, PTC)
f. Combined operation with other Project participants

Appendix B – Detailed Assumptions

Key Assumptions Used In CCA Feasibility Analysis and Modeling - Pacific Gas & Electric Territory

1) Metering and Billing

   a) No new metering requirements for CCA customers.
   b) Billing charges same as direct access from Schedules E-ESP and E-EUS.
   c) Billing charges based on Rate-Ready Billing Option from Schedule E-ESP.

2) Financing

   a) Tax exempt financing for startup costs and any new generation development @ 5.5%.
   b) 100% debt financing.
   c) Financing term is 30 years.
   d) Minimum debt coverage ratio of 1.25.
   e) Bond insurance cost of 1.6% of par value.
   f) Bond transaction cost of 1% of par value.
   g) Debt reserve of 10% of par value.

3) Startup and Operations Costs

   a) Startup costs include regulatory and legal @ $350,000.
   b) Operational costs are outsourced @ $2.50 per MWh unless and until CCA reaches approximately 1.5 million MWh in sales.
   c) If performed internally, the cost is estimated at $3.9 M per year plus 10 cents per MWh, including IT.
   d) Activities include scheduling coordination, procurement/planning, risk management, credit, rates and load research, A&G, and IT.
   e) The CCA will begin serving customers in January 2006

4) Resource Adequacy

   a) CCAs subject to same resource adequacy requirement as IOUs, per D.04-01-050.
   b) Planning reserves are required to bring total reserves, including ISO required ancillary services, up to 15% of peak load.
   c) Costs of meeting planning reserves equal to market value of capacity.

d) Spot market purchases limited to between 5% and 20% of CCA portfolio; the remainder of the portfolio is comprised of long-term contracts and/or resource ownership.

5) Renewable Energy Portfolio

a) Renewable purchases are from a generic portfolio comprised of Class 4 Wind, Binary Geothermal, Solid Fuel Biomass, Land Fill Gas Biomass, and Concentrating Solar Power.
b) The cost and resource mix comprising the portfolio is derived from the CEC's Renewable Resources Development Report (11/7/03) See RRDR, Table 4, page 37 and discussion at page 87. 2005 costs are escalated at a nominal rate of 1% per year.
c) The cost of the generic renewables portfolio equals the estimated developers' costs, including return on investment. Market price of renewable energy equal to maximum of cost or market price of system energy
d) The cost of wind energy assumes no extension of the production tax credit.
e) Wind energy must be firmed via capacity contracts due to its intermittent nature. The cost of wind energy is adjusted for a capacity adder to firm the intermittent resource, at market value of capacity.
f) Renewable ownership costs are derived by applying municipal financing assumptions to the cost data in RRDR Appendix D, page D-6. 2005 costs are escalated at a nominal rate of 1% per year.
g) Ownership cost incorporate technology specific assumptions regarding installed capital costs, fixed operations and maintenance, capacity factor, fuel cost, and capacity cost adder applied to intermittent resources.
h) The ownership costs of intermittent resources also includes a risk factor of $5 per MWh related to the potential differences between energy prices for sales from excess production versus purchases for production shortfalls.
i) CCAs will rely primarily on large-scale renewable projects to meet and exceed the RPS. These are Wind, Geothermal, Solid Fuel Biomass, and Concentrating Solar Power.
j) CCA owned generation resources can be online by 2008.
k) Distributed generation options, such as rooftop PV systems, are incorporated in the feasibility analysis based on community specific planning. Renewable DG production, if any, will be in addition to the RPS minimums.
l) Supplemental energy payments are available to offset the incremental costs of renewable contract purchases (10-Year Terms) up to the minimum RPS requirement. PGC funds are sufficient to buy down 100% of the cost premium of renewables.

m) Supplemental energy payments are not available for city-owned resources and not available for purchases in excess of the RPS minimums.
n) CCAs are required to match the renewable energy percentage of the respective investor owned utility in the first year of CCA operations.
o) IOU renewable baseline percentages are derived from RRDR Appendix A, page A-2 and increased by 1% per year until 20% is achieved by 2017.

6) Wholesale Energy Markets

a) Electricity market price forecast based on projected market clearing system heat rates and natural gas price projections.
b) Natural gas price projections prepared by NCI in January 2005.
c) Implied system clearing heat rates for 2005-2010 are 8,000, 8250, 8700, 9000, 10,000, 10,500. Market equilibrium assumed at implied system heat rate of 11,000 after 2010.
d) On-peak energy priced at 15% premium; off-peak energy priced at 15% discount; real time energy at 10% premium.
e) Long term contracts priced at 5% premium to expected spot market prices.
f) Capacity costs valued at $100,000 per MW-Year, escalated at 2.5% annually; costs are embedded in energy prices derived as above.
g) Ancillary services and related costs estimated based on historical relationship to market prices, projected forward.
h) Ancillary services requirements based on percentage of CCA's load per current CAISO practice.
i) Ancillary services types are Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve.
j) California Independent System Operator (CAISO) administrative and neutrality charges are derived from current rates, escalated at 2.5% annually.
k) CAISO charges are Grid Management Charge - Control Area Service, Grid Management Charge - Inter-zonal Scheduling, Grid Management Charge - Ancillary Services and Real Time Operations, Unaccounted For Energy Charge, Neutrality Charge, Congestion Charge, De
l) No explicit modeling of impact from move to locational marginal pricing; assumed that loads will be protected from congestion costs by allocation of congestion revenue rights and zonal averaging of prices.
m) Distribution losses are 7%.

7) Generation Cost
a) CCA's choosing to own generation will acquire equity interests in combined cycle gas turbine facilities based on the following cost and operating parameters:
b) Installed cost of $700 per KW.

c) Heat rate of 7,000 mmbtu/MWh.
d) $3 per MWh fixed and variable O&M
e) 0.1 pounds per MWh emissions..
f) $10 per pound cost of NOx emissions.
g) 90% planned capacity factor.
h) 2% forced outage rate.
i) Excess sales sold at prevailing market clearing prices.

8) <u>Cost Responsibility Surcharges</u>

a) Cost responsibility surcharges calculated annually using total portfolio indifference method adopted in direct access proceeding (includes old and new resources) (R.02-01-011) and CCA Rulemaking (D.04-12-046)
b) CRS reduced by pro rata share of cost of ancillary services and planning reserves
c) No cap on cost responsibility surcharge for CCAs.
d) Cost responsibility surcharge includes DWR bonds, DWR power charge, utility CTC, and Regulatory Asset.
e) Uniform "indifference fee" per KWh for all CCA customers, regardless of rate class and CCA startup date. No baseline credits reflecting AB1X protections for residential consumption up to 130% of baseline allocation.
f) Uniform DWR bond charge per KWh, statewide.
g) CTC rate varies by customer class based on current tariffs.
h) DWR bond charge projections based on currently applicable rate as of January 2005.
i) No transfer to CCA of DWR contracts, renewable energy, or capacity contracts implied by payment of cost responsibility surcharges.

9) <u>IOU Rate Projections</u>

a) IOU rates for generation are the competitive reference point for assessing CCA cost savings potential.
b) Current IOU rate schedules (Advice Letter 2570-E-A) as of January 2005 applied to CCA customer billing determinants (estimated), aggregated by major rate group.
c) Generation rates and total rates (generation plus non-generation) projected forward based on percentage changes in IOU system average rates.
d) IOU generation costs projected based on current resource mix, adjusted over time for planned generation retirements, DWR contracts, QF contracts, and renewable energy contracts to meet RPS.

e) PG&E owned generation resources includes Nuclear (Diablo Canyon), Hydro, and Fossil facilities. Production and sales data are from PG&E's Long Term Resource Plan.
f) Generation costs and beginning rate base for each generation type are derived from 2003 General Rate Case filing.
g) Generation costs include operations and maintenance, return, depreciation, uncollectibles, A&G, franchise fees, taxes other than income, taxes based on income, fuel, thermal decommissioning, and other.
h) Future capital additions increased for Diablo Canyon turbine replacement anticipated in the 2007 - 2009 timeframe.
i) Purchased Power includes QF contracts, existing bilateral contracts, DWR contracts, new renewable contracts, new bilateral contracts, and spot market purchases.
j) New bilateral contracts entered into as needed to maintain spot purchases (residual net short) at or below 10% of IOU portfolio.
k) PG&E maintains planning reserves of 15% of annual peak load. Existing ancillary services requirements are included in the 15% planning reserves requirement.
l) Spot market purchases to meet the residual net short are priced at average of NP15 peak (6 X 16) and base (7 X 24) power prices.
m) Majority of QFs (80%) paid according to settlement price through 2005, and then based on annual short run avoided cost formula.
n) QF capacity payments derived from FERC Form 1 data.
o) QF capacity/energy projections derived from the Consultant's Report supporting DWR bond financing.
p) RPS purchases from generic renewable portfolio as described above; Supplemental Energy Payments fully offset incremental costs relative to non-renewable energy.
q) DWR costs and volumes adjusted over time based on terms of the individual contracts allocated to PG&E per D.02-09-053.
r) DWR "remittance rate" calculated using CPUC methodology (D. 04-12-014).
s) Regulatory asset cost calculated based on terms of approved Bankruptcy Settlement.
t) Cost offset for bundled customer generation costs from cost responsibility surcharges paid by Direct Access Customers based on capped collection rate from direct access proceeding (R.02-01-011)
u) Non-generation costs escalated at constant 1.5% per year. Non-generation rates are only used to express the CCA cost impacts as percentage of customers' total electric bills.
v) Same input assumptions as above for wholesale electricity prices, capacity prices, natural gas prices, ancillary services costs, CAISO charges, RPS % and prices, supplemental energy payments, and DWR bonds charges.

Appendix C – Sample Data Request Letter

[DATE]

Pacific Gas & Electric Company

Governmental Affairs

Attention: [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE]

77 Beale Street

San Francisco, CA 94105

SUBJECT: Information Request Per D.03-07-034

Dear [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE]:

The [CITY OR COUNTY] of [NAME] (CITY OR COUNTY) is currently reviewing its options in becoming a Community Choice Aggregator (CCA) in accordance with AB 117, enacted in 2002, for: 1) administering energy efficiency programs; and 2) possibly providing electrical energy as related to this legislation. On July 10, 2003, the California Public Utilities Commission (CPUC) approved an "Interim Opinion Implementing Provisions of Assembly Bill 117 Relating to Energy Efficiency Program Fund Disbursements" (Decision 03-07-034). As part of this Decision, the CPUC directed Pacific Gas & Electric Company (PG&E) to provide certain types of information to cities, counties, and CCAs.

The [CITY OR COUNTY] respectfully requests the information listed below, as enumerated in Attachment C of D.03-07-034 for all electric customers within the [CITY OR COUNTY].

1. Energy consumption for each customer class for a given period of time and a given city.

    The [CITY OR COUNTY] requests the total number of customers and monthly energy consumption in kWh for the following rate groups: residential (E-1 and all other residential services), small commercial (A-1, A-6) medium commercial (A-10), small industrial (E-19), large industrial (E-20), agricultural, and outdoor and street lighting. Please provide the above information separately for customers currently receiving bundled utility service from PG&E and customers currently served under direct access arrangements with energy service providers.

2. System-wide residential and nonresidential load shapes and most recent hourly load shapes for the climate band encompassing the [CITY OR COUNTY].

3. The proportional share in the potential CCA territory, as defined in the Commission's energy efficiency policy manual.

The [CITY OR COUNTY] understands that D.03-07-034 ordered that PG&E "shall provide the information and data described in Attachment C to any city, county or CCA that requests it, as set forth in this order without charge." We also understand through this Decision that this information "should be provided…within one week of the request."

Please send this information in electronic form via e-mail to [E-MAIL ADDRESS]. If you have any questions regarding this request, please contact [NAME] at [TELEPHONE]. The [CITY OR COUNTY OF NAME] appreciates your assistance.

Sincerely,

[NAME]
[TITLE]
[CITY OR COUNTY NAME]

Appendix D – CCA Functional Elements

The operations of a CCA program include all activities needed to procure electricity for end-use customers, schedule delivery of the electricity, conduct financial settlements for wholesale electricity purchases and sales, determine the costs charged to individual customers, and interface with PG&E which would provide billing, metering, and customer services to CCA customers. These activities can be grouped into the broad categories described below.

