




Office of the City Manager

INFORMATION CALENDAR

March 7, 2006

To: Honorable Mayor and
Members of the City Council

From:  Phil Kamlarz, City Manager

Submitted by: Stephen Barton, Director, Housing Department
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Subject: Community Choice Aggregation

INTRODUCTION

This report provides information regarding the Council workshop on Community Choice Aggregation (CCA). The companion action report on the regular agenda for the March 7, 2006 meeting concerns a contract amendment for the development of a detailed business plan and feasibility study of CCA, referred to as Phase II.

SUMMARY

This report describes the current regulatory and economic landscape in which power is currently provided to City residents by PG&E, the legislation which authorizes local governments to create a CCA to provide electricity and power to their residents, a comparison of the structural advantages of power supplies from a CCA and PG&E, a description of the study process, a preliminary assessment of the possible benefits and risks to both taxpayers and ratepayers from a CCA, the City's phased approach to assessing whether to proceed further, and the possible next steps that the Council could take in this regard. One such option is to accept the recommendation of the companion Action report on tonight's regular agenda that asks that the City Manager be authorized to execute a contract to complete a study that will produce a final recommendation on whether or not to start a CCA. In taking that action the Council may direct the City Manager to modify the proposed direction of the study.

CURRENT SITUATION AND ITS EFFECTS

Electricity service in Berkeley is currently partially regulated. PG&E currently provides electric power commodity to most customers in Berkeley. Approximately 41% of the power comes from plants owned and operated by PG&E (mostly Diablo Canyon and hydropower facilities); it is projected that PG&E will generate 36% of its own power by 2017. The balance comes from contract or spot market purchases. PG&E's rates are set so that the company can earn a return on its investment in its power plants and recoup its expenses on power generation and power purchases. The costs associated with Diablo Canyon and its hydroelectric plants are low and relatively stable. Its power purchase contracts, which are staggered, are subject to prevailing market conditions when the contracts are negotiated. Spot market purchases are directly related to the prevailing market but are a relatively minor share of PG&E's portfolio. Changes in the

market rate for power, due to the availability of supply (i.e., capacity) or changes in operating costs (e.g., fuel) are passed on to consumers through rates. PG&E shareholder risks are limited to catastrophic failures (e.g., the recent bankruptcy) and actions deemed imprudent by State regulators. PG&E rates currently include payments related to bonds and other expenses associated with the energy crisis.

PG&E retail rates are regulated by the California Public Utilities Commission (CPUC). The CPUC has five commissioners appointed by the Governor. However, the CPUC has no jurisdiction over wholesale rates. All wholesale suppliers (including those selling to PG&E) are subject to limited regulation by the Federal Energy Regulatory Commission (FERC). FERC generally allows the market to establish prices and only intervenes if there is evidence of illegal behavior. FERC's reluctance to intervene on the behalf of consumers was illustrated during the 2000 California energy crisis.

Approximately 12% of PG&E's electricity now comes from renewable sources. PG&E is required to acquire 20% of its resources from renewables by 2017. The State is currently considering whether to increase this percentage so that utilities must achieve 33% renewables by 2020.

In each of the next several years PG&E will be signing long-term energy contracts, including contracts at premium prices to meet the State renewables standard. These contracts will place upward pressure on PG&E's rates. PG&E increased residential rates by 11% on January 1, 2006 and further rate increases are likely. Electric customers within the City will be responsible for the costs of PG&E's electricity procurement activities until such time as customers are given the opportunity to join a CCA.

BACKGROUND

History of the Project

This project was initiated in 2003 based upon 1) a change in State law (AB 117, Migden, 2002) that enabled local governments to form CCAs to deliver power to their residents and businesses; 2) the interest of several other cities to investigate CCA; and 3) the availability of State and Federal grant funds, through the Local Government Commission to support such an investigation. In response to AB 117, the City conducted a competitive solicitation for the study of CCA. The contract was awarded to Navigant Consulting, based on their qualifications, proposed scope of work and funds leveraged from the California Energy Commission and US Department of Energy.

In order to minimize expense commitments, this project is being conducted in three incremental phases. Phase I, was a feasibility study based on market assumptions that was independently reviewed and updated. The Study was delivered to Council in April 2005. The independent review of the Phase I study and updated financial proforma are attached as Attachments 1 and 2.

Phase II will entail Navigant, the Phase I consultant, conducting a rigorous verification of the Phase I economic assumptions with emphasis on testing of risk tolerances, and a detailed business plan. Either during or before the consultant's Phase II activities, the City contemplates

retaining expert legal advice to advise the City as to its legal risks and burdens in creating a CCA, including the ability of the CCA to issue bonds to finance its activities, and to do so without jeopardizing the City's General Fund or other assets. The City will also undertake market studies to test whether a sufficient number of customers are likely to remain as CCA customers since the new legislation allows them to opt out both at the start and periodically every two years. The goal of Phase II is to generate enough information to determine whether to proceed to Phase III and create a CCA.

Phase III would consist of those tasks necessary to start a CCA. There are several points, or "thresholds," either prior to or in conjunction with Phase II, that will allow the City to make a decision to proceed or not to proceed with the CCA project.

A consortium of local governments¹, with supplemental funding from State and Federal sources, participated in Phase I. Based on the Phase I feasibility study, Oakland and Emeryville have executed contracts for Phase II and authorized Navigant to begin initial tasks. The proposed action would include the City of Berkeley in this phase of the study. Berkeley's share would be 23% of the total costs. The City's costs for this phase include \$72,992 in expenses for the Navigant amendment and \$91,200 in other expenses. Based on Council's feedback and the independent legal and marketing reviews that Berkeley would be undertaking as part of Phase II, the City might wish to modify the scope of the Navigant contract and it would then not be parallel with the Emeryville and Oakland agreements.

The City of San Francisco is conducting Phase II activities (with a different contractor). The City of Chula Vista is actively preparing plans for creating a CCA. Both cities are further along in this process than Berkeley. Their participation in the regulatory process and advance work on planning has been and will probably continue to be critical to advancing the feasibility of CCA and informing the City's efforts. The City of Pleasanton, alone or with other Tri-Valley jurisdictions, is also in the process of evaluating the feasibility of forming a CCA. The City of Fresno and 12 other Central Valley cities and counties are currently preparing an implementation plan for CCA. CCAs are operating in Massachusetts, New Jersey, Rhode Island and Ohio.

Legislation Regarding CCAs

AB 117 authorizes local governments and joint power authorities to provide limited retail electric service to all customers within the jurisdictions unless the customer chooses to "opt out" of the CCA during a 60-day notice period. CCAs are authorized to provide electricity; the investor-owned utilities (IOUs) would continue to own and operating the transmission and distribution system. The purpose of AB 117 was to reduce marketing costs to a point where cities and counties might be able to compete with PG&E for retail service.

AB 117 prohibited CCAs from having any adverse impact on the remaining IOU ratepayers. In our case this means the remaining PG&E ratepayers. Pursuant to this requirement, the California Public Utilities Commission (CPUC) has established that the CCA's ratepayers bear their share of the ongoing cost of the California energy crisis and imposed an "exit fee" on CCAs if the

¹ Berkeley, Oakland, Emeryville, Vallejo, Richmond, Marin, Pleasanton

IOU's (e.g. PG&E) rates are adversely affected by ratepayers who leave PG&E to become part of the CCA's ratepayers. Formulae for the exit fee and other fees to the IOUs have been adopted by the CPUC. The Public Utilities Commission is still in the process of reviewing the tariffs submitted by the IOUs related to these fees. The final tariffs, if they differ from the CPUC's orders, may have an effect on the risk and viability of any such CCA. The IOU is also allowed to charge the CCA for the services it provides in enabling the CCA to deliver services to its customers. Again the tariffs allowed by the PUC can affect what a CCA would have to pay PG&E and thus the CCA's viability. In essence, the CCA will be in competition with PG&E for rate paying customers and purchasing power supplies.

No California City has yet created and operated a CCA since this legislation was adopted, although several California cities are conducting investigations. There is, however, a long history of local government provision of power and investment in generation, including, for example, Alameda, Sacramento, Palo Alto and Los Angeles.

Objectives of the Project

The City's investigation of CCA is grounded in the pursuit of the following policy objectives:

- It is projected that a net CO₂ reduction of 40% from electrical generation can be achieved by forming a CCA that invests in renewable power generation. This represents over 50% of the City's stated policy objective of reducing all community emissions by 15%.
- Medium and long-term rates can be more stable and probably lower than PG&E rates would be under PG&E, based on the CCA's lower cost of capital, lower reliance of fossil fuels and higher share of plant dedicated to local ratepayers.

Comparative Structural Advantages of CCA and PG&E To The Power Supplier

Viewed from the point of view of an entity that is engaged in supplying power to its customers, the Phase I study states that CCA's have a structural advantage over PG&E due to their access to tax-exempt bond financing, an assumption that should be tested by obtaining expert legal advice, should the City Council proceed with exploring CCA. Private power generators net cost of capital is estimated at 12.9%, while a CCA's cost is estimated at 5.5%, assuming the availability of tax exempt financing, and the lack of shareholder returns and income taxes. Therefore, if a CCA makes a major investment in publicly-owned and operated generation plants, its cost of power will be lower than those of private generators selling power to PG&E. The Phase I study assumes that if tax-exempt financing is available, it will tend to favor construction of renewable generating plants since such plants have a high initial capital outlay but low operating costs compared to conventional energy sources. The Phase I study assumes that 50% of the CCA's power will come from its own plants. The balance will come from private contracts. Thus, the viability of a CCA supplier of power to its customers turns on its ability to invest in the construction and operation of a power generation plant. Thus any evaluation of the risk of a CCA supplying energy to its customers must also consider the risk of constructing and operating the power generation plants that are critical to the CCA's viability.

Again, viewed from the perspective of the entity supplying power, an East Bay CCA also has the advantage of having a relatively predictable load. The East Bay climate is not as weather sensitive as PG&E's average and therefore somewhat more predictable.

PG&E's primary advantage is that it has very low-cost power from the hydropower and nuclear facilities that it owns. These plants operate at a cost far less than anything available on the market and CCA customers would have no access to these assets. However, these plants have limited output and PG&E must rely on private merchant power plants for a large portion of its portfolio.

PG&E also has the advantage of having a fully developed organization, considerable market power and a large customer base over which it can spread risk.

The central economic question is whether the total cost of the CCA's supply portfolio will be less than the total cost of PG&E's supply portfolio. PG&E's portfolio will consist of low-cost hydroelectric and nuclear power, PG&E fossil-fueled power and a variety of power purchase contracts for traditional and renewable power. The CCA's portfolio will consist of moderate-cost renewable plants and a variety of power purchase contracts for traditional power. The economics of a successful CCA hinge on assumptions that the premium PG&E will be paying for renewable energy contracts will more than offset the advantage that its owned generation has over CCA-owned generation and that contract costs for traditional power will be about the same for PG&E and a CCA.

The relatively large percentage of CCA-owned renewable generation gives the CCA the potential to have more stable rates over time but in the first two-to three years, the financial analysis indicates that rates may be about 2% higher than PG&E rates. Renewable energy is not subject to fluctuations in fuel prices and local ownership ensures that capacity is available even in tight supply markets.

Of lesser importance, is the fact that PG&E ratepayers in Berkeley subsidize ratepayers in other communities. Under a CCA, some of these subsidies would be eliminated. PG&E overcharges medium and small commercial users and undercharges residential users. Since Berkeley has relatively more commercial load than residential (relative to PG&E system averages), this results in a subsidy from Berkeley to primarily residential communities. It is likely that this subsidy will be phased out over several years but it may help the CCA during initial years.