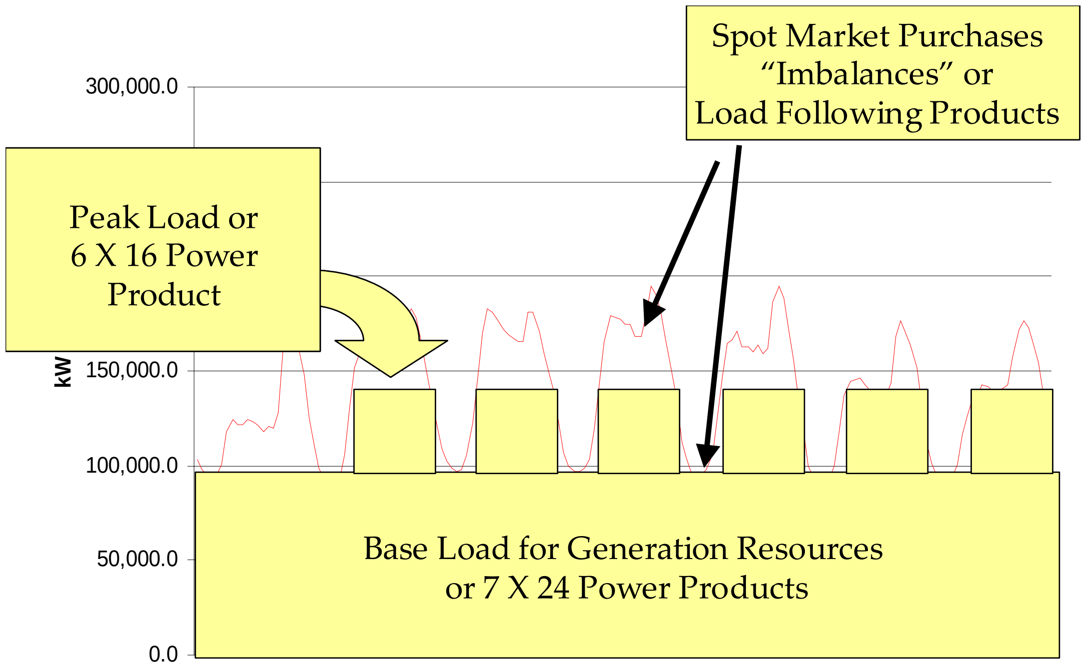
1. Portfolio Operations

Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end-use customers. These activities are virtually identical to the supply functions performed by local utilities, municipal utilities, and energy service providers.

   a. Electricity Procurement

The essential purpose of the Aggregator is to assemble a portfolio of electricity supply sources on behalf of its customers. As an Aggregator, the City can choose from various types of resources and wholesale electricity products to achieve a supply portfolio that appropriately reflects the desired balance of cost certainty, environmental considerations, cost effectiveness, and operational and contractual flexibility.

A variety of generation resources or electricity purchase contracts can be employed to provide for the time-varying load requirements of the CCA program. The pattern of aggregate electricity usage typically follows daily, weekly and seasonal cycles, peaking during the afternoon hours and the summer months. The City must consider these load patterns when assembling a supply portfolio to properly match resources to the aggregate load shape of its customer base. Different types of generation resources and supply contracts supply the base load requirements, intermediate resource needs, and peaking load requirements. These concepts are illustrated in the following diagram.



A typical supply portfolio would utilize generation owned by the City or long-term contracts for the majority of projected base load requirements. These base load resources would be supplemented with intermediate resources or peak products as well as short-term contracts covering the additional seasonal load requirements of the portfolio, typically in the third quarter of each year. Spot market purchases and sales are used to fill the residual "net short" load requirements.

b. Risk And Credit Management

Risk management techniques would be employed to reduce the City's exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices. Credit monitoring is also important to keep abreast of changes in a supplier's financial condition and credit rating. Common practice in the energy industry is to periodically calculate the financial exposure to a supplier by comparing the value of the supply contract to the contractual price, utilizing so called "mark-to-market" valuation. Exposure to suppliers is greatest when the contractual price is low relative to prevailing market prices, and the risk of default becomes a concern. Collateral and other security instruments, such as letters of credits or surety bonds, are commonly used to manage credit risks between wholesale electricity buyers and sellers.

c. Load Forecasting

In performing the electricity procurement functions, it is necessary to develop accurate load forecasts, both long-term for resource planning and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.

The CCA will be required to purchase energy on the wholesale market for each hour of the day. To support financial settlements and energy procurement, an accurate record of total, time-of-day specific electricity demand and energy usage is essential. Lacking this, the CCA operator is required to rely on the distribution utility's recorded usage for each individual customer. All customer classes are not metered in the same way. In particular, residential and small commercial consumers (electric demand less the 20 kW) typically have simple electro-mechanical meters capable of metering only cumulative energy consumption. Medium commercial customers (electric demand in the range of 20 to 500 kW) are typically metered with energy and demand meters, but still lack time-of-day recording. Large commercial and industrial customers (electric demand greater than 500 kW) are typically equipped with data recording meters recording electric demand on five, ten or fifteen minute intervals (interval data recording meters or IDR).

Without a time-of-use record of energy consumed, the City will have to rely on prototypical rateclass load profiles. The California Independent System Operator (CAISO) allows use of load profiles that are approved by the local regulatory agency (CPUC) for scheduling and settlement. These *load profiles* are derived by distribution utility load research based on IDR metering of a stratified random sample from each rateclass (residential, small commercial, medium commercial, industrial). Hence, they represent the average or typical customer and not the CCA's actual customers. To date, the CPUC has approved the use of rateclass load profiles for use by the utilities and energy service providers for electricity scheduling and settlement. The local utilities have opposed proposals made in R.03-10-003 that Aggregators be allowed to use area-specific load profiles for these purposes.

CCAs have the option, under the law, to meter electricity supplied to the jurisdictional territories comprising the CCA to obtain an accurate record of aggregated loads. PG&E is required to "install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the CCA's political boundaries" at the request and at the expense of the CCA. PG&E will also be required to "read the metering devices and provide the data collected to the CCA at the aggregator's expense."[16] Utilities are directed under CPUC Order Instituting Rulemaking R.03.09.007 (August 21, 2003) to develop specific tariff language to meet the requirements. Assessing the size, type, location, quantity and installation cost of such CCA wholesale metering will require an analysis of PG&E's distribution system, in concert with utility Service Planners, and, will require PG&E to comply with the CPUC's Order to develop applicable tariff terms and conditions. At this time, it is not clear to what extent the CPUC or the CAISO would have to approve the City's use of boundary meters for electricity scheduling and settlement.

d. Scheduling Coordination

Scheduling coordination costs are the costs associated with scheduling and settling electric supply transactions with the CAISO. All customer meters must be represented by a CAISO-certified scheduling coordinator. The scheduling coordinator submits schedules to the CAISO of hourly electric demands and supply resources on behalf of the City. The scheduling coordinator is responsible for costs associated with imbalances or deviations between the actual hourly loads and the actual hourly production of the resources it represents. It is also responsible for the costs of reserves and other services ("ancillary services") provided by the CAISO that are needed for reliable operation of the transmission system.

The City has several choices for obtaining services of a scheduling coordinator. Some companies act as independent scheduling coordinators and charge service fees for their services. Other companies such as power marketers or energy service providers will provide scheduling coordination services as part of a larger package of energy services, including wholesale electricity supply, load forecasting, and risk management. The charges for providing the scheduling coordinator services are bundled into the overall cost of electricity provided by the supplier. It is also possible for the City to become a CAISO certified scheduling coordinator, which requires acquisition of specialized software, completion of certification training conducted by the CAISO, and continuous staffing of a scheduling desk for 24 x 7 operations.

2. Rates

The City is responsible for setting its charges for the generation services it provides to CCA customers. The first step in setting rates is to determine the total dollars that must be collected from customers in order to cover all of the

---

16 California Public Utilities Code §366.2(c)(18)

City's costs of doing business. This amount is known as the revenue requirement and consists of operating expenses, depreciation and amortization, interest and financing expenses, taxes, and reserve funds.

The revenue requirement is allocated to the various classes of customers in the CCA program, such as residential, small commercial, medium commercial, large industrial, agricultural, and street lighting customers. Revenue allocation is typically done on a cost of service basis, so that rates are reflective of differences in the City's costs of serving the different customer classes. The City may employ load research to estimate customer class load profiles and cost of service by use of sampling techniques, whereby load research meters that can record customer electricity consumption on a 5 to 15 minute interval basis are installed on a small sample of customers within each rate class. Alternatively, the City may utilize the customer class load profiles created by PG&E.

Rate design is the process of setting the specific charges applicable to customer electricity usage. Rate schedules define the charges for each kWh, kW or other unit of electric service, and there may be one or more rate schedules applicable to each customer class. Rates are set so recover the City's revenue requirement on a forecast basis and are adjusted as needed to maintain sufficient revenues for the City.

3. Account Services

The City must be able to exchange customer meter usage data electronically with PG&E using the utility's standard electronic data interchange procedures and formats. The City must receive and process customer payments collected by PG&E. Aggregators may also need the capability to calculate individual customer bills and provide the amount to be collected to PG&E in the formats and by the timelines required for inclusion in the bills sent by the local utilities. PG&E is the only local utility that offers "rate ready" billing service, whereby PG&E will calculate individual customer bills using the rates provided by the City. PG&E also offers "bill ready" billing service whereby the City calculates the amounts due from each customer and submits to PG&E for collections. SCE and SDG&E only offer "bill ready" billing.

The City must also be able to obtain customer meter data and process the data for submission to the CAISO through its scheduling coordinator so that the CAISO can complete its financial settlement process. Customer meter data must be processed in accordance with the CPUC's protocols for verification, estimation, and editing (VEE) of meter data. PG&E will perform the VEE function for Aggregators as part of their metering service function. However, the City must apply load profiles to the usage data of customers whose consumption is measured on a cumulative monthly basis (e.g. residential and small commercial) in order to create the hourly usage data that must be submitted to the CAISO.

4. Administration

Administration and management of the CCA program includes finance, legal, regulatory, contract management and other program management functions. The scope of the administrative function depends on the complexity of the CCA implementation, which can range from a single contract with an energy services provider for operation of the program to the planning and staffing required for in-house operation and management of all aspects of the CCA program, with variations in between these two extremes. At a minimum, a senior level manager with experience in the electric utility industry should head the CCA program.

Appendix E – Base Case Pro Forma And Supporting Data

CITY OF EMERYVILLE
SUMMARY OF PRO FORMA RESULTS ($ MILLIONS)
50% RENEWABLE ENERGY

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	10.8	0.9	0.7	3.6	0.1	0.1	16.1	17.9	1.8	6%
2007	11.0	0.9	0.7	3.4	0.1	0.1	16.2	18.2	2.0	7%
2008	10.7	0.9	0.7	3.5	0.1	1.2	17.1	18.9	1.8	6%
2009	11.0	1.0	0.7	2.5	0.1	1.2	16.5	19.4	2.9	9%
2010	11.4	1.1	0.7	2.3	0.1	1.6	17.2	20.4	3.2	10%
2011	11.9	1.1	0.8	2.4	0.1	1.6	17.8	21.0	3.2	10%
2012	12.3	1.2	0.8	2.5	0.1	1.5	18.4	21.7	3.4	10%
2013	11.0	1.2	0.8	1.1	0.1	3.2	17.4	20.6	3.2	10%
2014	11.4	1.3	0.8	1.1	0.1	3.2	17.9	21.2	3.3	10%
2015	12.2	1.3	0.8	1.1	0.1	3.1	18.7	21.9	3.3	9%
2016	12.6	1.4	0.8	1.1	0.1	3.1	19.1	22.5	3.4	9%
2017	13.3	1.4	0.8	1.2	0.1	3.0	19.8	23.6	3.8	10%
2018	14.3	1.6	0.8	1.2	0.1	3.0	21.0	25.3	4.4	11%
2019	15.3	1.7	0.8	1.2	0.1	2.9	22.0	26.9	4.9	12%
2020	16.4	1.7	0.8	1.2	0.1	2.9	23.1	27.8	4.7	11%
2021	16.7	1.7	0.8	1.2	0.1	2.8	23.4	28.0	4.7	11%
2022	17.2	1.8	0.9	1.2	0.1	2.7	23.9	28.7	4.8	11%
2023	18.1	1.9	0.9	-	0.1	2.6	23.6	28.9	5.3	12%
2024	19.3	2.0	0.9	-	0.1	2.6	24.9	30.6	5.8	12%
Total	257.0	26.1	15.0	31.8	1.4	42.4	373.8	443.5	69.7	10%

CITY OF EMERYVILLE
MONTHLY CUSTOMER BILL IMPACT ($/MONTH)
50% RENEWABLE ENERGY

Year	Monthly Bill Impact Residential	Monthly Bill Impact Small Commercial	Monthly Bill Impact Medium Commercial	Monthly Bill Impact Medium Industrial	Monthly Bill Impact Large Industrial	Monthly Bill Impact Agricultural	Monthly Bill Impact Street Lighting
2005	0	0	0	0	0	0	0
2006	3	25	204	571	7,002	0	18
2007	3	28	224	626	7,670	0	20
2008	3	24	207	580	7,100	0	18
2009	5	37	318	891	10,915	0	28
2010	5	41	351	981	12,021	0	31
2011	5	41	346	969	11,868	0	31
2012	5	42	357	1,000	12,252	0	32
2013	5	39	334	936	11,464	0	30
2014	5	40	342	958	11,741	0	30
2015	5	39	333	933	11,426	0	29
2016	5	40	341	955	11,703	0	30
2017	5	44	375	1,048	12,838	0	33
2018	6	50	425	1,189	14,567	0	37
2019	7	55	466	1,304	15,974	0	41
2020	6	52	444	1,242	15,210	0	39
2021	6	51	433	1,210	14,821	0	38
2022	6	52	441	1,233	15,106	0	39
2023	7	56	477	1,328	16,233	0	42
2024	7	61	514	1,433	17,515	0	45
Total	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A

CITY OF EMERYVILLE
ELECTRIC SUPPLY RESOURCE MIX
50% RENEWABLE ENERGY

CATEGORY	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Spot Market Purchases	0%	15%	15%	10%	11%	16%	14%	11%	12%	13%	13%	12%	10%	10%	11%	12%
Contract Purchases	0%	71%	70%	69%	68%	30%	29%	29%	10%	10%	10%	10%	10%	10%	9%	9%
Power Production - Natural Gas	0%	0%	0%	0%	0%	33%	33%	32%	32%	31%	31%	30%	30%	29%	29%	28%
Renewable Energy Purchases	0%	14%	15%	0%	0%	1%	4%	9%	0%	0%	1%	4%	8%	8%	9%	10%
Power Production - Renewable Energy	0%	0%	0%	23%	22%	21%	20%	20%	47%	46%	45%	44%	43%	43%	42%	41%
Off System Sales	0%	0%	0%	-2%	-2%	0%	0%	0%	-1%	-1%	-1%	-1%	0%	0%	0%	0%
Total	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

CITY OF EMERYVILLE
ELECTRIC SUPPLY RESOURCE MIX
50% RENEWABLE ENERGY

CATEGORY	2021	2022	2023	2024
Spot Market Purchases	12%	13%	14%	14%
Contract Purchases	9%	9%	9%	9%
Power Production - Natural Gas	28%	28%	27%	27%
Renewable Energy Purchases	10%	11%	12%	12%
Power Production - Renewable Energy	40%	39%	38%	38%
Off System Sales	0%	0%	0%	0%
Total	100%	100%	100%	100%

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
50% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012
I. PG&E PG&E'S UNBUNDLED GENERATION RATES ($/KWH)								
RESIDENTIAL	$0.06782	$0.06718	$0.06732	$0.06879	$0.06943	$0.07187	$0.07305	$0.07440
SMALL COMMERCIAL (A-1 & A6)	$0.08024	$0.07947	$0.07964	$0.08140	$0.08217	$0.08509	$0.08650	$0.08811
MEDIUM COMMERCIAL (A-10)	$0.10126	$0.10028	$0.10049	$0.10274	$0.10372	$0.10745	$0.10926	$0.11132
MEDIUM INDUSTRIAL (E-19)	$0.09198	$0.09110	$0.09129	$0.09333	$0.09421	$0.09759	$0.09922	$0.10108
LARGE INDUSTRIAL (E-20)	$0.08459	$0.08378	$0.08396	$0.08582	$0.08663	$0.08972	$0.09121	$0.09292
AGRICULTURAL PUMPING	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453
STREET LIGHTING AND TRAFFIC CONTROL	$0.06307	$0.06248	$0.06261	$0.06397	$0.06456	$0.06682	$0.06791	$0.06916
II. PG&E PG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)								
RESIDENTIAL	$0	$1,379,646	$1,403,281	$1,455,473	$1,491,038	$1,566,638	$1,616,213	$1,670,770
SMALL COMMERCIAL (A-1 & A6)	$0	$1,967,979	$2,001,740	$2,076,686	$2,127,646	$2,236,344	$2,307,501	$2,385,839
MEDIUM COMMERCIAL (A-10)	$0	$5,117,507	$5,205,436	$5,401,792	$5,534,977	$5,820,173	$6,006,506	$6,211,733
MEDIUM INDUSTRIAL (E-19)	$0	$3,885,606	$3,952,328	$4,100,988	$4,201,916	$4,417,718	$4,558,816	$4,714,197
LARGE INDUSTRIAL (E-20)	$0	$5,465,640	$5,559,440	$5,767,976	$5,909,682	$6,212,242	$6,410,207	$6,628,176
AGRICULTURAL PUMPING	$0	$0	$0	$0	$0	$0	$0	$0
STREET LIGHTING AND TRAFFIC CONTROL	$0	$92,199	$92,391	$94,401	$95,274	$98,607	$100,216	$102,059
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$0	$17,908,576	$18,214,616	$18,897,315	$19,360,532	$20,351,721	$20,999,458	$21,712,774
AVERAGE RATE ($/KWH)	$0.0000	$0.0871	$0.0873	$0.0892	$0.0900	$0.0933	$0.0948	$0.0966
III. OPERATING EXPENSES ($)								
1. POWER SUPPLY COSTS:								
(A) ANCILLARY SERVICES AND RESERVES	$0	$663,337	$688,547	$717,058	$778,624	$830,610	$891,663	$930,514
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$0	$2,120,630	$2,409,416	$8,394	$61,849	$167,200	$755,570	$1,585,927
(C) DWR POWER	$0	$0	$0	$0	$0	$0	$0	$0
(D) POWER PRODUCTION	$0	$0	$0	$1,174,941	$1,189,753	$4,494,901	$4,596,697	$4,712,231
(E) CONTRACT PURCHASES	$0	$7,714,065	$7,714,065	$8,392,797	$8,392,797	$4,512,142	$4,512,142	$4,512,142
(F) MARKET PURCHASES	$0	$1,681,786	$1,692,886	$1,315,199	$1,584,556	$2,297,764	$2,189,103	$1,826,535
SUBTOTAL POWER SUPPLY COSTS	$0	$12,179,818	$12,504,914	$11,608,389	$12,007,579	$12,302,617	$12,945,174	$13,567,348
2. OTHER COSTS:								
(A) CALIFORNIA ISO COSTS	$0	$200,851	$208,830	$217,295	$228,403	$239,088	$250,707	$261,016
(B) NON-BYPASSABLE CHARGES	$0	$3,619,814	$3,436,150	$3,508,000	$2,513,470	$2,312,623	$2,378,538	$2,451,876
(C) START UP COSTS AMORTIZATION	$0	$5,528	$5,833	$6,153	$6,492	$6,849	$7,225	$7,623
(D) OPERATIONS & SCHEDULING COORDINATION	$0	$714,241	$721,899	$729,673	$737,562	$745,570	$753,699	$761,949
SUBTOTAL - OTHER COSTS	$0	$4,540,435	$4,372,712	$4,461,121	$3,485,927	$3,304,131	$3,390,170	$3,482,464

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
50% RENEWABLE ENERGY

CATEGORY		[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012
3. UTILITY OPERATIONS:									
(A) DISTRIBUTION O&M		$0	$0	$0	$0	$0	$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0	$0	$0	$0	$0	$0
(C) METERING & BILLING		$0	$51,769	$53,853	$56,021	$58,277	$60,623	$63,064	$65,603
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$0	$51,769	$53,853	$56,021	$58,277	$60,623	$63,064	$65,603
TOTAL OPERATING EXPENSES		$0	$16,772,022	$16,931,480	$16,125,532	$15,551,783	$15,667,371	$16,398,408	$17,115,415
IV. INTEREST EXPENSE ($)									
(A) INTEREST EXPENSE ($)		$0	$22,025	$21,721	$1,094,811	$1,079,653	$1,504,166	$1,481,214	$1,457,000
(B) DEBT COVERAGE		$0	$0	$0	$0	$0	$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$0	$59,663	$61,716	$65,037	$70,991	$75,431	$77,792	$80,579
SUBTOTAL - FINANCING EXPENSE		$0	$81,689	$83,438	$1,159,847	$1,150,645	$1,579,597	$1,559,006	$1,537,579
V. REVENUES FROM MARKET SALES ($)									
(A) EXCESS ENERGY SALES		$0	$30,445	$33,470	$219,480	$190,886	$64,429	$49,099	$78,170
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$0	$695,464	$746,663	$1,649	$11,527	$29,902	$115,085	$222,461
SUBTOTAL - OTHER REVENUES		$0	$725,908	$780,133	$221,129	$202,413	$94,330	$164,184	$300,631
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$0	$16,127,802	$16,234,785	$17,064,250	$16,500,014	$17,152,637	$17,793,229	$18,352,364
VII. CCA OPERATIONAL MARGIN		**$0**	**$1,780,774**	**$1,979,832**	**$1,833,065**	**$2,860,518**	**$3,199,084**	**$3,206,229**	**$3,360,411**
NET PRESENT VALUE OF OPERATIONAL MARGIN	$26,198,566.30								
NOMINAL MARGIN	$69,656,803.18								

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
50% RENEWABLE ENERGY

CATEGORY	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021
I. PG&E PG&E'S UNBUNDLED GENERATION RATES ($/KWH)									
RESIDENTIAL	$0.06960	$0.07055	$0.07194	$0.07259	$0.07509	$0.07932	$0.08296	$0.08444	$0.08393
SMALL COMMERCIAL (A-1 & A6)	$0.08237	$0.08351	$0.08517	$0.08595	$0.08894	$0.09401	$0.09836	$0.10013	$0.09951
MEDIUM COMMERCIAL (A-10)	$0.10398	$0.10543	$0.10756	$0.10855	$0.11237	$0.11885	$0.12441	$0.12666	$0.12588
MEDIUM INDUSTRIAL (E-19)	$0.09445	$0.09576	$0.09768	$0.09858	$0.10203	$0.10789	$0.11291	$0.11495	$0.11424
LARGE INDUSTRIAL (E-20)	$0.08685	$0.08805	$0.08981	$0.09063	$0.09379	$0.09915	$0.10375	$0.10562	$0.10497
AGRICULTURAL PUMPING	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453
STREET LIGHTING AND TRAFFIC CONTROL	$0.06472	$0.06560	$0.06688	$0.06749	$0.06980	$0.07371	$0.07708	$0.07845	$0.07797
II. PG&E PG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)									
RESIDENTIAL	$1,586,394	$1,632,131	$1,689,287	$1,730,176	$1,816,587	$1,947,821	$2,067,737	$2,136,086	$2,154,934
SMALL COMMERCIAL (A-1 & A6)	$2,263,774	$2,329,378	$2,411,447	$2,470,047	$2,594,304	$2,783,206	$2,955,778	$3,053,963	$3,080,744
MEDIUM COMMERCIAL (A-10)	$5,889,285	$6,060,952	$6,275,954	$6,429,148	$6,755,197	$7,251,443	$7,704,674	$7,962,027	$8,031,353
MEDIUM INDUSTRIAL (E-19)	$4,470,840	$4,600,870	$4,763,651	$4,879,731	$5,126,435	$5,501,754	$5,844,573	$6,039,382	$6,092,111
LARGE INDUSTRIAL (E-20)	$6,287,835	$6,470,320	$6,698,669	$6,861,634	$7,207,507	$7,733,473	$8,213,941	$8,487,168	$8,561,461
AGRICULTURAL PUMPING	$0	$0	$0	$0	$0	$0	$0	$0	$0
STREET LIGHTING AND TRAFFIC CONTROL	$95,505	$96,799	$98,699	$99,589	$103,000	$108,781	$113,748	$115,763	$115,062
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$20,593,633	$21,190,452	$21,937,706	$22,470,325	$23,603,030	$25,326,477	$26,900,451	$27,794,389	$28,035,665
AVERAGE RATE ($/KWH)	$0.0903	$0.0915	$0.0934	$0.0942	$0.0975	$0.1031	$0.1079	$0.1098	$0.1092
III. OPERATING EXPENSES ($)									
1. POWER SUPPLY COSTS:									
(A) ANCILLARY SERVICES AND RESERVES	$964,365	$997,266	$1,038,303	$1,067,760	$1,131,319	$1,226,972	$1,312,833	$1,360,509	$1,372,840
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$0	$86,633	$315,463	$828,031	$1,649,656	$1,995,166	$2,346,982	$2,614,090	$2,779,518
(C) DWR POWER	$0	$0	$0	$0	$0	$0	$0	$0	$0
(D) POWER PRODUCTION	$7,099,812	$7,228,231	$7,394,254	$7,505,096	$7,771,860	$8,178,878	$8,534,560	$8,717,311	$8,747,110
(E) CONTRACT PURCHASES	$1,934,034	$1,934,034	$2,186,248	$2,186,248	$2,186,248	$2,186,248	$2,186,248	$2,556,907	$2,556,907
(F) MARKET PURCHASES	$2,177,249	$2,369,267	$2,463,706	$2,256,237	$1,923,335	$2,251,226	$2,565,845	$2,783,527	$2,903,228
SUBTOTAL POWER SUPPLY COSTS	$12,175,460	$12,615,431	$13,397,974	$13,843,372	$14,662,418	$15,838,490	$16,946,468	$18,032,344	$18,359,603
2. OTHER COSTS:									
(A) CALIFORNIA ISO COSTS	$271,267	$281,764	$293,175	$304,092	$317,823	$334,237	$350,328	$364,065	$375,668
(B) NON-BYPASSABLE CHARGES	$1,093,401	$1,109,097	$1,125,025	$1,141,189	$1,157,592	$1,174,239	$1,191,133	$1,208,277	$1,225,675
(C) START UP COSTS AMORTIZATION	$8,042	$8,484	$8,951	$9,443	$9,963	$10,511	$11,089	$11,699	$12,342
(D) OPERATIONS & SCHEDULING COORDINATION	$770,323	$778,822	$787,449	$796,206	$805,093	$814,114	$823,271	$832,565	$841,998
SUBTOTAL - OTHER COSTS	$2,143,033	$2,178,167	$2,214,600	$2,250,930	$2,290,471	$2,333,101	$2,375,820	$2,416,605	$2,455,683