Phase I

The City Council authorized funds for the preparation of a feasibility study of creating a CCA in Berkeley referred to as Phase I. Phase I was completed in April 2005 and presented to the City Council. It contemplated that a CCA would be engaged in the business of competing to purchase power from power generators, making substantial investments in power generation plants by issuance of revenue bonds and then selling such power to its ratepayers in competition with other power suppliers such as PG&E and PG&E's suppliers.

The Phase I feasibility study was succeeded by an independent review of its findings and then updated. The update indicates that under a CCA acquiring 50% of its energy from renewable sources by 2017, the initial rates charged customers by a Berkeley CCA are likely to be 2% higher than those of the CCA's competitors but that over time it is possible that a CCA may supply power at rates lower than its competition, or at least create greater rate stability.

This analysis does not include the benefits of scale that would be achieved by implementing the CCA program in partnership with the cities of Oakland and Emeryville. It also does not include any consideration of strategies that may be able keep rates at or below PG&E rates; for example, by modifying the timing of program implementation or phasing customer enrollment and program operations.

The analysis is contingent upon access to cost-based power developed by the CCA, perhaps in partnership with an existing public agency, such as the Sacramento Municipal Utilities District, the Northern California Public Power Agency, and financing by the CCA using tax-exempt bonds. Berkeley's share of this investment would be about \$130 million over the next ten to twenty years; the cost for Berkeley, Oakland and Emeryville together would be about \$700 million. For reference purposes, this is equivalent to approximately two-years of current community-wide PG&E electricity bills. It is this investment with tax-exempt public financing, which gives the CCA its potential economic advantage over PG&E. Without such a major investment in new power generating plants, CCA rates would almost certainly be higher than PG&E rates. The investment also provides relative rate stability, since the CCA would own the assets and operating costs will be minimal (i.e., renewables do not use fuel and are therefore more price stable). This investment would cover approximately 50% of the community's energy needs; the balance would come from power purchase contracts for conventional sources of power.

The analysis is contingent upon a variety of general assumptions that would be the subject of a Phase II study. Some of the major assumptions are discussed in the Risks section below.

Phase II

Many more detailed questions remain to be answered in this next phase relating to the actual economic feasibility and risks to ratepayers and taxpayers entailed in the City venturing into the power generation, purchasing, and rate setting business. Staff, Navigant, and independent market research consultants will perform this work and will be advised by independent legal counsel, technical experts, and stakeholder representatives. Phase II would also include a public outreach and workshop component. Should the Council choose to proceed with Phase II in its entirety it would receive a Phase II report and then decide whether or not to proceed to create a CCA.

The legal review will verify that the legal assumptions that underlie the business plan are correct. Most significantly, legal counsel will ensure that the plan allows the CCA to finance its capital projects with tax-exempt bonds and that the City's General Fund will be insulated from any liabilities. If legal counsel determines that a business plan cannot satisfy these legal prerequisites, the project will be halted and Council will be consulted. The Council may wish to

ask other jurisdictions to contribute towards the cost of this analysis. The Emeryville City Attorney has indicated that that City would likely contribute towards such an analysis and believes that such a threshold analysis would be prudent. The Oakland City Attorney's office has had little involvement on CCA so far but the City Attorney is seeking to coordinate with the Berkeley's City Attorney's office. The assumption that the CCA, which is a joint powers agency created under state law, can completely shield the cities creating it from liability for its activities also needs to be answered.

Even if the cities creating a CCA could legally protect themselves in whole or in part from the liability entailed in constructing and operating a power plant and supplying power to customers, as a practical matter, residents are still likely to look to the city councils of the member cities to protect themselves from rate increases perceived by such residents to be onerous. Thus, as a practical matter, cities undertaking such a venture should be prepared for customer expectations from their residents, especially in the event of any claims of mismanagement.

The City will also independently evaluate the market for CCA to determine whether there is sufficient interest to achieve the minimum market share necessary to make the project economically viable. Staff will work with independent consultants to conduct a series of focus groups or other market test tools to determine the interest and willingness to participate of various market segments. If there is insufficient market share (i.e., interest by potential participants) to support a CCA, the project will be halted and Council will be consulted. As a practical matter, even if the surveys indicate a sufficient interest, it will not be possible to know for certain how many resident are willing to actually commit to a CCA until after the expiration of an opt out period once a CCA has already been formed and the opt out period expires. Thus, at minimum, proceeding with a CCA will require the City to advance a considerable amount of money and make certain commitments to, for example to purchase power, before it will know whether there are a sufficient number of ratepayers who remain in the CCA after the opt out period to make the CCA economically viable. A financing plan developed in Phase II will determine whether these costs can be funded with bonds from the CCA and what liabilities the City would have to repay those bonds in the event that the CCA did not actually start and generate revenues.

A major portion of Phase II will be devoted to producing a final feasibility study based on a fully developed business plan. Navigant will conduct this work. The initial feasibility study determined that there is potential for a CCA based on market and other assumptions. The final study will refine this assessment based on specific plans and specific resources but some assumptions may have to be independently tested as described above. The feasibility study shall include obtaining qualifications and quotes from potential suppliers, identifying specific renewable generation projects for investment and developing revenue projections, collections procedures, a marketing plan, and a financing plan.

Navigant will also prepare governance and administration plans for the CCA that reflect the operating assumptions that it is testing in its feasibility study. These shall include the charter and by laws of the JPA, which govern its make up, responsibilities, authorities and operating rules.

The administrative plan shall include an operating plan that specifies the roles, responsibilities and initial schedule of activities for all major functions of the CCA. The plan will specify the nature of relationships and agreements with customers, suppliers, vendors, and PG&E. It will also include an initial staffing plan and specifications and qualifications for third party administrator(s).

Upon the completion of Phase II in late 2006 or early 2007, staff will deliver the final report and organize a Counsel workshop. Counsel will then be asked to make a decision to either create a CCA or terminate the project.

Major CCA Issues

Governance and Administration

The CCA would probably be governed by a JPA formed by the participating cities. The JPA would be the aggregator and would be responsible for operations of the CCA. City councils would be responsible for appointing representatives to the JPA. However, since the JPA would be a separate legal entity, many of its actions will not require the prior approval of any city council. The rights and obligations of the member cities in the JPA need to be evaluated by expert outside counsel to determine whether and how the cities can be shielded from liability for the actions of the JPA. They will also have to be spelled out in the joint powers agreement between the participating cities. Initially, day-to-day operations of the CCA (planning, purchasing, billing PG&E for customer revenues, customer service, administration, etc.) will be performed by one or more professional contractor(s) or energy companies that reports to the JPA and its staff. Over time, the JPA staff may replace the contract administrator. The cost of contract administration is included in the proforma. This means that the JPA will be heavily dependent on outside consultants.

Financing Investments in Generating Plant

Since there are significant economies of scale associated with plant construction, it is envisioned that the CCA would own a share of the electricity generating plant that would be constructed by several public entities, including other CCAs and existing publicly owned utilities, such as the Sacramento Municipal Utility District. Each entity would own a proportional share of the plant, would be entitled to that share of its output and would be responsible for that share of its expenses. Operations of the plant would likely be contracted out to professionals.

The financing should be structured such that the CCA ratepayers, not the JPA or the City itself, would secure the debt and the city would have no residual liability. Bonds are to be repaid by revenues from ratepayers of the CCA.

A bond counsel (not one retained by the City) has orally advised the staff from some cities that the aggregator would be able to secure tax exempt financing if appropriate protections for investors were adopted by the CCA. He said that the investors would require the Aggregator to have in place a mechanism to ensure that the customers departing the CCA after the initial opt out period would be assessed charges that would be used to pay for the debt service on any stranded investments left behind by the departing customer.

A stranded investment would be a portion of a generating plant or power purchase contract that was no longer needed by the CCA since the customer left and the value of which is lower than market rates. If a customer leaves the CCA, the excess capacity could be sold on the market. If the cost of that power (including the debt service) were higher than the market price, the departing customer would be responsible for the difference.

This would mean that if dissatisfied ratepayers went back to PG&E they would pay a price for having been part of the CCA. In order to avoid burdening ratepayers, it is therefore critical that the Aggregator's investments in generating plant are competitive and that the Aggregator minimizes customers returning to PG&E after such investments are committed. The CCA's ability to collect this fee and market acceptance will be assessed in early in development of the business plan but cannot be predicted with certainty because the economic changes in the marketplace and regulatory, bond and other constraints could require the imposition of such charges on departing customers.

Once the Aggregator's renewable generating plants come on line, rates should decline and stabilize, relative to PG&E's rates. There is of course attendant risk in the city going into the power generation business where it has no experience. While rate stability is possible through ownership and by reducing dependence upon fossil fuels in favor of renewables, there is additional risk in taking on the additional venture of power generation. Renewable plants have high capital costs but very low operating expenses, making them more stable. Unless required to increase its use of renewables by the State or voluntarily doing so itself, PG&E's portfolio is expected to have a larger percentage of fossil-fueled plants whose production costs will vary with fuel prices. In the near term (through 2012) however, the Aggregator may be required to purchase all its power on the market and at least half of its power on the open market thereafter. The Aggregator would likely execute a series of power purchase contracts with various terms that would provide some level of rate stability. The CCA will be exposed to prevailing market rates as each contract expires. It may be possible for the Aggregator to buy power from existing renewable energy projects developed by other public agencies prior to the timelines assumed in the feasibility study update. For example, the Southern California Public Power Agency is in the process of soliciting offers for developing renewable resources for the benefit of its members. Once a potential CCA program is developed to a level where it is viewed as a credible effort, the CCA may be able to buy into such existing efforts.

Risks

There are significant risks in pursuing a CCA. First and foremost, no public entity in California has ever formed a CCA since the law enabling local governments to do so was passed in 2002. Thus, not only will Berkeley, through the JPA, have to learn how to be a utility dealing with contracts in the tens of millions of dollars, it will not have the benefit of learning from the experiences of any other California cities.

While some of these risks may diminish with time, experience, and regulatory decisions, others, known and unknown, will exist throughout the development and operations of a CCA. These are

general risks associated with the electric power business and must be managed and accepted if the City decides to form a CCA.

In general, these risks are of two types: those borne by the CCA and its ratepayers and those borne directly by the City.

City's Risks

Unless outside investors are willing to financing the start up operations, the City will have to advance considerable funds that cannot be recouped if the CCA does not commence operations. The key assumption that a CCA will result in middle and long-term stability and perhaps lowering of rates require the CCA to generate power. Yet the CCA's members do not themselves have the entrepreneurial savvy and expertise to construct renewable power plants with the attendant regulatory and financial burdens of such a huge public investment. The CCA would have to focus it energies on both generating and selling power and distributing it and rate setting to the ratepayer.

The extent to which the City and its taxpayers can be insulated from financial liability for the activities of the CCA, while assumed by the consultant, is unclear and has not been explored. The extent to which tax exempt bonds can finance all or part of the operations of the CCA have also been assumed by the consultant but have not been spelled out or analyzed in any detail. Nor have these assumptions been the subject of any written bond counsel opinion opining on exactly what type of bond financing may permissibly be used for what operations and what fiscal constraints any such financing would impose on the CCA and current and departing ratepayers.

Even if the City could legally insulate itself from risk for the actions of a CCA it created, the ratepayer-customers of such an entity are nonetheless City residents who will likely look to the City Council to shield them from rates they find onerous, whether or not those rates are necessitated by the economic realities of power generation. The hard economic realities which dictate that exit fees may have to be imposed on exiting customers might be squarely at odds with the demands of ratepayers residents who become who perceive that they are being penalized for choosing the cheapest utility rates. These residents may well demand that the General Fund of the City to bail out the CCA so it can provide rate relief.