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
50% RENEWABLE ENERGY

CATEGORY		[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021
3. UTILITY OPERATIONS:										
(A) DISTRIBUTION O&M		$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0	$0	$0	$0	$0	$0	$0
(C) METERING & BILLING		$68,244	$70,992	$73,851	$76,825	$79,919	$83,138	$86,486	$89,969	$93,593
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$68,244	$70,992	$73,851	$76,825	$79,919	$83,138	$86,486	$89,969	$93,593
TOTAL OPERATING EXPENSES		$14,386,738	$14,864,591	$15,686,426	$16,171,127	$17,032,809	$18,254,729	$19,408,774	$20,538,918	$20,908,880
IV. INTEREST EXPENSE ($)										
(A) INTEREST EXPENSE ($)		$3,154,137	$3,103,404	$3,049,880	$2,993,413	$2,933,840	$2,870,990	$2,804,684	$2,734,731	$2,660,931
(B) DEBT COVERAGE		$0	$0	$0	$0	$0	$0	$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$82,162	$84,380	$87,267	$89,289	$93,844	$100,886	$107,283	$110,844	$111,717
SUBTOTAL - FINANCING EXPENSE		$3,236,299	$3,187,783	$3,137,147	$3,082,702	$3,027,684	$2,971,876	$2,911,968	$2,845,576	$2,772,647
V. REVENUES FROM MARKET SALES ($)										
(A) EXCESS ENERGY SALES		$218,640	$169,748	$131,297	$100,296	$77,202	$60,326	$38,698	$16,559	$2,083
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$0	$8,193	$30,863	$89,741	$174,398	$211,924	$250,240	$279,590	$298,064
SUBTOTAL - OTHER REVENUES		$218,640	$177,941	$162,160	$190,037	$251,600	$272,250	$288,938	$296,150	$300,147
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$17,404,396	$17,874,433	$18,661,413	$19,063,792	$19,808,893	$20,954,355	$22,031,804	$23,088,344	$23,381,380
VII. CCA OPERATIONAL MARGIN		**$3,189,237**	**$3,316,019**	**$3,276,293**	**$3,406,533**	**$3,794,137**	**$4,372,123**	**$4,868,647**	**$4,706,045**	**$4,654,285**
NET PRESENT VALUE OF OPERATIONAL MARGIN	$26,198,566.30									
NOMINAL MARGIN	$69,656,803.18									

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
50% RENEWABLE ENERGY

CATEGORY	[18] 2022	[19] 2023	[20] 2024
I. PG&E PG&E'S UNBUNDLED GENERATION RATES ($/KWH)			
RESIDENTIAL	$0.08456	$0.08285	$0.08655
SMALL COMMERCIAL (A-1 & A6)	$0.10027	$0.09911	$0.10354
MEDIUM COMMERCIAL (A-10)	$0.12684	$0.12662	$0.13228
MEDIUM INDUSTRIAL (E-19)	$0.11512	$0.11448	$0.11960
LARGE INDUSTRIAL (E-20)	$0.10577	$0.10481	$0.10949
AGRICULTURAL PUMPING	$0.00453	$0.00000	$0.00000
STREET LIGHTING AND TRAFFIC CONTROL	$0.07856	$0.07663	$0.08006
II. PG&E PG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)			
RESIDENTIAL	$2,203,741	$2,191,560	$2,323,848
SMALL COMMERCIAL (A-1 & A6)	$3,150,729	$3,161,101	$3,351,913
MEDIUM COMMERCIAL (A-10)	$8,214,422	$8,323,171	$8,825,580
MEDIUM INDUSTRIAL (E-19)	$6,230,795	$6,289,465	$6,669,114
LARGE INDUSTRIAL (E-20)	$8,756,117	$8,806,574	$9,338,163
AGRICULTURAL PUMPING	$0	$0	$0
STREET LIGHTING AND TRAFFIC CONTROL	$115,925	$113,089	$118,143
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$28,671,730	$28,884,960	$30,626,762
AVERAGE RATE ($/KWH)	$0.1100	$0.1092	$0.1141
III. OPERATING EXPENSES ($)			
1. POWER SUPPLY COSTS:			
(A) ANCILLARY SERVICES AND RESERVES	$1,407,544	$1,478,197	$1,572,295
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$3,007,172	$3,357,807	$3,811,311
(C) DWR POWER	$0	$0	$0
(D) POWER PRODUCTION	$8,875,581	$9,155,459	$9,528,976
(E) CONTRACT PURCHASES	$2,556,907	$2,556,907	$2,556,907
(F) MARKET PURCHASES	$3,102,808	$3,427,091	$3,840,585
SUBTOTAL POWER SUPPLY COSTS	$18,950,012	$19,975,461	$21,310,073
2. OTHER COSTS:			
(A) CALIFORNIA ISO COSTS	$389,317	$406,007	$424,856
(B) NON-BYPASSABLE CHARGES	$1,180,649	$0	$0
(C) START UP COSTS AMORTIZATION	$13,021	$13,737	$14,493
(D) OPERATIONS & SCHEDULING COORDINATION	$851,572	$861,291	$871,155
SUBTOTAL - OTHER COSTS	$2,434,559	$1,281,035	$1,310,503

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
50% RENEWABLE ENERGY

CATEGORY		[18] 2022	[19] 2023	[20] 2024
3. UTILITY OPERATIONS:				
(A) DISTRIBUTION O&M		$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0
(C) METERING & BILLING		$97,363	$101,285	$105,365
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$97,363	$101,285	$105,365
TOTAL OPERATING EXPENSES		$21,481,934	$21,357,781	$22,725,941
IV. INTEREST EXPENSE ($)				
(A) INTEREST EXPENSE ($)		$2,583,071	$2,500,929	$2,414,269
(B) DEBT COVERAGE		$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$114,546	$120,354	$127,612
SUBTOTAL - FINANCING EXPENSE		$2,697,617	$2,621,283	$2,541,881
V. REVENUES FROM MARKET SALES ($)				
(A) EXCESS ENERGY SALES		$0	$0	$0
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$323,199	$361,698	$411,663
SUBTOTAL - OTHER REVENUES		$323,199	$361,698	$411,663
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$23,856,353	$23,617,366	$24,856,160
VII. CCA OPERATIONAL MARGIN		**$4,815,377**	**$5,267,594**	**$5,770,602**
NET PRESENT VALUE OF OPERATIONAL MARGIN	$26,198,566.30			
NOMINAL MARGIN	$69,656,803.18			

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
DEBT SERVICE
50% RENEWABLE ENERGY

I. TOTAL DEBT ISSUANCES

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
(A) STARTUP COSTS	$0	$400,458	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$0	$0	$0	$19,516,549	$0	$8,009,153	$0	$0	$31,321,510	$0	$0
SUBTOTAL - DEBT ISSUANCE	$0	$400,458	$0	$19,516,549	$0	$8,009,153	$0	$0	$31,321,510	$0	$0

II. TOTAL DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
(A) STARTUP COSTS	$0	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554
(B) GENERATION DEVELOPMENT	$0	$0	$0	$1,342,844	$1,342,844	$1,893,917	$1,893,917	$1,893,917	$4,049,005	$4,049,005	$4,049,005
SUBTOTAL - FINANCING COSTS	$0	$27,554	$27,554	$1,370,397	$1,370,397	$1,921,470	$1,921,470	$1,921,470	$4,076,559	$4,076,559	$4,076,559
(D) DEBT COVERAGE (1.25)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL DEBT SERVICE	$0	$27,554	$27,554	$1,370,397	$1,370,397	$1,921,470	$1,921,470	$1,921,470	$4,076,559	$4,076,559	$4,076,559

III. INTEREST PORTION OF DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
(A) STARTUP COSTS	$0	$22,025	$21,721	$21,400	$21,062	$20,705	$20,328	$19,931	$19,511	$19,069	$18,603
(B) GENERATION DEVELOPMENT	$0	$0	$0	$1,073,410	$1,058,591	$1,483,461	$1,460,886	$1,437,069	$3,134,626	$3,084,335	$3,031,278
SUBTOTAL - FINANCING COSTS	$0	$22,025	$21,721	$1,094,811	$1,079,653	$1,504,166	$1,481,214	$1,457,000	$3,154,137	$3,103,404	$3,049,880
TOTAL INTEREST	$0	$22,025	$21,721	$1,094,811	$1,079,653	$1,504,166	$1,481,214	$1,457,000	$3,154,137	$3,103,404	$3,049,880

IV. PRINCIPAL PORTION OF DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
(A) STARTUP COSTS	$0	$5,528	$5,833	$6,153	$6,492	$6,849	$7,225	$7,623	$8,042	$8,484	$8,951
(B) GENERATION DEVELOPMENT	$0	$0	$0	$269,434	$284,252	$410,456	$433,031	$456,848	$914,380	$964,671	$1,017,728
SUBTOTAL - FINANCING COSTS	$0	$5,528	$5,833	$275,587	$290,744	$417,305	$440,256	$464,470	$922,422	$973,155	$1,026,679
TOTAL PRINCIPAL	$0	$5,528	$5,833	$275,587	$290,744	$417,305	$440,256	$464,470	$922,422	$973,155	$1,026,679

V. RESERVES

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
DEBT COVERAGE RESERVE ADDITIONS ($ B.O.Y.)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEBT COVERAGE RESERVE ADDITIONS ($ E.O.Y.)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEBT SERVICE RESERVE ($)	$0	$40,046	$40,046	$1,991,701	$1,991,701	$2,792,616	$2,792,616	$2,792,616	$5,924,767	$5,924,767	$5,924,767
TOTAL DEBT SERVICE RESERVES	$0	$40,046	$40,046	$1,991,701	$1,991,701	$2,792,616	$2,792,616	$2,792,616	$5,924,767	$5,924,767	$5,924,767

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
DEBT SERVICE
50% RENEWABLE ENERGY

I. TOTAL DEBT ISSUANCES

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - DEBT ISSUANCE	$0	$0	$0	$0	$0	$0	$0	$0	$0

II. TOTAL DEBT SERVICE

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554
(B) GENERATION DEVELOPMENT	$4,049,005	$4,049,005	$4,049,005	$4,049,005	$4,049,005	$4,049,005	$4,049,005	$4,049,005	$4,049,005
SUBTOTAL - FINANCING COSTS	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559
(D) DEBT COVERAGE (1.25)	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL DEBT SERVICE	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559	$4,076,559

III. INTEREST PORTION OF DEBT SERVICE

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$18,110	$17,591	$17,043	$16,465	$15,855	$15,211	$14,533	$13,816	$13,061
(B) GENERATION DEVELOPMENT	$2,975,303	$2,916,249	$2,853,948	$2,788,219	$2,718,876	$2,645,719	$2,568,538	$2,487,113	$2,401,208
SUBTOTAL - FINANCING COSTS	$2,993,413	$2,933,840	$2,870,990	$2,804,684	$2,734,731	$2,660,931	$2,583,071	$2,500,929	$2,414,269
TOTAL INTEREST	$2,993,413	$2,933,840	$2,870,990	$2,804,684	$2,734,731	$2,660,931	$2,583,071	$2,500,929	$2,414,269

IV. PRINCIPAL PORTION OF DEBT SERVICE

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$9,443	$9,963	$10,511	$11,089	$11,699	$12,342	$13,021	$13,737	$14,493
(B) GENERATION DEVELOPMENT	$1,073,703	$1,132,756	$1,195,058	$1,260,786	$1,330,129	$1,403,286	$1,480,467	$1,561,893	$1,647,797
SUBTOTAL - FINANCING COSTS	$1,083,146	$1,142,719	$1,205,569	$1,271,875	$1,341,828	$1,415,629	$1,493,488	$1,575,630	$1,662,290
TOTAL PRINCIPAL	$1,083,146	$1,142,719	$1,205,569	$1,271,875	$1,341,828	$1,415,629	$1,493,488	$1,575,630	$1,662,290

V. RESERVES

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
DEBT COVERAGE RESERVE ADDITIONS ($ B.O.Y.)	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEBT COVERAGE RESERVE ADDITIONS ($ E.O.Y.)	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEBT SERVICE RESERVE ($)	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767
TOTAL DEBT SERVICE RESERVES	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767	$5,924,767

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES
50% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION I - PROJECTED MARKET PRICES:														
(A) MARKET ENERGY ($/MWH):														
AVERAGE ENERGY PRICE	$48.30	$45.27	$46.24	$47.48	$52.08	$55.51	$59.70	$61.48	$62.66	$63.65	$65.33	$65.80	$69.35	$75.66
ON-PEAK ENERGY PRICE	$55.54	$52.06	$53.18	$54.60	$59.90	$63.83	$68.65	$70.70	$72.06	$73.20	$75.13	$75.67	$79.75	$87.01
OFF-PEAK ENERGY PRICE	$41.05	$38.48	$39.30	$40.36	$44.27	$47.18	$50.74	$52.26	$53.26	$54.11	$55.53	$55.93	$58.95	$64.31
REAL-TIME PREMIUM	$4.83	$4.53	$4.62	$4.75	$5.21	$5.55	$5.97	$6.15	$6.27	$6.37	$6.53	$6.58	$6.93	$7.57
(B) CDWR CONTRACT ENERGY ($/MWH):														
AVERAGE CDWR CONTRACT PRICE	$74.87	$71.61	$71.95	$70.26	$67.04	$97.01	$76.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(C) RENEWABLE PORTFOLIO STANDARD (RPS):														
RPS REQUIREMENTS (%)	13.0%	14.0%	15.5%	17.0%	18.5%	20.0%	24.3%	28.6%	32.9%	37.1%	41.4%	45.7%	50.0%	50.0%
RPS ENERGY PRICE ($/MWH)	$67.21	$67.88	$68.56	$69.25	$69.94	$70.64	$71.35	$72.06	$72.78	$73.51	$74.24	$74.99	$78.28	$85.40
RPS CONTRACT CAPACITY (MW)	-	4	4	0	0	0	1	2	-	0	0	1	2	2
TOTAL RENEWABLE CAPACITY (MW)	-	4	4	6	6	6	7	8	13	13	13	14	15	15
(D) ANCILLARY SERVICE PRICES ($/MWH):														
SPINNING RESERVE	$10.92	$10.23	$10.45	$10.73	$11.77	$12.54	$13.49	$13.90	$14.16	$14.39	$14.76	$14.87	$15.67	$17.10
NON-SPINNING RESERVE	$6.81	$6.38	$6.52	$6.69	$7.34	$7.83	$8.42	$8.67	$8.84	$8.98	$9.21	$9.28	$9.78	$10.67
REPLACEMENT RESERVE	$10.00	$9.37	$9.57	$9.83	$10.78	$11.49	$12.36	$12.73	$12.97	$13.18	$13.52	$13.62	$14.36	$15.66
REGULATION - UP	$31.93	$29.92	$30.57	$31.38	$34.43	$36.69	$39.46	$40.64	$41.42	$42.07	$43.18	$43.49	$45.84	$50.01
REGULATION - DOWN	$31.93	$29.92	$30.57	$31.38	$34.43	$36.69	$39.46	$40.64	$41.42	$42.07	$43.18	$43.49	$45.84	$50.01
(E) NATURAL GAS PRICE ($/MMBtu):														
AVERAGE NATURAL GAS PRICE	$6.04	$5.49	$5.32	$5.28	$5.21	$5.29	$5.43	$5.59	$5.70	$5.79	$5.94	$5.98	$6.30	$6.88
REFEENCE GAS PRICE - HIGH	$7.55	$6.86	$6.64	$6.59	$6.51	$6.61	$6.78	$6.99	$7.12	$7.23	$7.42	$7.48	$7.88	$8.60
REFEENCE GAS PRICE - MID	$6.04	$5.49	$5.32	$5.28	$5.21	$5.29	$5.43	$5.59	$5.70	$5.79	$5.94	$5.98	$6.30	$6.88
REFEENCE GAS PRICE - LOW	$4.53	$4.12	$3.99	$3.96	$3.91	$3.96	$4.07	$4.19	$4.27	$4.34	$4.45	$4.49	$4.73	$5.16
(F) EMISSIONS CREDIT PRICE ($/LB):	$10.00	$10.25	$10.51	$10.77	$11.04	$11.31	$11.60	$11.89	$12.18	$12.49	$12.80	$13.12	$13.45	$13.79
(G) CAPACITY ($/MW):	$100,000	$102,500	$105,063	$107,689	$110,381	$113,141	$115,969	$118,869	$121,840	$124,886	$128,008	$131,209	$134,489	$137,851

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU
50% RENEWABLE ENERGY

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION I - PROJECTED MARKET PRICES:						
(A) MARKET ENERGY ($/MWH):						
AVERAGE ENERGY PRICE	$80.84	$82.40	$80.74	$80.98	$84.19	$89.19
ON-PEAK ENERGY PRICE	$92.96	$94.75	$92.85	$93.13	$96.82	$102.56
OFF-PEAK ENERGY PRICE	$68.71	$70.04	$68.63	$68.83	$71.56	$75.81
REAL-TIME PREMIUM	$8.08	$8.24	$8.07	$8.10	$8.42	$8.92
(B) CDWR CONTRACT ENERGY ($/MWH):						
AVERAGE CDWR CONTRACT PRICE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(C) RENEWABLE PORTFOLIO STANDARD (RP						
RPS REQUIREMENTS (%)	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
RPS ENERGY PRICE ($/MWH)	$91.24	$93.00	$91.13	$91.41	$95.03	$100.67
RPS CONTRACT CAPACITY (MW)	3	3	3	4	4	4
TOTAL RENEWABLE CAPACITY (MW)	15	16	16	16	16	16
(D) ANCILLARY SERVICE PRICES ($/MWH):						
SPINNING RESERVE	$18.27	$18.62	$18.25	$18.30	$19.03	$20.16
NON-SPINNING RESERVE	$11.40	$11.62	$11.38	$11.42	$11.87	$12.58
REPLACEMENT RESERVE	$16.73	$17.06	$16.71	$16.76	$17.43	$18.46
REGULATION - UP	$53.43	$54.46	$53.37	$53.53	$55.65	$58.95
REGULATION - DOWN	$53.43	$54.46	$53.37	$53.53	$55.65	$58.95
(E) NATURAL GAS PRICE ($/MMBtu):						
AVERAGE NATURAL GAS PRICE	$7.35	$7.49	$7.34	$7.36	$7.65	$8.11
REFEENCE GAS PRICE - HIGH	$9.19	$9.36	$9.17	$9.20	$9.57	$10.13
REFEENCE GAS PRICE - MID	$7.35	$7.49	$7.34	$7.36	$7.65	$8.11
REFEENCE GAS PRICE - LOW	$5.51	$5.62	$5.50	$5.52	$5.74	$6.08
(F) EMISSIONS CREDIT PRICE ($/LB):	$14.13	$14.48	$14.85	$15.22	$15.60	$15.99
(G) CAPACITY ($/MW):	$141,297	$144,830	$148,451	$152,162	$155,966	$159,865

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES
50% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION II - PROJECTED LOADS AND ANCILLARY SERVICES:														
(A) PROJECTED LOADS (KWH):														
PROJECTED LOADS INCLUDING LOSSES														
ON-PEAK	0	139,968,785	142,053,255	144,168,991	146,316,463	148,496,148	150,708,528	152,954,093	155,233,342	157,546,780	159,894,919	162,278,280	164,697,392	167,152,791
OFF-PEAK	0	80,495,528	81,694,298	82,911,050	84,146,054	85,399,582	86,671,914	87,963,330	89,274,118	90,604,567	91,954,973	93,325,635	94,716,858	96,128,948
TOTAL	0	220,464,313	223,747,553	227,080,041	230,462,517	233,895,730	237,380,441	240,917,423	244,507,460	248,151,347	251,849,892	255,603,916	259,414,250	263,281,739
PROJECTED LOADS EXCLUDING LOSSES														
ON-PEAK	0	130,811,949	132,760,051	134,737,375	136,744,358	138,781,447	140,849,091	142,947,751	145,077,890	147,239,981	149,434,504	151,661,944	153,922,796	156,217,561
OFF-PEAK	0	75,229,465	76,349,812	77,486,963	78,641,172	79,812,694	81,001,788	82,208,720	83,433,755	84,677,165	85,939,227	87,220,220	88,520,428	89,840,138
TOTAL	0	206,041,414	209,109,863	212,224,338	215,385,530	218,594,140	221,850,880	225,156,470	228,511,645	231,917,147	235,373,731	238,882,164	242,443,224	246,057,700
(B) ANCILLARY SERVICES:														
ANCILLARY SERVICE REQUIREMENTS (KWH):														
SPINNING RESERVE	0	7,252,658	7,360,667	7,470,297	7,581,571	7,694,514	7,809,151	7,925,508	8,043,610	8,163,484	8,285,155	8,408,652	8,534,001	8,661,231
NON-SPINNING RESERVE	0	5,151,035	5,227,747	5,305,608	5,384,638	5,464,854	5,546,272	5,628,912	5,712,791	5,797,929	5,884,343	5,972,054	6,061,081	6,151,442
REPLACEMENT RESERVE	0	2,513,705	2,551,140	2,589,137	2,627,703	2,666,849	2,706,581	2,746,909	2,787,842	2,829,389	2,871,560	2,914,362	2,957,807	3,001,904
REGULATION - UP	0	4,635,932	4,704,972	4,775,048	4,846,174	4,918,368	4,991,645	5,066,021	5,141,512	5,218,136	5,295,909	5,374,849	5,454,973	5,536,298
REGULATION - DOWN	0	4,635,932	4,704,972	4,775,048	4,846,174	4,918,368	4,991,645	5,066,021	5,141,512	5,218,136	5,295,909	5,374,849	5,454,973	5,536,298
TOTAL - ANCILLARY SERVICES REQ.	0	24,189,262	24,549,498	24,915,137	25,286,261	25,662,952	26,045,293	26,433,370	26,827,267	27,227,073	27,632,876	28,044,766	28,462,834	28,887,174
ANCILLARY SERVICE COSTS ($)														
SPINNING RESERVE	$0	$75,372	$78,134	$81,423	$90,646	$98,048	$107,015	$111,860	$115,706	$119,286	$124,249	$127,005	$135,858	$150,437
NON-SPINNING RESERVE	$0	$33,398	$34,622	$36,079	$40,166	$43,446	$47,419	$49,566	$51,270	$52,856	$55,056	$56,277	$60,199	$66,659
REPLACEMENT RESERVE	$0	$23,927	$24,804	$25,848	$28,776	$31,126	$33,972	$35,510	$36,731	$37,868	$39,443	$40,318	$43,128	$47,757
REGULATION - UP	$0	$140,910	$146,074	$152,223	$169,466	$183,303	$200,069	$209,126	$216,316	$223,009	$232,287	$237,440	$253,990	$281,246
REGULATION - DOWN	$0	$140,910	$146,074	$152,223	$169,466	$183,303	$200,069	$209,126	$216,316	$223,009	$232,287	$237,440	$253,990	$281,246
TOTAL - ANCILLARY SERVICES COSTS	$0	$414,516	$429,707	$447,796	$498,520	$539,225	$588,544	$615,187	$636,339	$656,029	$683,322	$698,481	$747,166	$827,345
(C) PLANNING RESERVES:														
PLANNING RESERVES REQUIREMENTS (I	-	2,428	2,464	2,500	2,538	2,575	2,614	2,653	2,692	2,732	2,773	2,814	2,856	2,899
PLANNING RESERVES COSTS ($)	$0	$248,821	$258,840	$269,262	$280,105	$291,385	$303,119	$315,326	$328,026	$341,237	$354,981	$369,279	$384,154	$399,628