Assuming that investment grade revenue bonds may be issued to finance the physical power generation plant and that the General Fund can be insulated from claims, it should be noted that the General Fund could still be indirectly affected by default in two ways. First, the bond market could take into account a CCA default and downgrade the City's credit rating at the time of our next issuance of General Obligation bonds. Second, if the City Council failed to carry out its responsibilities, such as approving rates necessary to meet the revenue requirements, the bondholders might be able to sue the City for breach of contract and failure to exercise our full duties and responsibilities to the bond holders.

Furthermore, a poor CCA performance could affect the City in the form of higher rates for municipal facilities and lower tax revenues if the local economy is damaged.

CCA also presents political risks.

- The benefits of CCA are long-term, once generating plants are built and running. The risks, however, are immediate.
- Currently, the CPUC assumes responsibility for rates and consumer protection. Under a CCA, the City and its JPA representatives would assume some of these responsibilities. Council would be required to ratify rate increases specified by the JPA.
- There may be demands on the City to meet important social and environmental goals in ways that conflict with sound management practices.
- The City could cede most of its CCA governance authorities to a joint powers authority (a Berkeley-only CCA is less viable). Although the City now has no authority over electricity (it is currently the CPUC's and PG&E's responsibility), by creating a CCA it would assume responsibility and then delegate much of its authority to the joint powers authority but its residents might still expect the Council to take action to protect them as noted above.

Ratepayer Risks

When considering ratepayer risks, it should be noted that, as customers of PG&E, ratepayers are already exposed to many risks, stockholders assume others. In many respects, a CCA would represent a transfer of the responsibility of managing those risks from the CPUC and PG&E to local officials. Nevertheless, the nature of the risks for PG&E and CCA may differ.

There have been numerous financial disasters in the electricity market in recent years, including the bankruptcies of PG&E, Enron, and Calpine. These failures are due to a combination of factors including poor regulatory policies (PG&E), excessive risk taking (Enron and Calpine), and lack of supply diversity (Calpine). These examples illustrate that the electricity industry can be risky. Although a CCA is not immune from such causes, a conservatively managed CCA can have less risk exposure than the companies cited above. As a public agency, the CCA will be subject to minimal State involvement in its internal affairs, unlike PG&E and the impacts that State-mandated deregulation has on its business. Also, as a public agency, it will not be prone to risky behavior in order to maximize short-term stockholder returns, unlike Enron. And, as a CCA, it would also have a relatively stable demand from its customers, unlike Calpine, that would amortize its investments in supply.

Nevertheless, the energy business is unpredictable and extremely complicated and CCA ratepayers will inevitably be exposed to risks. Some of the major risks are presented below.

- Administrative qualifications, level of control and accountability: Embarking on a venture like power generation and supply involves trading in a volatile and commodity in a highly regulated and changing regulatory environment which the City has no experience, expertise or judgment and where it is dependent on an investor-owned utility to supply the power over its lines and the utility is entitled to compensated for the attendant costs and potential adverse impacts on its rates. The City's recent experience in

complying with conventional highly regulated programs has been spotty. This is especially true when the resources available to do so are limited as may be the case with a CCA that must be mindful of the bottom line because of the effects of runaway costs on rates and its customer base. Cities embarking into an entirely new entrepreneurial venture of building new power plants, generating their own power will have to rely entirely on contracting with staff and consultants who have not previously administered a CCA. The performance of contract administrators can be fully assessed only after operations have commenced.

- Power purchase contract costs: The CCA will be subject to price volatility, including natural gas price volatility for its power purchase contracts (initially 100% and later 50% of the energy will be from power purchase contracts) if not appropriately hedged. The business plan will obtain initial price quotes from providers but firm prices will only be available in the pre-operations phase when the CCA issues a binding solicitation; and the CCA will continue to be subject to price uncertainty in the market as initial power purchase contracts expire. As the CCA builds plant, the significance of this risk will decline.
- Natural gas price risk: The price of natural gas is a critical variable for CCAs. The revised pro forma assumes that gas prices are over 30% higher during the critical first few years of operations. This accounts for a significant portion of the difference between the original and revised proformas.
- Power purchase contract defaults: If a power supply vendor is unable to supply the power contracted for by the CCA, the CCA will be required to purchase power on the market at prevailing rates. If such a default occurs, it would be likely to happen during periods of short supply and high prices. The CCA may hedge this risk, at a cost, by requiring vendors to post bonds and/or investing in financial hedge instruments.
- Fees to exit the PG&E system: Upon start-up, the CCA will be subject to fees for exiting the PG&E system. The methodology for determining these costs is known (pending a final regulatory decision) and predicted values that were used in the feasibility study are fairly solid. Nevertheless, volatile market conditions could have some impact on the CCA in the first several years of operations.
- Subsidy shifts and the PG&E general rate case: Part of the benefits to Berkeley accrue from the fact that PG&E's small and medium commercial customers are currently subsidizing their residential and large commercial and industrial customers throughout the system. PG&E has recently revised its rates to partially correct this imbalance, reducing the benefits projected in the original pro forma. The revised pro forma accounts for this change. It is possible that PG&E will continue to correct rates, reducing the CCA benefits in later years.

- Residential tier subsidies: In a manner similar to the subsidies noted above, large residential users subsidize small residential users. In this case the existing subsidy favors Berkeley ratepayers, who are predominantly small residential customers. The effect of this subsidy was accounted for in the revised pro forma. No further risks from this topic are expected.
- Load forecasting: The CCA faces risks associated with load forecasting. The CCA could end up with too much power or too little, and may be exposed to adverse market conditions. This is an ongoing risk. Another forecasting risk appears to be being resolved favorably. A regulatory decision now pending before the California Public Utilities Commission will significantly reduce the risk the CCA would face due to incorrect load forecasts. Prior to this draft decision, the City might have had to pay significant penalties to PG&E if it failed to forecast properly.
- Administrative and staffing costs: Staffing and contract administration costs may vary somewhat from the estimates in the feasibility study based on the level of staffing, oversight and customer service that the City deems appropriate as the business plan is developed. A single City FTE is assumed to staff the City's representation to the JPA and to monitor the CCA's performance. The JPA's internal staffing and contract administration budget is assumed to be 5% of program revenues. A complete staffing and contract administration plan will be developed in the business plan.
- Credit and collections: PG&E and the CCA will share risks for bad customer debt. The CCA may return such customers to PG&E but will suffer proportional losses until the transfer takes place. The losses will need to be absorbed by the remaining ratepayers.
- Bondholder requirements: In order to secure affordable financing, the CCA will be subject to certain contractual terms or covenants specified by the credit agencies and underwriters. For example, the CCA and the City, as a party to the JPA, will be required to set rates that are sufficient to cover the debt service, operating costs, and operating reserve. Failure of the JPA and City to do so could result in a breach of contract and lawsuit. The credit agencies and underwriters will also stipulate other items, such as credit and collections processes, that may limit the authorities of the CCA.
- Tax Law Changes: CCA is dependent upon tax-exempt financing. Changes in the tax code that occurred before bonds are issued could undermine the economic foundation of a CCA.
- Regulatory Changes: If PG&E shifted costs from generation to transmission and distribution, that would increase PG&E charges to CCA customers. PG&E could also revise its tariffs on other CCA charges. Such changes would require the approval of the CPUC.

- Customer attrition and fees to exit the CCA system: A normal amount of customer attrition should not affect the CCA. However, if the CCA were to lose customers on a large scale after it invested in power generation facilities, the consequences could be significant. The worst-case scenario is that fixed costs would be levied on an increasingly smaller rate base, accelerating attrition and spiraling the situation out of control. In order to prevent such a scenario, the credit agencies and underwriters will make certain demands of the CCA and its customers. Specifically, they will require that the CCA impose exit fees on departing customers if the CCA is unable to service the debt through market sales of the excess generating capacity. The exit fee would vary depending upon the volume of attrition, the amount of excess capacity, and the prevailing market rates for power. The exit fee could remain a liability for departing customers until the debt was fully paid off (i.e., the life of the bonds), similar to the fees that now exist for the California Department of Water Resources energy bonds that were used to get PG&E ratepayers through the deregulation crisis.

The exit fees raise two significant concerns. First, the City must be able to collect the fees, either through PG&E (with their consent or with a new regulation from the CPUC) or through some other mechanism (such as a special tax). The specific mechanisms have not been identified. If no collections mechanism is available, the CCA will not be able to issue debt and will be infeasible. This issue will be resolved in the business plan.

Second, CCA ratepayers will be liable for the debt and if there are problems with the investments, they will bear the burden of the problems. This is somewhat similar to ratepayers' obligations under regulated utilities except that with investor owned utilities, ratepayers share the burden with stockholders. The amount of the exit fee would vary from zero, if there was a good market for the excess capacity, to the full amount of the debt services in the unlikely event that the excess power could not be sold on the market and all ratepayers departed the system. The business plan will include sensitivities in the pro forma that will quantify the exit fees under various conditions.

- Timing: Delays in generating plan construction would delay the economic benefits associated with tax exempt financing. The original pro forma assumed a very aggressive schedule for constructing or investing in physical power plants so that the CCA could quickly take advantage of tax-exempt financing. This schedule has been significantly slowed down in the revised pro forma.
- Cost, availability and performance of new renewable generating plant: The feasibility study's assumptions on the cost, availability, and performance of new power generating plants appear reasonable to the independent third parties, but the actual costs could vary based on market conditions, local purchasing policies, cost overruns, and operating conditions. It is assumed that 50% of the CCA's power will come from generating plants owned and operated by the CCA; therefore the impact of this variable is very substantial. Costs will be refined with each phase of the project, but certainty will only be available once the projects are commissioned.

Benefits

A CCA may offer the community rates that are stable and competitive with PG&E stability (through ownership of low-operating cost renewable generation as previously discussed), modestly lower rates and greenhouse gas reductions. Medium and long-term rates will likely be more stable and possibly slightly lower than PG&E rates based on the City's lower cost of capital, assuming the JPA invests in power generation facilities. The CCA will have a large share (50%) of its electricity requirements derived from renewable plants owned by the Aggregator. Renewable plants have low operating expenses and ownership insures that the plants will be dedicated to the CCA.

In terms of greenhouse gas reductions, assuming that there is no change to State policy and PG&E is required to acquire 20% of its electricity from renewable sources by 2017, it is estimated that Berkeley's participation in a CCA will result in the reduction of 114,000 tons of CO2 emissions annually. This represents over 50% of the City's stated policy objective of reducing all community emissions by 15%. If the State accelerates the renewable requirements to 33% by 2020, the CO2 emissions reduction attributable to Berkeley's participation in a CCA will be somewhat lower; however, CCA rates relative to PG&E will be lower as well. PG&E's cost to acquire renewable resources will be higher than the CCA's since they will be relying on projects financed with taxable debt.

POSSIBLE FUTURE ACTION

The Council could take the actions described below.

- 1) Council could take no further action at this time and wait to watch the experience of other cities and CCAs before it determines whether to go forward. While it would lose the benefit of using grant funds to engage in further studies of the feasibility of CCA, such a study would have no actual experience of other CCAs to study and ratepayers may be more reluctant to participate without more evidence of a track record. The grant funds currently available may not be available at a later time.
- 2) Council could postpone the award of the Phase II study to Navigant pending further community discussion and investigation of the risks and benefits of proceeding further, which might include the commissioning of a legal opinion as to risks and legal pitfalls attendant in creating a CCA via a JPA to generate power. Under this course of action, if the City does decide to award the contract to Navigant at a later date, many of the key variables in the business plan may already be established by the other partners and Navigant. As a partner, the City would be responsible for paying for these elements of the business plan but may not be adequately represented as they are developed.
- 3) Council could award the Phase II contract with Navigant, simultaneously obtain legal advice and do market surveys of possible ratepayers and preserve the option to halt the Navigant work if the legal and market studies indicate that CCA is impractical. The

City's financial risk in under this action is limited to the expense of funds for the study. Phase II does not commit the City or ratepayers to any other liabilities.

FISCAL IMPACTS OF POSSIBLE FUTURE ACTION

Refer to the Council Action report.

CONTACT PERSON

Neal De Snoo, Energy Officer, Housing Department, 981.5434

Attachments:

- 1: Attachment 1: Review of Navigant Consulting's Community Choice Aggregation Feasibility Studies
- 2: Updated Proforma



MEMORANDUM

To: Tim Rosenfeld, Consultant to Marin County

Cc: Neal DeSnoo, City of Berkeley
Karen Hemphill, City of Emeryville
Gwen Johnson, Marin County
Carol Misseldine, City of Oakland
Pat Stoner, Local Government Commission

From: Bill Monsen and Mark Fulmer, MRW & Associates, Inc.
Bill Marcus, JBS Energy

Subject: Review of Navigant Consulting's Community Choice Aggregation Feasibility Studies

Date: August 17, 2005

As requested, MRW & Associates, Inc. (MRW) and JBS Energy (JBS) have reviewed the studies "Community Choice Aggregation: Base Case Feasibility Evaluation," (Studies) performed by Navigant Consulting, Incorporated (NCI) for the City of Berkeley (Berkeley), City of Emeryville (Emeryville), the City of Oakland (Oakland), and Marin County (Marin). As can be expected from the Phase 1 feasibility study design, where detailed work was not expected to be undertaken on individual communities' load patterns, these studies are nearly identical, differing only in the reported inputs, results tables and minor wording changes; the underlying analysis methods, qualitative analysis and conclusions are the same. As a result, we have provided very few comments related to reports for individual jurisdictions; nearly all of our comments are generic.

This memorandum is organized as follows. First, we describe our approach to this assignment. Next, we summarize our conclusions regarding the forecasts of natural gas and power prices assumed in the Studies. Next, we discuss the Studies assumptions regarding PG&E's other generation-related costs. After that, we discuss significant risks related to possible future changes in PG&E's rate design that could affect the economic viability of a CCA. Finally, we critique some of the risk assessment provided in the Studies.

Approach

For this project, MRW and JBS reviewed the Studies to understand NCI's approach for evaluation of the feasibility of CCA. In addition, JBS met with NCI to evaluate the modeling approach used by NCI for the Studies. MRW and JBS also spoke with NCI to understand some of NCI's assumptions and analysis decisions.

In general, MRW and JBS found that the overall approach used by NCI for the Studies to be reasonable, given the amount of uncertainty that exists in the key factors that drive the economic viability of CCAs. NCI examined a number of different scenarios in its Studies, in an effort to evaluate the impact of uncertainty in key drivers to the feasibility of CCA.

As discussed in greater detail below, MRW and JBS have certain reservations regarding the assumptions used in the Studies. However, when NCI performs Phase 2 analyses of CCA for the cities and county, then we would expect that NCI would make changes to its input assumptions as needed.

Market Price Forecasts

MRW reviewed the underlying price forecasts for natural gas and wholesale electricity presented in the Studies. Our conclusions are as follows:

Market Gas Price Forecasts

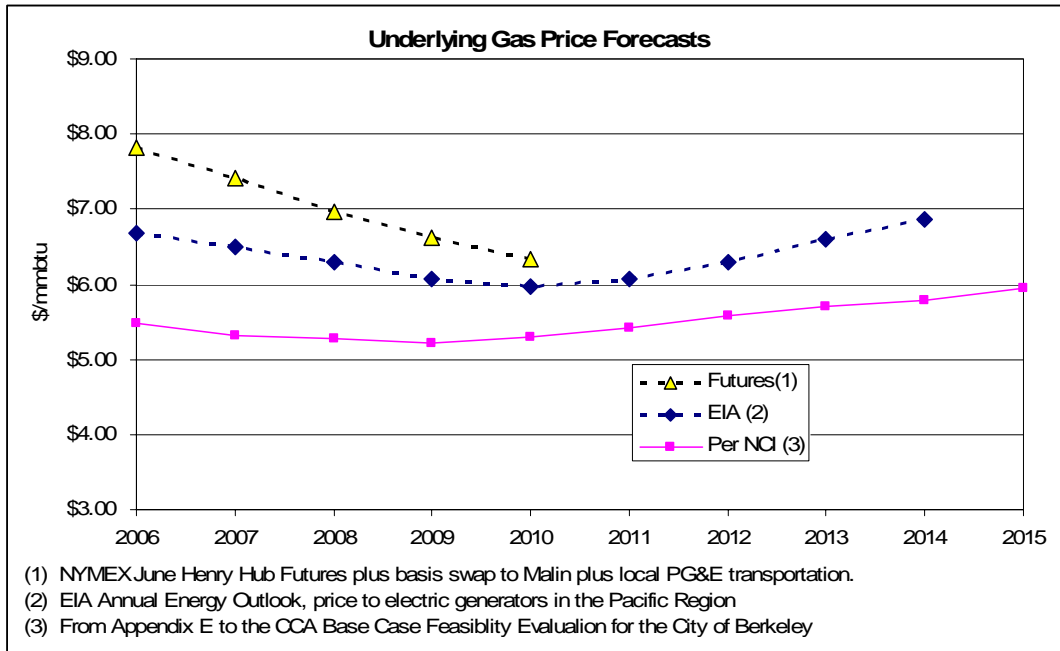
Gas prices have been highly volatile over the past several years. As a result, it is expected that any point/line forecast of gas prices is likely to be incorrect in the future. Given the changes in natural gas prices over the past six months, it is not surprising that the view of the gas markets today is different than the view developed several months ago when NCI conducted its analyses. That being said, MRW's conclusions regarding the gas price forecast presented in the Studies are:

- The gas price forecast is low compared to EIA's 2005 *Annual Energy Outlook* (gas to electric generators in the Pacific Region).¹
- The gas price forecast is very low (-\$2.00/mmbtu, 30%) compared to current futures in the near term, with the gap narrowing to ~\$0.50/mmbtu by 2011.²

The following figure compares the NCI gas price forecast against these two publicly-available sources for natural gas pricing.

¹ Supplemental Table 19. Adjusted to nominal dollars using a 2.2% annual inflation rate.

² Average Futures price quoted in *Gas Daily* during the month of June 2005. Henry Hub prices adjusted to Malin using *Gas Daily*'s basis swap price with local and backbone PG&E gas transmission rates added in to achieve the burner tip price shown in the figure.



Conclusion: Given more recent information and events, the NCI base gas price forecast in the Studies appears now to be too low, particularly in the near term. The “high” case (not shown in the figure), in which gas prices are increased 25% over the base forecast is more consistent with the other forecasts in the near term but somewhat high in the long term.

Recommendation: This item should be reviewed and updated in any future feasibility studies. In addition, future feasibility assessments should evaluate the impact of volatile gas prices on financial performance of the CCA by examining a wide range of future gas price scenarios.³ This would provide a better assessment of the potential upside and downside risks associated with particular resource procurement strategies.

Market Power Prices

California’s marginal supply of power is primarily fired by natural gas. As a result, wholesale market prices for power in California are heavily influenced by natural gas prices. Thus, volatile natural gas prices cause wholesale power prices to be volatile. Consistent with our comments above regarding natural gas prices, we are not surprised that the market price forecasts for electricity in the Studies are inconsistent with current market indicators. MRW’s conclusions regarding the NCI forecasts for wholesale electricity prices are:

- Projected on-peak power prices are much lower than current forward prices in the near term (2006, 2007): ~\$53/MWh (NCI) versus \$77/MWh (NP 15, quoted in

³ For example, one scenario that might be useful to evaluate is where gas prices are higher than expected in the near-term and lower than expected in the long-term. Such a “perfect storm” scenario would help the CCA understand the potential downside of pursuing CCA.

MW Daily). Even if one factors in the 5% premium that NCI assumes for long term contracts (so as to get closer to an apples-to-apples comparison), NCI's \$53 increases to only \$56.⁴

- Market heat rate: The NCI Studies assume 8,000 Btu/kWh in 2005 ramping up to 11,000 Btu/kWh in 2010 (and thereafter). Current NP15 to Malin heat rates (based on 2006 and 2007 forwards) is about 9,200 Btu/kWh.

Conclusion: The market prices for power are significantly too low in near term; this may be better after 2010, when the higher market heat rate counteracts the low gas price forecast. However, long-run market heat rate seems quite high, especially given expectations for relative improvement of generating fleet efficiency over time.

Impact: The understatement of wholesale power prices is possibly significant, especially in the near-term, when the CCA would be more dependent on market-based power supplies rather than its own generation. Given the projected resource mix, in 2006-2008 a \$20/MWh underestimate of contract and spot power prices would mean an additional 20% total estimated CCA cost in those years.

This impact is mitigated to a certain extent by the higher market power prices flowing through PG&E rates, since higher market prices for power result in higher PG&E generation rates. However, MRW's independent modeling of rates has found that PG&E's generation rates are not as sensitive to gas and power prices as the NCI model appears to be.

Recommendation: This item should be reviewed and updated in any future feasibility studies and in Phase 2. In addition, future feasibility assessments should evaluate the impact of financial models on a wide range of future power price scenarios. This would provide a better assessment of the potential upside and downside risks associated with particular resource procurement strategies. It would also allow the CCA to understand the potential magnitude of any reserve accounts it might need to establish, should rate stability be a primary driver behind formation of the CCA.

Resource Cost Assumptions

The Studies assume the following CCA power supply resources:

⁴ MRW does not have access to publicly-available forward market price data after 2007.

	Berkeley	Emeryville	Oakland	Marin
Wind in 2008 in 2013	30 MW 40 MW	10 MW 25 MW	120 MW 20 MW	90 MW 80 MW
Geothermal in 2008 in 2013	5 MW 5 MW	3 MW	120 MW 20 MW	10 MW 20 MW
Natural Gas-fired Combined Cycle in 2010	20 MW	10 MW	50 MW	50 MW

NCI has used somewhat conservative estimates for its new resource costs, which is reasonable and appropriate. For example:

- NCI's cost assumptions for its NGCC are: \$700/kW construction costs, 7,000 Btu/kWh heat rate, \$3/MWh average O&M, and a 90% capacity factor. These assumptions are generally consistent with the CEC's "Comparative Cost of California Central Station Electricity Generation Technologies" August 2003. While the NCI installed cost estimate is higher than the CEC's assumption,⁵ recently installed projects (such as Palomar) have also been more expensive.
- Based on the "CCA Generation Resources in CCA Portfolio" tables found in each of the Studies, NCI's implied installed cost for new wind generation is \$1,100/kW in 2008. This is also somewhat high relative to CEC estimates.⁶
- Implicit installed cost for new geothermal facilities is \$2,760/kW in 2008. This installed cost estimate is high relative to CEC.⁷

Conclusions: NCI used generally conservative assumptions for its new resources.

Recommendations: Future feasibility studies should continue to use conservative assumptions regarding new resource costs. In addition, the sensitivity of financial results should be tested relative to cost overruns associated with new generation facilities. For example, anecdotal evidence indicates that current wind power projects are approximately 30 percent more expensive than projects developed two years ago because of increases in steel, concrete, and turbine costs. Such cost increases could have a significant effect on a CCA's economic viability.

⁵ California Energy Commission, "Comparative Cost of California Central Station Electricity Generation Technologies" August 2003, Appendix D.

⁶ California Energy Commission, "Renewable Resources Development Report," November 2003. Appendix D.

⁷ Ibid.