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU
50% RENEWABLE ENERGY

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION II - PROJECTED LOADS AND ANCILLA						
(A) PROJECTED LOADS (KWH):						
PROJECTED LOADS INCLUDING LOSSES						
ON-PEAK	169,645,020	172,174,633	174,742,190	177,348,260	179,993,422	182,678,261
OFF-PEAK	97,562,220	99,016,991	100,493,583	101,992,325	103,513,547	105,057,588
TOTAL	267,207,240	271,191,624	275,235,773	279,340,585	283,506,969	287,735,849
PROJECTED LOADS EXCLUDING LOSSES						
ON-PEAK	158,546,748	160,910,872	163,310,458	165,746,038	168,218,151	170,727,346
OFF-PEAK	91,179,645	92,539,244	93,919,237	95,319,930	96,741,633	98,184,662
TOTAL	249,726,392	253,450,116	257,229,695	261,065,967	264,959,784	268,912,008
(B) ANCILLARY SERVICES:						
ANCILLARY SERVICE REQUIREMENTS (K						
SPINNING RESERVE	8,790,369	8,921,444	9,054,485	9,189,522	9,326,584	9,465,703
NON-SPINNING RESERVE	6,243,160	6,336,253	6,430,742	6,526,649	6,623,995	6,722,800
REPLACEMENT RESERVE	3,046,662	3,092,091	3,138,202	3,185,005	3,232,509	3,280,726
REGULATION - UP	5,618,844	5,702,628	5,787,668	5,873,984	5,961,595	6,050,520
REGULATION - DOWN	5,618,844	5,702,628	5,787,668	5,873,984	5,961,595	6,050,520
TOTAL - ANCILLARY SERVICES REQ.	29,317,878	29,755,044	30,198,766	30,649,145	31,106,279	31,570,270
ANCILLARY SERVICE COSTS ($)						
SPINNING RESERVE	$163,122	$168,745	$167,820	$170,834	$180,253	$193,796
NON-SPINNING RESERVE	$72,280	$74,772	$74,362	$75,698	$79,871	$85,872
REPLACEMENT RESERVE	$51,783	$53,569	$53,275	$54,232	$57,222	$61,521
REGULATION - UP	$304,961	$315,475	$313,744	$319,380	$336,988	$362,307
REGULATION - DOWN	$304,961	$315,475	$313,744	$319,380	$336,988	$362,307
TOTAL - ANCILLARY SERVICES COSTS	$897,107	$928,036	$922,944	$939,524	$991,321	$1,065,803
(C) PLANNING RESERVES:						
PLANNING RESERVES REQUIREMENTS (I	2,942	2,986	3,031	3,076	3,122	3,168
PLANNING RESERVES COSTS ($)	$415,726	$432,473	$449,895	$468,020	$486,876	$506,492

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES
50% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION III - PROJECTED RESOURCES:														
(A) RENEWABLE PORTFOLIO STANDARD (KWH):														
ON-PEAK	0	19,525,646	21,964,985	75,757	645,460	1,976,139	8,425,453	16,016,756	0	831,342	3,461,646	9,294,199	17,074,458	18,686,316
OFF-PEAK	0	11,229,126	12,631,981	0	0	0	1,452,901	5,015,073	0	0	0	471,056	2,458,072	3,068,468
TOTAL	0	30,754,772	34,596,965	75,757	645,460	1,976,139	9,878,355	21,031,829	0	831,342	3,461,646	9,765,256	19,532,530	21,754,784
COSTS ($):														
ON-PEAK	0	1,348,545	1,532,189	8,394	61,849	167,200	641,189	1,203,631	0	86,633	315,463	785,827	1,435,036	1,705,260
OFF-PEAK	0	772,085	877,227	0	0	0	114,381	382,296	0	0	0	42,204	214,620	289,906
TOTAL	0	2,120,630	2,409,416	8,394	61,849	167,200	755,570	1,585,927	0	86,633	315,463	828,031	1,649,656	1,995,166
(B) CDWR CONTRACT ENERGY (KWH):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COSTS ($):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BALANCE (KWH):														
ON-PEAK	0	120,443,140	120,088,270	144,093,234	145,671,003	146,520,009	142,283,074	136,937,337	155,233,342	156,715,438	156,433,273	152,984,081	147,622,934	148,466,475
OFF-PEAK	0	69,266,402	69,062,317	82,911,050	84,146,054	85,399,582	85,219,012	82,948,257	89,274,118	90,604,567	91,954,973	92,854,579	92,258,785	93,060,480
TOTAL	0	189,709,541	189,150,588	227,004,285	229,817,057	231,919,591	227,502,087	219,885,594	244,507,460	247,320,005	248,388,246	245,838,660	239,881,720	241,526,955
(C) POWER PRODUCTION (KWH):														
ON-PEAK	0	0	0	29,773,654	29,218,940	73,421,454	72,910,229	72,419,453	111,712,788	111,260,489	110,826,282	110,409,443	110,009,278	109,625,120
OFF-PEAK	0	0	0	21,649,298	21,245,948	53,386,893	53,015,167	52,658,309	81,229,646	80,900,766	80,585,041	80,281,945	79,990,974	79,711,641
TOTAL	0	0	0	51,422,952	50,464,888	126,808,347	125,925,396	125,077,762	192,942,434	192,161,255	191,411,323	190,691,389	190,000,252	189,336,760
COSTS ($):														
ON-PEAK	0	0	0	680,286	688,861	2,602,527	2,661,466	2,728,360	4,110,759	4,185,113	4,281,239	4,345,416	4,499,872	4,735,533
OFF-PEAK	0	0	0	494,656	500,891	1,892,374	1,935,230	1,983,871	2,989,053	3,043,118	3,113,015	3,159,680	3,271,989	3,443,345
TOTAL	0	0	0	1,174,941	1,189,753	4,494,901	4,596,697	4,712,231	7,099,812	7,228,231	7,394,254	7,505,096	7,771,860	8,178,878
BALANCE (KWH):														
ON-PEAK	0	120,443,140	120,088,270	114,319,580	116,452,063	73,098,555	69,372,845	64,517,884	43,520,554	45,454,949	45,606,991	42,574,638	37,613,656	38,841,355
OFF-PEAK	0	69,266,402	69,062,317	61,261,753	62,900,105	32,012,689	32,203,846	30,289,948	8,044,472	9,703,801	11,369,932	12,572,633	12,267,812	13,348,840
TOTAL	0	189,709,541	189,150,588	175,581,333	179,352,168	105,111,244	101,576,691	94,807,831	51,565,026	55,158,750	56,976,923	55,147,271	49,881,468	52,190,195

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU
50% RENEWABLE ENERGY

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION III - PROJECTED RESOURCES:						
(A) RENEWABLE PORTFOLIO STANDARD (K'						
ON-PEAK	20,301,223	21,920,070	23,543,727	25,173,046	26,808,860	28,451,982
OFF-PEAK	3,742,451	4,435,562	5,129,640	5,825,078	6,559,504	7,398,750
TOTAL	24,043,674	26,355,631	28,673,368	30,998,125	33,368,363	35,850,732
COSTS ($):						
ON-PEAK	1,971,306	2,162,002	2,268,638	2,426,541	2,680,413	3,007,294
OFF-PEAK	375,676	452,089	510,880	580,631	677,394	804,017
TOTAL	2,346,982	2,614,090	2,779,518	3,007,172	3,357,807	3,811,311
						$106
(B) CDWR CONTRACT ENERGY (KWH):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
COSTS ($):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
BALANCE (KWH):						
ON-PEAK	149,343,797	150,254,563	151,198,463	152,175,214	153,184,562	154,226,278
OFF-PEAK	93,819,769	94,581,429	95,363,943	96,167,247	96,954,044	97,658,838
TOTAL	243,163,566	244,835,992	246,562,406	248,342,460	250,138,606	251,885,116
(C) POWER PRODUCTION (KWH):						
ON-PEAK	109,256,327	108,902,287	108,562,408	108,236,124	107,922,891	107,622,188
OFF-PEAK	79,443,481	79,186,048	78,938,912	78,701,661	78,473,900	78,255,250
TOTAL	188,699,808	188,088,334	187,501,319	186,937,785	186,396,792	185,877,439
COSTS ($):						
ON-PEAK	4,941,471	5,047,283	5,064,537	5,138,921	5,300,969	5,517,233
OFF-PEAK	3,593,089	3,670,028	3,682,573	3,736,660	3,854,490	4,011,742
TOTAL	8,534,560	8,717,311	8,747,110	8,875,581	9,155,459	9,528,976
BALANCE (KWH):						
ON-PEAK	40,087,470	41,352,276	42,636,055	43,939,090	45,261,671	46,604,090
OFF-PEAK	14,376,288	15,395,382	16,425,032	17,465,586	18,480,143	19,403,587
TOTAL	54,463,758	56,747,658	59,061,086	61,404,676	63,741,814	66,007,678

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES
50% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
(D) LONG-TERM CONTRACT PURCHASES (KWH):														
ON-PEAK	0	101,440,000	101,440,000	101,440,000	101,440,000	50,720,000	50,720,000	50,720,000	25,360,000	25,360,000	25,360,000	25,360,000	25,360,000	25,360,000
OFF-PEAK	0	55,320,000	55,320,000	55,320,000	55,320,000	18,440,000	18,440,000	18,440,000	0	0	0	0	0	0
TOTAL	0	156,760,000	156,760,000	156,760,000	156,760,000	69,160,000	69,160,000	69,160,000	25,360,000	25,360,000	25,360,000	25,360,000	25,360,000	25,360,000
COSTS ($):														
ON-PEAK	0	7,714,065	7,714,065	8,392,797	8,392,797	4,512,142	4,512,142	4,512,142	1,934,034	1,934,034	2,186,248	2,186,248	2,186,248	2,186,248
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	7,714,065	7,714,065	8,392,797	8,392,797	4,512,142	4,512,142	4,512,142	1,934,034	1,934,034	2,186,248	2,186,248	2,186,248	2,186,248
BALANCE (KWH):														
ON-PEAK	0	19,003,140	18,648,270	12,879,580	15,012,063	22,378,555	18,652,845	13,797,884	18,160,554	20,094,949	20,246,991	17,214,638	12,253,656	13,481,355
OFF-PEAK	0	13,946,402	13,742,317	5,941,753	7,580,105	13,572,689	13,763,846	11,849,948	8,044,472	9,703,801	11,369,932	12,572,633	12,267,812	13,348,840
TOTAL	0	32,949,541	32,390,588	18,821,333	22,592,168	35,951,244	32,416,691	25,647,831	26,205,026	29,798,750	31,616,923	29,787,271	24,521,468	26,830,195
(E) SHORT-TERM CONTRACT PURCHASES (KWH):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COSTS ($):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BALANCE (KWH):														
ON-PEAK	0	19,003,140	18,648,270	12,879,580	15,012,063	22,378,555	18,652,845	13,797,884	18,160,554	20,094,949	20,246,991	17,214,638	12,253,656	13,481,355
OFF-PEAK	0	13,946,402	13,742,317	5,941,753	7,580,105	13,572,689	13,763,846	11,849,948	8,044,472	9,703,801	11,369,932	12,572,633	12,267,812	13,348,840
TOTAL	0	32,949,541	32,390,588	18,821,333	22,592,168	35,951,244	32,416,691	25,647,831	26,205,026	29,798,750	31,616,923	29,787,271	24,521,468	26,830,195

CITY OF EMERYVILLE
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU
50% RENEWABLE ENERGY

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(D) LONG-TERM CONTRACT PURCHASES (KV						
ON-PEAK	25,360,000	25,360,000	25,360,000	25,360,000	25,360,000	25,360,000
OFF-PEAK	0	0	0	0	0	0
TOTAL	25,360,000	25,360,000	25,360,000	25,360,000	25,360,000	25,360,000
COSTS ($):						
ON-PEAK	2,186,248	2,556,907	2,556,907	2,556,907	2,556,907	2,556,907
OFF-PEAK	0	0	0	0	0	0
TOTAL	2,186,248	2,556,907	2,556,907	2,556,907	2,556,907	2,556,907
BALANCE (KWH):						
ON-PEAK	14,727,470	15,992,276	17,276,055	18,579,090	19,901,671	21,244,090
OFF-PEAK	14,376,288	15,395,382	16,425,032	17,465,586	18,480,143	19,403,587
TOTAL	29,103,758	31,387,658	33,701,086	36,044,676	38,381,814	40,647,678
(E) SHORT-TERM CONTRACT PURCHASES (K						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
COSTS ($):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
BALANCE (KWH):						
ON-PEAK	14,727,470	15,992,276	17,276,055	18,579,090	19,901,671	21,244,090
OFF-PEAK	14,376,288	15,395,382	16,425,032	17,465,586	18,480,143	19,403,587
TOTAL	29,103,758	31,387,658	33,701,086	36,044,676	38,381,814	40,647,678