Resource Procurement Assumptions

Aside from the underlying costs of new resources, the Studies made assumptions regarding the availability of new resources. Our concerns with the Studies' assumptions in this area include:

- To meet the goal of having new generating resources online by 2008, it is likely that the CCA would need to buy projects that others have already begun the development process, since greenfield, or even brownfield, resource development by 2008 is highly unlikely.
- It is unclear how the CCA would procure new geothermal power.⁸ There are not many locations for new geothermal development. The CEC's Renewable Resources Development Report shows potential resources in Modoc, Siskiyou Mono and Imperial Counties. The cities and Marin would likely have to utilize resources in Modoc or Siskiyou Counties, as purchasing geothermal power from projects in Imperial and Mono counties would likely present transmission issues/congestion risks. On the other hand, siting new geothermal plants in these northern counties may present environmental and cultural impact issues that the cities and Marin may not find acceptable (e.g., Calpine's experience in development of projects in the Glass Mountain Known Geothermal Resource Area in Modoc Country).
- The Studies assume that the CCAs would be able to acquire 10-50 MW of a new natural-gas fired combined cycle. This assumes that there is a joint development effort, similar to that for the Magnolia generating station by the Southern California Public Power Authority. Such joint development efforts can be complicated and time-intensive and makes the 2010 on line date optimistic.
- In the long run, it was assumed that the CCA would acquire power to back up wind power and meet resource adequacy requirements at \$100/kW-year. It is possible that the construction of a CCA-owned combustion turbine (and its operation when cost-effective relative to market prices) could be cost-effective relative to purchasing this power. However, such a resource could not be acquired quickly, and may only be cost-effective for a group of CCAs or a very large entity such as the City of Oakland acting alone.

Conclusions: The resource procurement assumptions in the Studies may be optimistic, especially the short development times assumed. Development of a combustion turbine after 2010 should also be considered further as a means of lowering costs and market risks.

Impacts: The risk of delay in development would require the CCA to purchase market-based power for a longer period than anticipated. It is not clear that the CCA would be able to procure power at prices significantly better than market, which means that the

⁸ By referring to the Renewable Resources Development Report, we assume that NCI assuming new geothermal resources, rather than buying into an existing project. If the latter is the case, a discussion of this assumption is warranted.

CCA's profitability would be challenged for a longer period after startup. Later in its timeline, CCA costs may be reduced if it can develop its own peaking generation.

Recommendations: Future feasibility studies should evaluate the impact of delays in new generation resource additions. This would provide the CCA with a greater understanding of the risk to near-term profitability associated with delay in new resources coming online.

PG&E Generation Cost Forecast

NCI has prepared a forecast of PG&E generation costs by component. Overall, the methodology used by NCI appears reasonable, though we have corrected some assumptions that reduce PG&E's costs by about 0.6%. While such a differential appears small, it is large enough compared to the projected margins of the CCAs to be noted. In addition, the assumptions are largely independent of the gas/market price issues and are instead likely to reduce margins somewhat in all cases.

We have also identified two large uncertainties (that are largely offsetting through 2024) relating to license extension for Diablo Canyon and potential reductions in PG&E hydro generation due to future environmental restrictions. These uncertainties, which are not under the control of the CCAs and cannot reasonably be hedged by them, must be monitored carefully. In particular, a scenario with nuclear license extension and little hydro generation reduction could be adverse in the out years of the study.

The costs of utility owned generation (largely hydro and nuclear) is estimated based on 2003 O&M costs escalated with inflation, and 2003 capital costs constant in real dollars⁹ and depreciation rates remaining constant as a percentage of capital investment.

Revised Assumptions

The corrected assumptions that we have identified are as follows:

1. There is an erroneous cell reference in the rate base calculation for hydro. The effect is a \$21 million NPV decrease in hydro costs, with hydro costs slightly higher in the near term and falling in the out years.
2. Capital investments for hydro may be understated in the out-years after 2010, as costs were cut in half starting in 2011 with no explanation. In addition, the figures developed by NCI appear to exclude relicensing costs, which are not placed in current rates until the new license is granted but will be included at rates at that time. PG&E's costs could increase by as much as \$293 million net present value (at least \$40 million per year in each year after 2014) if capital investments remained constant after 2011. We also note that there will continue to be relicensings in this later time frame.

⁹ Except declining 50% for hydro in 2010 and the steam generator at Diablo Canyon.

3. Depreciation expense for Diablo Canyon is understated, as it does not take into account the shortening of the remaining life as the license expiration date approaches, and net plant is overstated because no depreciation is taken from the beginning of the year to mid-year. The overall net impact of the two offsetting changes is small (about \$32 million net present value), but costs fluctuate significantly after 2015.
4. NCI's forecast of future capital spending at Diablo Canyon is considerably higher than PG&E's most recent forecast after 2012.¹⁰ Applying PG&E's lower forecast reduces PG&E's costs by \$220 million (present value) or \$671 million (sum) relative to NCI's forecast.
5. The forecast of QF purchases is overstated after 2013 and even more overstated after 2020 because NCI fails to consider contract expirations that will be renewed at lower prices or replaced with market-priced energy. The cost of QFs is approximately \$10/MWh over the cost of new bilateral contracts in the 2015-2024 time frame. Factoring in a more rapid decline of QF power and replacing that power with bilateral contracts reduces PG&E's costs by a sum of \$909 million (net present value of \$357 million) after 2010. A better analysis of QF contract expiration is recommended for Phase 2; we simply assumed for this review that all contracts expired in year 30.

The net impact of these five items is to decrease PG&E's generation costs by 0.6%, with larger decreases in the 2% range after 2020.

Other Uncertainties to Be Noted

6. The impact of a potential license extension at Diablo Canyon could reduce costs in the intermediate term through lower depreciation rates (partially offset with a higher rate base). After the end of the study period in 2024, if relicensing were feasible, PG&E would substitute cheaper Diablo Canyon energy for more expensive market priced energy. Prior to 2024, a 15-year license extension identified in 2011 could reduce costs by amounts starting in the \$100 million range in 2012, declining over time as the rate base increases and crossing over to provide slightly higher costs in 2018-2022. Costs in 2023-2024 would also be lower because end-effects of the Diablo Canyon shutdown would be postponed for 15 years. The net present value of the change would be \$242 million NPV in lower costs (assuming PG&E's lower capital forecast) and the sum would be over \$450 million.¹¹ This is a fairly large uncertainty associated with the CCA that is entirely within PG&E's future control.

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¹⁰ CPUC App. 04-01-009. Diablo Canyon Steam Generator Replacement, PG&E response to TURN Data Request 3-8.

¹¹ This effect of lower costs through 2017 and higher costs afterward would result because depreciation expenses would be lower due to the license extension. The depreciation reserve would also be lower, thereby causing rate base to increase, increasing PG&E's required return and taxes.

7. NCI uses a constant forecast of PG&E hydro energy, which is reasonably - conservative for a base case, as it can be expected that average energy production will actually decline slowly as new environmental restrictions are imposed when projects are relicensed. A decline of a billion kWh in annual average production over the next 20 years and replacement of this virtually no-cost energy with bilateral contracts would increase PG&E's costs by \$840 million (sum) or \$376 million (net present value), raising costs by about 1%.

Results

The table in Attachment A summarizes the adjustments discussed above to NCI's projection of PG&E's generation costs. While all of these changes appear large, the impact of the corrections on PG&E's overall costs (without a nuclear license extension or reduced hydro generation) changes costs by less than ½ percent through 2018 and reduces them by about 1.5 to 2% from 2018-2024 due to QF contract expirations and Diablo Canyon depreciation changes. With nuclear license extension, PG&E's costs are 1% to 1.2% cheaper from 2012-2018 and 1.4 to 1.9% cheaper from 2019-2024. This difference (even though relatively small and overshadowed by other differences such as gas prices) is still important, because it is likely to represent up to 20% of expected base case savings in the period after 2012 and is independent of the "normal" sources of forecasting risk such as gas prices.

However, a possible reduction in PG&E's hydro production would wash out most of the change, leaving PG&E's overall costs 0.25% less than NCI's forecast over the entire time frame and 0.6 to 0.9% less than NCI's forecast during most of the period after 2012.

Other PG&E Cost Forecasting Issues

Volatility in PG&E's Generation Costs Around the Average Due to Hydro Conditions

PG&E's hydro generation was estimated by NCI using average year conditions. However, PG&E's hydro production fluctuates by more than 6 billion kWh from the average year to either the wettest or driest year of record, and the standard deviation is 3.4 billion kWh.¹² Simply due to hydro conditions, PG&E's costs can fluctuate by plus or minus 6.2% from the wettest or driest year of record to the average (assuming base case market prices and gas costs), and the fluctuation due to the standard deviation would be 3.6% of PG&E's base case cost estimate. Thus, in a wet year (or a year after a wet year when an ERRA rate reduction could be triggered), a CCA could easily end up with higher rates than PG&E's rates, even if, on average, its costs could be expected to be less. In other words, CCA customers may receive more stable rates as well as rates that are lower on an expected hydro basis than if served by PG&E, but their rates may not be cheaper in all years.

¹² Based on PG&E hydro generation data used to develop W. Marcus and R. Kinoshian, *Joint Testimony of the Office of Ratepayer Advocates and The Utility Reform Network and the California Farm Bureau Federation on Retention Alternative*, CPUC App. 99-09-053 (PG&E Hydro Valuation). June, 2000.

Estimate of CDWR Bond Charge

NCI forecast a flat rate for CDWR bonds. Actually, the rate is likely to decline over the life of the bonds as (1) some bonds are paid off; and (2) load growth increases the kWh sales associated with the bonds. However, this change has no effect on net margins for CCA because both PG&E's rates and its non-bypassable charges will decline by equal amounts in cents per kWh or dollars per year.

Estimate of Nonbypassable Charges (Cost Responsibility Surcharge or "CRS")

Some of the CRS elements are very stable and predictable while others are not. The predictable elements are the CDWR Bond Charge (discussed above) and the Regulatory Asset Charge. On the other hand, the DWR Power charge and CTC are variable and potentially volatile.

The DWR Power Charge is the only element of the CRS that is only paid in the CRS (i.e., it is not included in PG&E bundled rates as a specific element). CDWR issued a brief memo on June 2, 2005 which presented its estimates of the CCA CRS to R.03-10-003 (the CAA proceeding).¹³ It showed the DWR Power charge plus CTC to be \$13/MWh in 2006 and \$12/MWh in 2007, compared to the Studies, which show the sum of these elements to be \$7/MWh and \$6/MWh in those years. However, it should be noted that the costs of service for power in the DWR update memo was \$50 per MWh, while the cost of service in the Studies was \$56 per MWh. This points up the importance of internally consistent assumptions for determination of the DWR Power Charge, CTC, and cost of service. In addition, it is important for the reader to understand that if the sum of cost of service plus CRS were increased by \$5/MWh, then this would add, for example, \$2.6-\$3.6 million per year for 2006 through approximately 2010 for Berkeley. This magnitude of error in price and cost forecasting alone could eliminate the CCA savings in those years.

Startup Costs

In all four studies, NCI assumes that start-up costs are the same and capitalized through 2015 (ten years). While the amortization of the start-up costs may be reasonable, its amount, \$350,000 in Appendix B and \$400,428 in the pro forma in Appendix E, is likely understated for Oakland and Marin. Given the notification and mass-enrollment fees proposed by PG&E in Phase 2 of the CCA proceeding,¹⁴ Oakland would pay PG&E over \$400,000 in these fees alone, let alone city-incurred regulatory and legal costs. Because of its much smaller size, Emeryville would face approximately \$50,000 in PG&E notification and mass-enrollment fees, making the \$350,000-\$400,000 estimate for more reasonable.

Since these costs are to be amortized over ten years, plus or minus a few tens of thousands of dollars of startup costs will not materially affect the cost-effectiveness of

¹³ California Department of Water Resources "Projected 2006 and 2006 Cost Responsibility Surcharge for Community Choice Aggregation," June 2, 2005.

CCA formation. Nonetheless, the volume-specific costs and fees should be accounted for in a more rigorous analysis.

Metering and Billing Costs

Based on PG&E's proposal in Phase 2 of the CCA proceeding, the projected metering and billing costs presented in the pro forma in Appendix E slightly understates (5%-15%) the likely metering and billing fees the CCA would have to pay PG&E. San Francisco has aggressively challenged a number of those fees, and if it prevails, could reduce these costs by 50% or more.

Regulatory Risk: Impact of Changing Allocation of PG&E Costs to Customer Classes

NCI's base case starts with current rates and escalates rates to all customer classes at the same percentage. This method has the effect of locking in today's relatively lower residential rates and higher commercial/industrial rates for the next 20 years. The savings available to jurisdictions is dependent on their customer mix, with high savings in NCI's base case to jurisdictions with more commercial and industrial customers.

NCI's sensitivity Case E shows much lower savings from CCA for most jurisdictions based on PG&E's proposal to reallocate revenue to increase residential costs and lower commercial/industrial costs. Savings drop from the 10% range to 3% for Emeryville and 3% to 1% for Marin with the rate reallocation in Case E.

Ultimately, it is extremely likely that a change similar to NCI's Case E will take place, although it will be phased in over the next several years. Under the recent PG&E rate settlement, approximately one third of the change will be phased in by January 1, 2006. Additional changes will occur in later years. The largest residential increase and commercial/industrial decrease is likely to occur in 2008, when the rate reduction bond charges expire and some of the rate reduction that would otherwise occur for residential customers could be diverted to reduce cost disparities.

We therefore recommend a blended scenario which starts with the current allocation and reaches NCI's Case E by 2009.

Residential Class Rate Design Uncertainties: Tiered Rates and CARE Allocation

The NCI studies – as initial feasibility studies – are based on an average class rate for the residential class. In fact, under AB 1X, which requires no rate increases for use up to 130% of baseline, the residential class rates currently collect a large portion of the generation costs from use over 130% of baseline (Tiers 3, and 4, as well as Tier 5 which

¹⁴ The key volumetric start-up costs are four official opt-out notifications at 36¢/account/notification plus a PG&E-proposed mass enrollment notification of 40¢/account. Note that San Francisco has aggressively challenged this latter fee in the Phase 2 proceeding and that CCAs can provide the opt-out notifications themselves, although it is doubtful they could perform this task at a significant savings relative to PG&E.

will return under the new rate settlement). PG&E's current generation rates are as follows:

	Generation Component Rate E-1		Rate EL-1
	6/1/2005	1/1/2006 settlement	CARE
Baseline	\$0.03153	\$0.03153	\$0.03019
Tier 2 (100-130%)	\$0.02850	\$0.02850	\$0.02776
Tier 3 (130-200%)	\$0.07486	\$0.07604	\$0.02776
Tier 4 (200-300%)	\$0.11462	\$0.11997	\$0.02776
Tier 5 (> 300%)	\$0.11462	\$0.14008	\$0.02776

In other words, under PG&E's rates, use up to 130% of baseline pays about half of the class average generation cost, while Tier 3 pays about 20% more than the class average cost and Tier 4 pays about 85% more than the class average cost.

The intraclass residential rate tiering (with no increases on rates up to 130% of baseline) is required by AB-1X through 2011 (when DWR power contracts expire). As a result of the recent rate design settlement, a portion of the tier differential will be provided for all tiers in both generation and distribution, so that the impact of residential rate design will be mitigated but not eliminated relative to current regulation.

Despite this mitigation, the distribution of residential consumption within the five tiers in the cities subject to the CCA will still have a critical impact on project feasibility. The table in Attachment B shows the class average distribution by rate schedules, but individual communities could be significantly different from this average. About 62% of rate E-1 use (excluding medical baseline) is at baseline and 11% more in Tier 2, with only 27% in Tiers 3-5.

In addition, only about half of the CARE rate discount is contained in the public purpose program charge paid by all customers and the DWR bond charge exemption for CARE customers. The remainder is still contained in the bundled generation rate, which has the same rates in Tiers 3 through 5 as in Tiers 1 through 3.¹⁵

Finally, PG&E's FERA (Family Energy Rate Assistance) program, which provides discounted third-tier rates to families of three or more at income levels just above the CARE income eligibility requirement, is funded entirely through the bundled generation rate. While there are not many FERA customers, they could also cause erosion of the margin from community aggregation.

¹⁵ PG&E proposed to change the CARE discount structure in its current Phase 2 proceeding, but that change was deferred because of impacts on Direct Access Customers in the settlement of that case. The issue of whether the CARE discount will remain in the bundled generation rate may be decided in the CCA OIR, but a regulatory uncertainty will remain until that decision.

Because of the generation rate design for PG&E,¹⁶ there is a serious uncertainty in the economic impact of serving residential CCA customers that requires the granular and detailed analysis that is expected to be part of the Phase 2 studies. Jurisdictions with a higher percentage of CARE customers than the average or a higher percentage of residential use below 130% of baseline than the average may well have negative margins, while wealthier jurisdictions may be able to make more money from residential users. Previous JBS analysis (using PG&E's 1995 residential customer survey data) demonstrates that after taking climate zones into account, residential electricity use is related to dwelling size and type, household size, and income.¹⁷ Thus jurisdictions with higher incomes, which contribute to both higher use and fewer CARE customers, and a lower percentage of apartments (such as Marin County) may have residential loads that would give them a much larger margin than jurisdictions with lower incomes and/or with large numbers of apartments (e.g., Oakland and Berkeley). This is a critical point for detailed analysis by NCI in future studies using actual PG&E billing data for each community.

Load Profiling and Advanced Metering Issues

At present, the CCA providers must balance the loads of their non-load-profiled residential and small commercial classes based on system-wide load profiles. This practice prevents Bay Area CCAs, such as the ones in these Studies, from benefiting fully from their load profiles that are less peaked than the system as a whole.¹⁸ Essentially, CCA providers receive the benefit of any difference in monthly loads (i.e., if July is a lower fraction of their annual loads than for the system as a whole), but within the month must settle their power deliveries based on the class average profile.

This has two ramifications:

1. There is probably a modest benefit to Bay Area CCAs based on the fraction of load in peak versus non-peak months. This can be explored when area-specific billing data are made available.
2. There is a question as to how PG&E will conduct its load profiling once the CCAs are established. Will the profile be based on its service area or only those customers that it continues to serve with generation? The answer to this question is unknown at this time. If it is based on the customers that PG&E continues to serve and a larger number of Bay Area customers join CCAs, the profile may become more adverse than it is today.

¹⁶ The problem is made worse by the apparent fact that PG&E will only allow CCAs who use its billing system to have only two-tier rates.

¹⁷ See W. Marcus, G. Ruzsovan, and J. Nahigian *Economic and Demographic Factors Affecting California Residential Energy Use*, pp. 53-56. The document is available at: <http://www.jbsenergy.com/downloads/California%20Residential%20Energy%20Use%20Economic%20and%20Demographic%20Report.pdf>

¹⁸ Navigant was provided Bay Area specific load profiles which it used in Phase 1. However, there is still a single systemwide load profile for the few remaining DA residential customers.

In addition, PG&E's application to install advanced meters may have a number of impacts on CCAs that are presently uncertain.

1. Advanced meters could resolve load profiling issues to the benefit of CCAs. These advanced meters would collect data from individual small customers, so that actual use by CCA customers would be known. In essence, they might "break" the profile and allow the CCAs to balance based on actual deliveries to their customers. In such an event, advanced meters are likely to improve the position of Bay Area CCAs.
2. Advanced metering will also allow the development of "critical peak pricing" rates. For residential Bay Area customers, particularly in Oakland, Berkeley and Emeryville where air conditioners are virtually non-existent, advanced metering is probably not cost-effective to install. However PG&E is pushing for the meters, and the California Public Utilities Commission is likely to require their installation anyway. Once that decision is made, the cost of the metering is sunk. In that case, it is likely that most Bay Area customers served by PG&E would benefit from signing up for critical peak pricing because of their lack of air conditioning. This could potentially lower the PG&E rate against which CCAs are competing. In addition, it could give the CCAs their own opportunity to offer (and even promote) a similar rate – depending on how the billing relationship between PG&E and the CCA evolves – as well as the CCA's ability to avoid Resource Adequacy Requirements and use the spot market for power conserved by CPP on hot summer afternoons. But CPP rates under consideration at present by PG&E have critical peak prices much higher than the market cost of energy.

In sum, the impact of advanced metering on rate offerings is likely to be negative if the CCA cannot cost-effectively offer similar critical peak rates, and in such a case would offset some of the benefits of the ability of CCAs to use their own actual loads instead of a profile.

All of these issues must be considered further in Phase 2 and particularly when more is known in 6-12 months, after the CPUC makes a decision on AMI, and as CCA activities come closer to start-up.

Additional Risk Issues

In addition to the issues raised above, MRW has reviewed the discussion of risk issues identified in the Studies. The following discussion identifies several areas in which NCI should either expand the Phase 1 report or address the issue in its Phase 2 analyses:

- IOU opposition to CCA may not be extensive. MRW believes that any prospective CCA must be fully aware of the potential risks that the local IOU faces with respect to the future viability of its CCA. While NCI's report lists several ways in which the IOUs might oppose a CCA,¹⁹ MRW believes that the

¹⁹ Oakland Study, pp. 33-34.

Studies' assessment of these risks might be understated and, as a result, misinterpreted.²⁰ As a result, some additional explanation and discussion of this issue is warranted. While PG&E has been generally cooperative with San Francisco in its bid to form a CCA, some of the rules and fees it has presented in the CCA proceeding are not conducive to CCA formation. Other utilities have not been nearly as cooperative. SDG&E, for example, has actively opposed formation of CCA (as evidenced by its actions with respect to Chula Vista). SDG&E has attempted to establish rate structures that would make CCA less economic (e.g., additional non-bypassable charges to ensure that CCA customers pay subsidies to remaining residential customers). It is possible that similar efforts will occur in future PG&E rate proceedings. CCAs will need to keep an eye on these issues. To do so will result in the CCAs bearing ongoing regulatory costs, which are costs that most cities don't current bear.

- CCA Rules to be established in June 2005.²¹ This is not correct. The Administrative Law Judge has not yet issued a proposed decision. It is more than likely that this will be September 2005 at the earliest. Conclusion: The Phase 2 CCA ruling will establish many of the "rules of the road." How the decision falls could add or remove hundreds of thousands of dollars of costs to CCAs. Until this decision is issued, the operating costs for the CCA are highly uncertain.
- Risks can, to a great extent, be mitigated.²² The risk mitigation measures proposed in the Studies seem to be somewhat contradictory. For example, to mitigate CRS volatility risk, NCI recommends short-term purchases but to mitigate commodity price volatility, NCI recommends longer-term purchases or obligations. Both risks (i.e., CRS volatility risk and commodity price risk) cannot be mitigated simultaneously and CCAs will likely have to bear one or the other of these risks until the CRS risk disappears. In addition, it is unclear that suppliers will be willing to offer "guaranteed discount pricing structures." Suppliers were burned in the past when they offered such products and may be hesitant to provide such products again. This is especially true if the suppliers are asked to bear regulatory risk, especially with respect to the CPUC, given its past efforts that cut margins to suppliers and Energy Service Providers (ESPs). Note that there has been a significant decline in number of ESPs in California as a result of CPUC actions.
- Customer attrition risk is mitigated by the CCA establishing exit fees.²³ This approach to customer retention may be simplistic. If a major taxpaying entity

²⁰ After describing the IOUs' "extreme case" efforts opposing municipalization, NCI states that "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. [Ibid., p. 34, emphasis added]" MRW believes that it is more likely that the IOUs will find numerous creative ways (both subtle and obvious) in the regulatory and political realms to attempt to undercut the financial viability of CCAs.