Appendix F – Pro Forma Summary With Alternative Supply Portfolios

Alternative Scenario 1

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	34.7	2.7	1.8	11.4	0.3	0.2	51.1	52.4	1.3	2%
2007	35.5	2.9	1.8	10.8	0.3	0.2	51.5	53.6	2.1	2%
2008	36.4	3.0	1.9	11.1	0.3	0.2	52.9	55.9	3.0	3%
2009	38.2	3.2	1.9	7.9	0.3	0.2	51.7	57.5	5.8	6%
2010	47.1	3.5	1.9	7.3	0.3	0.3	60.3	60.7	0.4	0%
2011	48.8	3.7	2.0	7.5	0.3	0.3	62.6	63.0	0.4	0%
2012	50.2	3.9	2.0	7.8	0.3	0.3	64.4	65.4	1.0	1%
2013	51.4	4.0	2.0	3.5	0.4	0.3	61.6	62.4	0.8	1%
2014	52.7	4.2	2.1	3.6	0.4	0.3	63.2	64.5	1.3	1%
2015	61.3	4.4	2.1	3.6	0.4	0.3	72.1	67.1	(5.0)	-4%
2016	62.5	4.6	2.1	3.7	0.4	0.3	73.6	69.1	(4.6)	-4%
2017	64.5	4.8	2.2	3.8	0.4	0.3	76.0	72.9	(3.1)	-3%
2018	67.4	5.2	2.2	3.8	0.4	0.3	79.4	78.6	(0.8)	-1%
2019	70.1	5.6	2.3	3.9	0.5	0.4	82.7	83.9	1.2	1%
2020	80.4	5.8	2.3	4.0	0.5	0.4	93.4	87.1	(6.3)	-4%
2021	81.5	6.0	2.3	4.1	0.5	0.4	94.7	88.3	(6.4)	-4%
2022	83.1	6.1	2.4	3.9	0.5	0.4	96.5	90.8	(5.7)	-4%
2023	85.7	6.5	2.4	-	0.6	0.4	95.5	91.7	(3.9)	-2%
2024	89.0	6.9	2.5	-	0.6	0.4	99.3	97.7	(1.7)	-1%
Total	1,140.5	87.0	40.0	101.7	7.6	5.9	1,382.7	1,362.6	(20.2)	-1%

Alternative Scenario 2

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	34.7	2.7	1.8	11.4	0.3	0.2	51.1	52.4	1.3	2%
2007	35.5	2.9	1.8	10.8	0.3	0.2	51.5	53.6	2.1	2%
2008	36.4	3.0	1.9	11.1	0.3	0.2	52.9	55.9	3.0	3%
2009	38.2	3.2	1.9	7.9	0.3	0.2	51.7	57.5	5.8	6%
2010	47.1	3.5	1.9	7.3	0.3	0.3	60.3	60.7	0.4	0%
2011	48.8	3.7	2.0	7.5	0.3	0.3	62.6	63.0	0.4	0%
2012	50.2	3.9	2.0	7.8	0.3	0.3	64.4	65.4	1.0	1%
2013	51.4	4.0	2.0	3.5	0.4	0.3	61.6	62.4	0.8	1%
2014	52.7	4.2	2.1	3.6	0.4	0.3	63.2	64.5	1.3	1%
2015	61.3	4.4	2.1	3.6	0.4	0.3	72.1	67.1	(5.0)	-4%
2016	62.5	4.6	2.1	3.7	0.4	0.3	73.6	69.1	(4.6)	-4%
2017	64.5	4.8	2.2	3.8	0.4	0.3	76.0	72.9	(3.1)	-3%
2018	67.4	5.2	2.2	3.8	0.4	0.3	79.4	78.6	(0.8)	-1%
2019	70.1	5.6	2.3	3.9	0.5	0.4	82.7	83.9	1.2	1%
2020	80.4	5.8	2.3	4.0	0.5	0.4	93.4	87.1	(6.3)	-4%
2021	81.5	6.0	2.3	4.1	0.5	0.4	94.7	88.3	(6.4)	-4%
2022	83.1	6.1	2.4	3.9	0.5	0.4	96.5	90.8	(5.7)	-4%
2023	85.7	6.5	2.4	-	0.6	0.4	95.5	91.7	(3.9)	-2%
2024	89.0	6.9	2.5	-	0.6	0.4	99.3	97.7	(1.7)	-1%
Total	1,140.5	87.0	40.0	101.7	7.6	5.9	1,382.7	1,362.6	(20.2)	-1%

Alternative Scenario 3

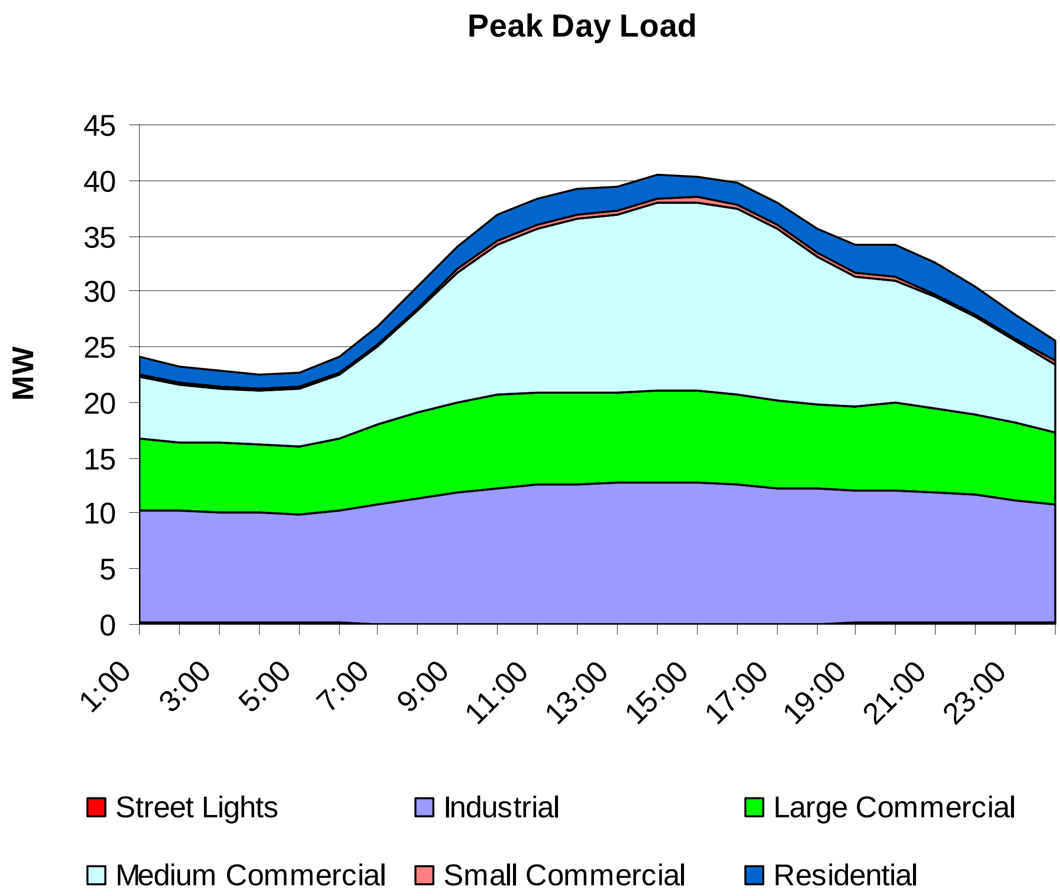
Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	35.4	2.7	1.8	11.4	0.3	0.2	51.8	52.4	0.6	1%
2007	36.5	2.9	1.8	10.8	0.3	0.2	52.5	53.6	1.1	1%
2008	30.5	3.0	1.9	11.1	0.3	8.2	55.0	55.9	0.9	1%
2009	31.9	3.2	1.9	7.9	0.3	8.2	53.4	57.5	4.1	4%
2010	33.1	3.5	1.9	7.3	0.3	9.2	55.2	60.7	5.5	6%
2011	34.6	3.7	2.0	7.5	0.3	9.0	57.1	63.0	5.8	6%
2012	36.2	3.9	2.0	7.8	0.3	8.9	59.1	65.4	6.4	6%
2013	37.7	4.0	2.0	3.5	0.4	8.7	56.3	62.4	6.1	6%
2014	39.2	4.2	2.1	3.6	0.4	8.6	58.0	64.5	6.5	6%
2015	43.5	4.4	2.1	3.6	0.4	8.4	62.5	67.1	4.6	4%
2016	45.0	4.6	2.1	3.7	0.4	8.3	64.1	69.1	5.0	4%
2017	47.3	4.8	2.2	3.8	0.4	8.1	66.6	72.9	6.4	5%
2018	50.3	5.2	2.2	3.8	0.4	7.9	70.0	78.6	8.7	7%
2019	53.4	5.6	2.3	3.9	0.5	7.7	73.3	83.9	10.6	8%
2020	58.7	5.8	2.3	4.0	0.5	7.5	78.8	87.1	8.3	6%
2021	60.2	6.0	2.3	4.1	0.5	7.3	80.3	88.3	8.0	5%
2022	62.2	6.1	2.4	3.9	0.5	7.0	82.2	90.8	8.5	6%
2023	65.2	6.5	2.4	-	0.6	6.8	81.4	91.7	10.3	7%
2024	68.9	6.9	2.5	-	0.6	6.5	85.3	97.7	12.3	8%
Total	869.8	87.0	40.0	101.7	7.6	136.7	1,242.9	1,362.6	119.7	5%

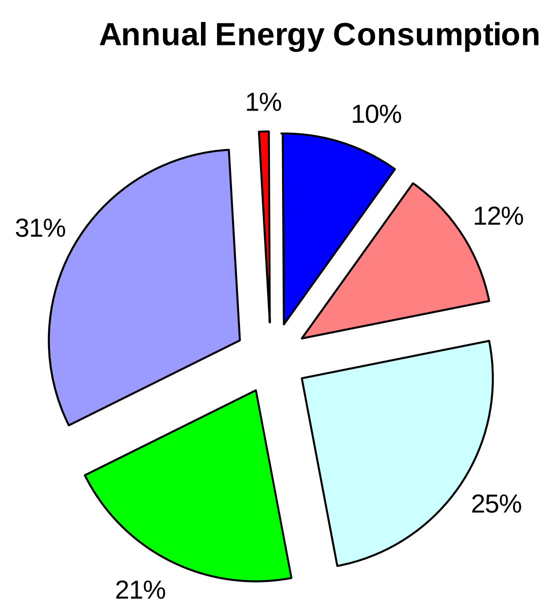
Alternative Scenario 4

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	33.6	2.7	1.8	11.4	0.3	0.2	50.0	52.4	2.5	3%
2007	34.4	2.9	1.8	10.8	0.3	0.2	50.4	53.6	3.2	3%
2008	34.3	3.0	1.9	11.1	0.3	4.2	54.8	55.9	1.1	1%
2009	35.7	3.2	1.9	7.9	0.3	4.2	53.2	57.5	4.4	5%
2010	34.8	3.5	1.9	7.3	0.3	6.4	54.1	60.7	6.7	7%
2011	36.3	3.7	2.0	7.5	0.3	6.3	56.1	63.0	6.9	7%
2012	38.0	3.9	2.0	7.8	0.3	6.2	58.2	65.4	7.3	7%
2013	39.5	4.0	2.0	3.5	0.4	6.1	55.5	62.4	6.9	6%
2014	41.1	4.2	2.1	3.6	0.4	6.0	57.2	64.5	7.3	7%
2015	45.4	4.4	2.1	3.6	0.4	5.9	61.8	67.1	5.3	5%
2016	46.9	4.6	2.1	3.7	0.4	5.8	63.5	69.1	5.6	5%
2017	49.4	4.8	2.2	3.8	0.4	5.7	66.3	72.9	6.6	5%
2018	53.0	5.2	2.2	3.8	0.4	5.6	70.3	78.6	8.3	6%
2019	56.5	5.6	2.3	3.9	0.5	5.4	74.2	83.9	9.7	7%
2020	62.1	5.8	2.3	4.0	0.5	5.3	80.0	87.1	7.1	5%
2021	63.3	6.0	2.3	4.1	0.5	5.1	81.3	88.3	7.0	5%
2022	65.2	6.1	2.4	3.9	0.5	5.0	83.2	90.8	7.6	5%
2023	68.2	6.5	2.4	-	0.6	4.8	82.5	91.7	9.2	6%
2024	72.1	6.9	2.5	-	0.6	4.7	86.7	97.7	11.0	7%
Total	909.8	87.0	40.0	101.7	7.6	93.0	1,239.2	1,362.6	123.4	5%

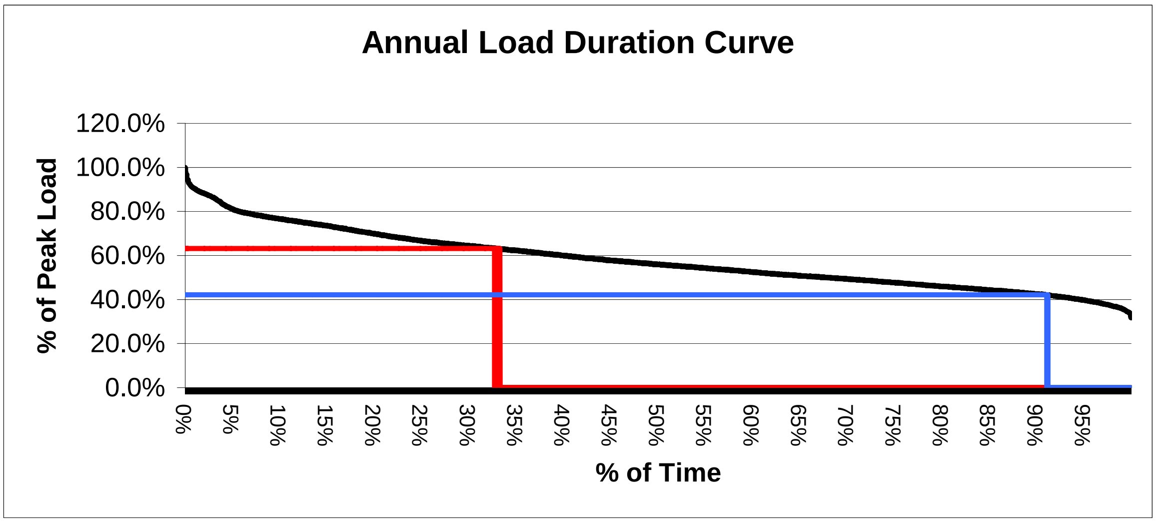
Appendix G – Electric Customers and Load Analysis