²¹ For example, see Berkeley Study, p. 35.

²² Ibid, pp. 37-38. It is important to note that in the context of the Studies, risk mitigation is not the same as risk elimination. Thus, even after implementation of NCI's recommended risk mitigation measures, a CCA still faces downside (and upside) risks.

²³ Ibid, p. 38.

(e.g., a large industrial customer) in a city is interested in departing from CCA service, then that customer likely has significant political clout, which will make it difficult to simply “impose an exit fee.” The CPUC has imposed exit fees and has seen well-funded efforts to avoid those exit fees (with some success).

- Operational risk is mitigated by disciplined professional management.²⁴ It is important to note that it is not possible to completely avoid operational risks. As noted above, increasing gas prices will result in increasing market prices, which will decrease CRS but increase commodity purchase prices. Volatile gas prices will result in volatile CRS and volatile electric market prices. Hedging one risk exposes the CCA to other risks. Thus, it is not sufficient to say that professional management will mitigate risk. Instead, such an approach will, at best, reduce risk.
- Regulatory risk is managed primarily by participation in regulatory proceedings.²⁵ This is correct to a certain extent. However, mere participation in regulatory proceedings does not guarantee positive results for the participant and can be very costly.
- Financial reserves are an asset of the program and are ultimately accessible for future rate reductions or other purposes.²⁶ This is true to a certain extent (e.g., if banks require reserve funds as part of debt financing, then these funds will become available after the debt has been repaid). However, if the funds are set aside as a form of “self-insurance” then they will not be available to reduce rates.
- Phasing will reduce risk.²⁷ It is important to note that the issue of phasing has not been decided yet by the CPUC, it has only been postponed until the prospective CCA submits its Implementation Plan. At that time, the Commission may decide that the proposed phasing approach is inequitable and reject the Implementation Plan.

Recommendation: The risk assessment and risk mitigation approaches outlined in the Studies may understate the risks associated with CCA and overstate the ability of a CCA to eliminate those risks. A more rigorous vetting of the risks associated with CCA would be valuable, with particular attention paid to risks that cannot be fully mitigated. Such an effort is definitely needed in any Phase 2 assessment.

Conclusion

If you have any questions about this material, please feel free to give us a call at (510) 834-1999.

²⁴ Ibid, pp. 38-39.

²⁵ Ibid, p. 39.

²⁶ Ibid, p. 40.

²⁷ Ibid, pp. 40-41.

Attachment A: Adjustments to NCI's Projection of PG&E's Generation Costs

	nuclear	hydro	QF	total corrections	DC lic. Ext.	total with lic ext	Less hydro generation	total with lic ext and less hydro	Navigant estimate PG&E costs	corrections	% difference	
											w/ lic ext	w/ lic ext & less hydro
2004	(\$3,778)	(\$4,328)	\$0	(\$8,106)	\$0	(\$8,106)			\$5,081,916	-0.16%	-0.16%	-0.16%
2005	\$1,013	(\$1,365)	\$0	(\$352)	\$0	(\$352)	\$2,915	\$2,563	\$5,330,137	-0.01%	-0.01%	0.05%
2006	\$2,002	\$2,103	\$0	\$4,105	\$0	\$4,105	\$5,450	\$9,555	\$5,355,698	0.08%	0.08%	0.18%
2007	\$2,811	\$4,247	\$0	\$7,058	\$0	\$7,058	\$7,665	\$14,723	\$5,460,175	0.13%	0.13%	0.27%
2008	(\$29,952)	\$6,243	\$0	(\$23,709)	\$0	(\$23,709)	\$10,440	(\$13,269)	\$5,718,872	-0.41%	-0.41%	-0.23%
2009	(\$22,128)	\$8,106	\$0	(\$14,022)	\$0	(\$14,022)	\$13,400	(\$622)	\$5,861,047	-0.24%	-0.24%	-0.01%
2010	\$7,614	\$12,552	\$0	\$20,166	\$0	\$20,166	\$17,640	\$37,806	\$6,191,228	0.33%	0.33%	0.61%
2011	\$5,222	\$19,491	\$0	\$24,713	(\$11,193)	\$13,520	\$21,945	\$35,465	\$6,392,996	0.39%	0.21%	0.55%
2012	\$7,057	\$25,855	\$0	\$32,912	(\$100,037)	(\$67,125)	\$26,960	(\$40,165)	\$6,611,990	0.50%	-1.02%	-0.61%
2013	\$6,121	\$31,673	(\$9,072)	\$28,723	(\$92,204)	(\$63,481)	\$31,230	(\$32,251)	\$6,226,984	0.46%	-1.02%	-0.52%
2014	\$6,279	\$36,972	(\$20,533)	\$22,718	(\$84,878)	(\$62,159)	\$35,350	(\$26,809)	\$6,386,553	0.36%	-0.97%	-0.42%
2015	\$1,413	\$41,776	(\$30,789)	\$12,400	(\$76,538)	(\$64,138)	\$39,490	(\$24,648)	\$6,592,318	0.19%	-0.97%	-0.37%
2016	(\$8,280)	\$46,106	(\$41,082)	(\$3,256)	(\$67,139)	(\$70,395)	\$44,220	(\$26,175)	\$6,728,573	-0.05%	-1.05%	-0.39%
2017	(\$26,197)	\$49,985	(\$58,448)	(\$34,660)	(\$50,340)	(\$85,000)	\$48,295	(\$36,705)	\$7,051,495	-0.49%	-1.21%	-0.52%
2018	(\$95,599)	\$53,432	(\$67,019)	(\$109,186)	\$17,583	(\$91,603)	\$54,810	(\$36,793)	\$7,555,908	-1.45%	-1.21%	-0.49%
2019	(\$97,829)	\$56,466	(\$87,533)	(\$128,896)	\$17,986	(\$110,910)	\$64,050	(\$46,860)	\$8,009,533	-1.61%	-1.38%	-0.59%
2020	(\$99,166)	\$59,104	(\$110,392)	(\$150,455)	\$17,167	(\$133,288)	\$72,960	(\$60,328)	\$8,248,709	-1.82%	-1.62%	-0.73%
2021	(\$98,676)	\$61,362	(\$132,008)	(\$169,322)	\$14,220	(\$155,102)	\$79,050	(\$76,052)	\$8,284,442	-2.04%	-1.87%	-0.92%
2022	(\$94,257)	\$63,244	(\$136,798)	(\$167,810)	\$7,065	(\$160,746)	\$81,990	(\$78,756)	\$8,440,798	-1.99%	-1.90%	-0.93%
2023	(\$70,042)	\$64,797	(\$120,311)	(\$125,557)	(\$20,150)	(\$145,707)	\$86,830	(\$58,877)	\$8,832,692	-1.42%	-1.65%	-0.67%
2024	(\$71,243)	\$66,001	(\$95,721)	(\$100,963)	(\$36,046)	(\$137,008)	\$95,000	(\$42,008)	\$9,327,115	-1.08%	-1.47%	-0.45%
sum 2005-2024	(\$673,837)	\$708,151	(\$909,705)	(\$875,392)	(\$464,503)	(\$1,339,895)	\$839,690	(\$500,205)	\$138,607,263	-0.34%	-0.97%	-0.36%
NPV at 6%	(\$267,589)	\$318,334	(\$357,056)	(\$306,311)	(\$257,569)	(\$563,880)	\$375,999	(\$187,880)	\$75,220,838	-0.34%	-0.75%	-0.25%

Attachment B: PG&E's Class-Average Distribution by Rate Schedule

	E-1	E-1 Medical	EL-1	Total E-1	Total E-7, EL-7, E-8, EL-8	Total Class	Total Non-CARE, Non-Medical	Total CARE (including EL-7 and EL-8)	Total Medical (including E-7)							
Tier 1	13,323,087,650	61.97%	344,965,863	3,637,317,974	17,305,371,487	64.41%	669,510,401	30.78%	17,974,881,887	61.90%	14,291,105,024	59.76%	3,683,776,863	71.87%	364,609,453	83.55%
Tier 2	2,386,996,877	11.10%	30,320,468	447,345,294	2,864,662,639	10.66%	252,853,148	11.63%	3,117,515,788	10.74%	2,646,744,189	11.07%	470,771,599	9.19%	33,155,008	7.60%
Tier 3	3,184,079,598	14.81%	25,750,887	533,110,597	3,742,941,083	13.93%	452,609,770	20.81%	4,195,550,853	14.45%	3,622,045,341	15.15%	573,505,511	11.19%	28,581,133	6.55%
Tier 4	1,655,441,673	7.70%	7,205,100	237,687,355	1,900,334,129	7.07%	361,672,736	16.63%	2,262,006,865	7.79%	1,993,910,853	8.34%	268,096,012	5.23%	8,116,497	1.86%
Tier 5	950,064,287	4.42%	1,680,917	100,395,162	1,052,140,366	3.92%	438,276,426	20.15%	1,490,416,792	5.13%	1,361,229,778	5.69%	129,187,013	2.52%	1,956,812	0.45%
	21,499,670,085	74.03%	409,923,235	4,955,856,383	26,865,449,703	7.49%	2,174,922,481	29,040,372,184	23,915,035,186	82.35%	5,125,336,999	17.65%	436,418,903	1.50%		

UPDATED PRO FORMA FOR THE FORMATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM IN THE CITY OF BERKELEY

I. Introduction

In April 2005, NCI provided a feasibility study report for the City of Berkeley's potential formation of a Community Choice Aggregation (CCA) program. The study found the City could achieve significant benefits by forming a CCA program. These include electricity cost savings of approximately 6% under base case assumptions; increased use of renewable energy to serve customers within the City above the 20% minimally required of PG&E; enhanced rate stability; and expanded energy infrastructure. The report discussed certain risk factors that could modify the base case results and included sensitivity analyses that showed under some reasonably likely scenarios, program rates could exceed those of PG&E by 2% to 4% in the early years of the program. NCI recommended that if the City decides to form a CCA program, it should be prepared for the possibility that rates in the near term could exceed those of PG&E.

The City has requested a limited update to the pro forma to address changes in the following input assumptions:

- Higher natural gas prices and market clearing electricity prices
- PG&E's recently approved cost re-allocations among customer classes
- Delayed program commencement date to 2008
- Delayed resource on-line date to 2012
- Impact of the multi-tier residential rate structure and participation in the low income CARE program based on existing data possessed by the City.

NCI updated the pro forma analysis for changes in the variables listed above. In all other respects, the assumptions used in the April report are unchanged.

A revised pro forma consolidating the changed input assumptions shows CCA rates approximately 2% higher than PG&E rates for the first two years of the program; breakeven performance for the next two years; and surpluses beginning in 2012. Overall program savings for the forecast period are expected to total \$70.3 million or approximately 4% of total customer electricity costs. This

compares to \$99.3 million or 6% projected in the April report. The revised savings projections are shown below.