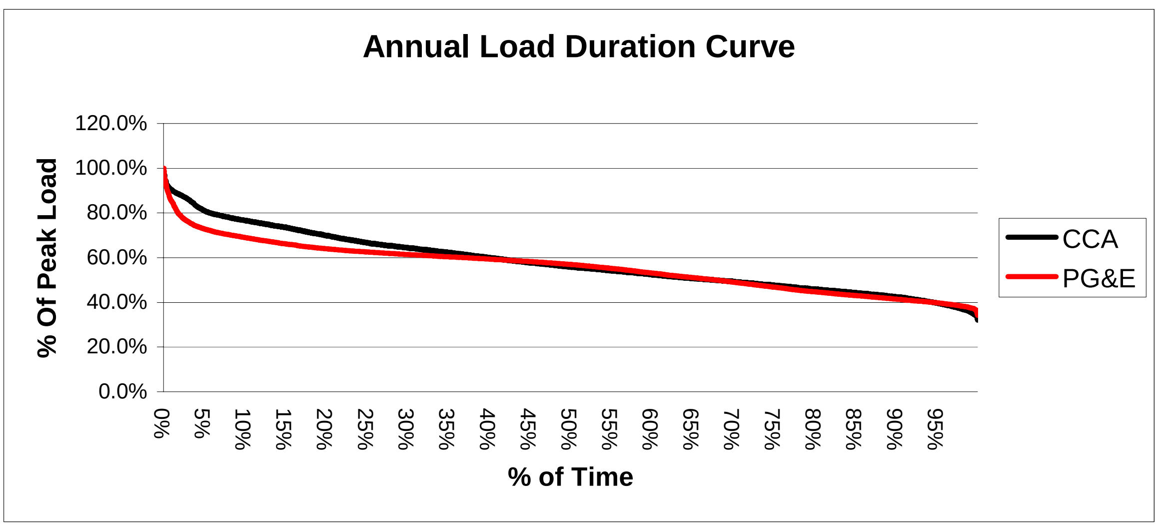
City of Emeryville
Electric Demand and Energy Consumption



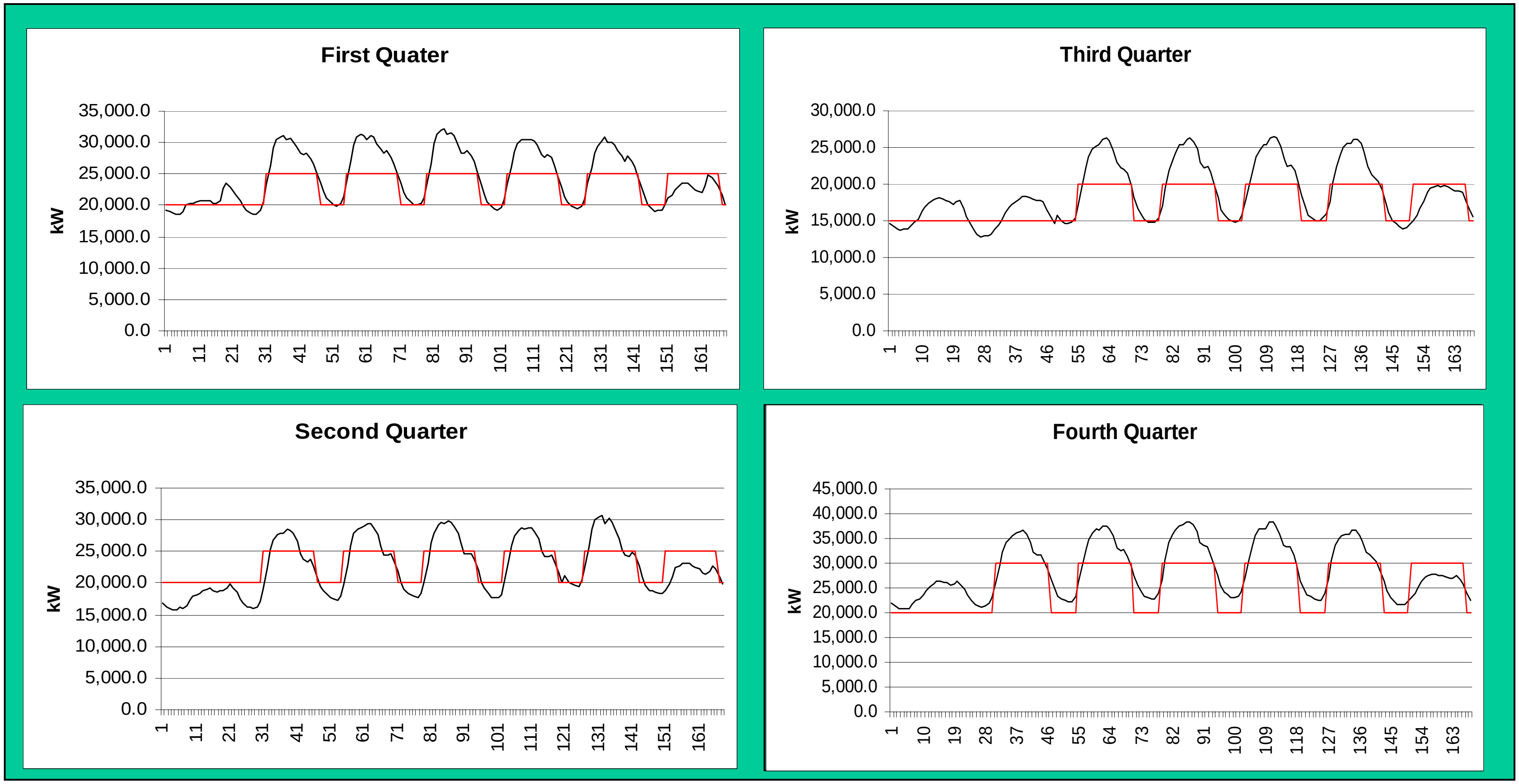


City Load Characteristics Compared to PG&E System-Wide





Emeryville Load Plots and Power Blocks



Quarter	7X24	6X16	Dumped kWh	Req. kWh	Qtr % kWk
1	20000	5000	2,207,809	50,644,618	4.36%
2	20000	5000	4,107,822	47,621,695	8.63%
3	15000	5000	271,959	52,231,284	0.52%
4	20000	10000	4,134,295	55,198,889	7.49%
			10,721,885	205,696,487	5.21%

Energy Purchases (kWh)

7X24	164,160,000	75.9%
6X16	30,800,000	14.2%
Spot On-Peak	14,983,874	6.9%
Spot Off-Peak	6,474,498	3.0%
Total	216,418,372	100.0%

Total Energy	Spot Purchases
205,696,487	9.9%

Appendix H – Implementation Schedule

The City could begin providing electric service to customers in the community as early as 2006 by following the timeline shown below:

COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PROCESS AND TIMELINE

TASK	ESTIMATED START DATE
1 Feasibility Assessment and Evaluation	**3/10/05 – 5/7/05**
1.1 Review Final Feasibility Report	3/10/05
1.2 Conduct Public Workshop(s) and council sessions to consider proceeding to implementation	4/14/05
1.3 Decision to Develop CCA Implementation Plan	5/7/05
2 Implementation Plan Development	**5/14/05 – 7/30/05**
2.1 Obtain Billing Data From Utility	5/28/05
2.2 Issue Request For Qualifications/Offers To Suppliers	6/4/05
2.3 Identify uncommitted generation projects and negotiate participation, if applicable	6//4/05
2.4 Develop program structure, organization, operations plans and funding	6/11/06
2.5 Document participant rights and responsibilities	6/11/05
2.6 Select Preferred electric supplier(s) and	6/25/05

TASK	ESTIMATED START DATE
partners; Evaluate and document their financial, technical and operational capabilities	
2.7 Develop preliminary energy supply resource portfolio	6/25/05
2.8 Perform Rate Design (cost allocation methodology and disclosure)	7/2/05
2.9 Complete Draft Implementation Plan	7/9/05
2.10 Conduct Public Workshop(s) on Draft Implementation Plan	7/16/05
2.11 Issue Resolution Adopting Implementation Plan	7/30/05
3 CPUC Implementation Plan Filing	**8/6/05 – 11/5/05**
3.1 File Implementation Plan and Statement of Intent with CPUC	8/6/05
3.2 Respond to information requests from CPUC or intervenors	8/13/05
3.3 Participate as required in CPUC process to support implementation plan	8/13/05
3.4 Monitor CPUC decisions	11/5/05
4 Initiate CCA Startup Activities	**8/13/05 – 12/10/05**
4.1 Conduct Recruiting and Staffing	

TASK		ESTIMATED START DATE
4.2	Develop informational and program marketing materials	8/13/05
4.3	Establish call center for customer inquiries	8/20/05
4.4	Develop in house capabilities or execute contracts for performance of operational services:	8/20/05
	- Electronic data interchange with utility	-
	- Customer bill calculations	-
	- Scheduling coordinator services	-
	- Application of statistical load profiles and submittal of hourly usage data for CAISO settlements	-
	- Resource planning, portfolio and risk management	-
	- Ratemaking	-
	- Load forecasting	-
	- Wholesale settlements	-
	- Credit and finance	-
	- Information Technology	-
	- Legal and regulatory support	-
4.5	Contact key customers to explain program, obtain commitment, and release customer information	8/27/05
4.6	Execute contracts for electric supply	11/12/05
4.7	Update program rates	11/12/05
4.8	Obtain financing for program capital	11/12/05

TASK	ESTIMATED START DATE
requirements	
4.9 Execute service agreement with utility[17]	11/19/05
4.10 Complete utility technical testing	11/26/05
4.11 Establish account with utility	12/3/05
4.12 Register with CPUC, post bond or demonstrate insurance	12/10/05
5 Customer Notification and Enrollment	**12/17/05 – 2/19/06**
5.1 Send first opt-out notice to eligible and ineligible customers	12/17/05
5.2 Send second opt-out notice to eligible and ineligible customers	1/21/06
5.3 Process customer opt-out requests and enroll customers	1/28/06
5.4 Submit notification certification to CPUC	2/5/06
5.5 Notify utility when CCA service will begin to initiate account transfer	2/5/06
5.6 Obtain updated billing data from utility	2/12/06
5.7 Update load forecasts and supply plan	2/19/06
6 CCA Operations	**3/2/06 – Ongoing**
6.1 Activate energy supply resource plan	2/2/06
6.2 Commence mass account transfer	3/3/06

[17] The City, as a CCA operator, will need to establish a legal relationship with PG&E. It is anticipated that a service agreement will include processes for information exchange including electronic data interchange, procedures for settling financial transactions, treatment of customer bill payment funds transfer, credit terms, access to confidential customer information, audit provisions, and regulatory oversight and complaint processes.

TASK	ESTIMATED START DATE
6.3 Manage supply portfolio and risk management (ongoing)	3/3/06
- Prepare daily load forecasts	3/3/06
- Balance portfolio with purchases and sales	3/3/06
- Schedule loads and resources	3/3/06
- Monitor credit of suppliers and mark to market exposure	3/3/06
- Maintain risk controls on supply portfolio	3/3/06
6.4 Perform Account Management, Billing and Settlements (ongoing)	3/3/06
- Process customer transfers into and out of program	3/4/06
- Receive and respond to customer inquiries	3/4/06/
- Pay electric suppliers	3/19/06
- Obtain customer meter data from IOU	4/2/06
- Prepare bill calculations	4/2/06
- Provide bill amounts to IOU	4/2/06
- Apply statistical load profiles to meter data and submit to ISO for settlement	4/2/06
- Pay IOU transaction fees	4/2/06
- Receive remittances from IOU from customer collections	4/19/06
- Verify ISO settlement statements and	5/6/06

TASK	ESTIMATED START DATE
pay ISO charges	
6.5 Distribute third opt-out notice	4/2/06
6.6 Complete mass account transfer	4/2/06
6.7 Process opt-outs	4/3/06
6.8 Prepare operating statements and financial reports (ongoing)	4/19/06
6.9 Distribute fourth opt-out notice	5/6/06
6.10 Process opt-outs	5/7/06