Table 1: Updated Pro Forma Summary

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
2008	40.7	3.0	1.5	5.6	0.5	0.2	51.5	49.4	(2.0)	-2%
2009	40.7	3.0	1.6	5.7	0.5	0.2	51.7	49.7	(2.0)	-2%
2010	40.7	2.9	1.6	5.8	0.5	0.2	51.8	52.0	0.3	0%
2011	41.2	3.0	1.6	6.0	0.5	0.2	52.6	52.2	(0.4)	0%
2012	33.5	3.0	1.6	6.2	0.5	4.9	49.8	52.4	2.6	3%
2013	34.9	3.2	1.6	2.7	0.5	3.8	46.8	50.5	3.7	4%
2014	37.8	3.4	1.6	2.8	0.6	3.7	49.9	53.2	3.3	4%
2015	38.6	3.5	1.7	2.8	0.6	3.7	50.8	54.2	3.4	4%
2016	39.7	3.6	1.7	2.8	0.6	3.6	52.0	55.2	3.2	3%
2017	34.0	3.6	1.7	2.9	0.6	7.1	49.9	56.0	6.0	6%
2018	34.8	3.7	1.7	2.9	0.6	7.0	50.8	56.9	6.0	6%
2019	36.5	3.9	1.7	2.9	0.7	6.9	52.6	59.3	6.6	7%
2020	38.9	4.1	1.8	3.0	0.7	6.8	55.3	63.0	7.7	7%
2021	42.5	4.3	1.8	3.0	0.7	6.7	59.0	66.1	7.0	6%
2022	44.1	4.5	1.8	2.9	0.7	6.5	60.5	68.1	7.6	7%
2023	45.8	4.7	1.8	-	0.7	6.4	59.5	67.8	8.3	7%
2024	47.4	4.8	1.8	-	0.8	6.3	61.1	69.8	8.7	7%
Total	672.1	62.2	28.6	58.0	10.3	74.3	905.5	975.7	70.3	4%

The largest impacts on program margins occur in the early years of the program, before the program acquires cost-based resources to serve its customers. In the discussion below, the impact on margins in the first year of the program (assumed to be 2008) is shown for each changed input assumption. The total impact over the entire forecast period from 2008 to 2024 is also shown.

Table 2: Decomposition of Margin Impact by Input Assumption

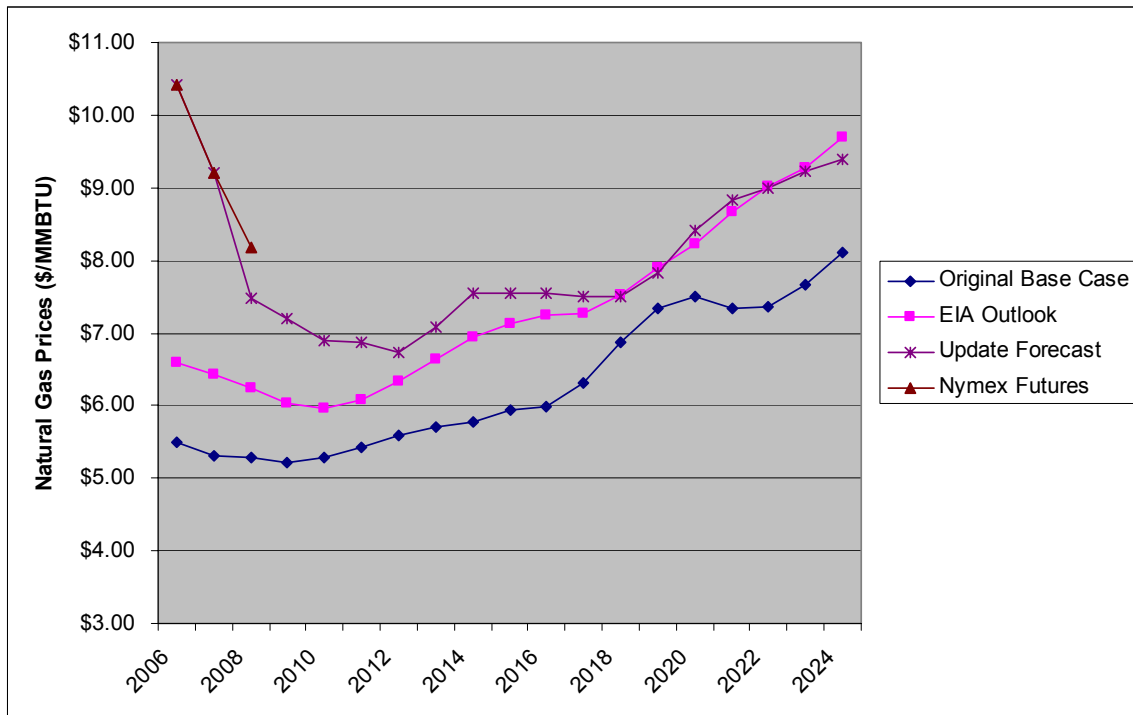
Input Assumption	2008 Impact (\$ Millions)	Cumulative Impact 2008 – 2024 (\$ Millions)
Natural Gas and Power Prices	(\$0.9)	(\$7.6)
Residential Tier Data	(\$0.2)	(\$8.5)
PG&E Rate Shift	(\$0.1)	(\$4.4)
Delayed Capital Investment	(\$2.1)	(\$8.5)
Total	(\$3.3)	(\$29.0)

II. Discussion of Individual Assumptions

Natural Gas and Power Prices

In the time since the report was completed energy prices have increased dramatically and are now at historically high levels. The run-up in petroleum prices during 2005 and the impacts of Hurricanes Katrina and Rita have caused both natural gas prices and wholesale electricity prices to increase significantly. NCI has revised its gas and power price projections upwards for the pro forma update, as shown in Figure 1. For reference, Figure 1 also shows futures prices on the NYMEX for the next three years and projections from the 2005 Energy Outlook published by the Energy Information Agency.²

Figure 1: Natural Gas Projections

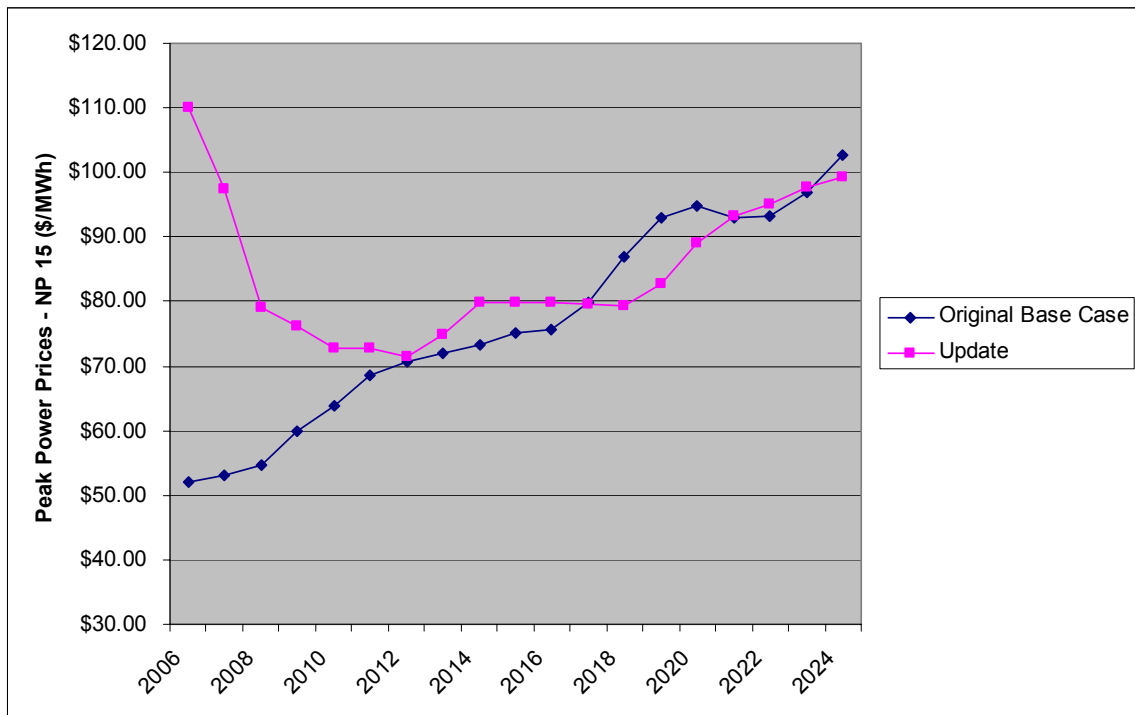


² EIA 2005 Annual Energy Outlook, natural gas price forecast for the electric generation sector in the Pacific Region. NYMEX prices were updated November 11, 2005 and are an annual average of the monthly prices which can be found at http://www.nymex.com/ng_fut_csf.aspx.

High fossil fuel prices will generally improve the long-run economics of the CCA program due to the assumed resource mix being comprised of 50% renewable energy. However, in the short-term, high fossil fuel prices negatively impact program economics because it will take time for the CCA to build a renewable resource base, and the CCA would need to buy energy from the market until it can begin producing its own electricity.

In response to suggestions from an independent review of the April report, NCI has also increased the assumed price of electricity for a given price of natural gas in the early years and reduced the price of electricity for a given price of natural gas in the later years of the forecast period. The original power price assumptions were intended to reflect excess capacity in the short-term and a market equilibrium supply/demand balance in the longer term. The revised power price assumptions reflect a more conservative view relative to the April base case assumptions because under the revised assumptions, generator profit margins are higher when the CCA is buying on the market and lower when the CCA is producing from its own resources.

Figure 2: Wholesale Market Prices Projections (NP 15 Peak)



For purposes of this analysis, NCI has set a floor price for renewable energy equal to the market price of conventional wholesale electricity. Therefore, the price of renewable energy purchased from the market is assumed to increase as fossil fuel prices increase because NCI expects that renewable energy producers would not sell electricity at a lower price than the prevailing market price of electricity produced from non-renewable sources. CCA ownership of the renewable resources, assumed to begin in 2012, enables the CCA to obtain electricity at cost, rather than at inflated market prices.

The impact of incorporating the higher natural gas and power prices is to reduce CCA margins by approximately \$0.9 million in 2008 or \$7.6 million through 2024.

Residential Tier Data

The City wished to examine the impact of the tiered rate structure for residential customers based on data possessed by the City regarding the distribution of residential usage among the five billing tiers in PG&E’s residential rate structure. Examination of the data shows differences between the baseline tier distributions within the City compared to the overall system distribution used in the April study. Residential customers within the City have proportionately more consumption within the lowest and highest usage tiers (Tier 1 and Tier 5) and less consumption within Tiers 2, 3 and 4.

Table 3: Residential Tier Data

Customer Base	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
PG&E Residential Class	59%	11%	16%	9%	5%
Berkeley Residential	63%	10%	13%	8%	6%

The impact of using the more detailed usage data for residential customers is a reduction to the calculated PG&E average rate charged to customers within the City of approximately 0.04 cents per kWh. This amounts to an approximately \$240,000 reduction to the CCA margins in 2008 or \$8.5 million through 2024.

PG&E Rate Changes

Changes to PG&E rates have also occurred subsequent to the report that will impact the projected economic benefits of CCA for the City. PG&E’s proposals to shift generation costs among customer classes were partially incorporated in a settlement approved by the CPUC in PG&E’s 2005 General Rate Case. The rate settlement reallocates generation costs among customer classes, generally increasing the share of generation costs paid by residential customers and decreasing the share paid by commercial and industrial customers. Considering the customer mix within the City, the new rate allocations tend to lower the overall PG&E rates against which a CCA program would compete. NCI included a sensitivity case in the April report to capture the risk that PG&E’s rate proposals were adopted in their entirety. The impact of the rate settlement is less severe than the sensitivity case presented in the April report.

The new PG&E revenue allocation reduces the average generation rate charged to customers within the City by approximately 0.02 cents per kWh. Based on projected electricity sales for 2008, this translates into reduced margins for the CCA of approximately \$125 thousand or \$4.4 million through 2024.

Table 4: Impact of PG&E Rate Settlement in 2005 General Rate Case

Customer Class	April 2005 Rate Design	GRC Settlement Rate Design 1/	Percentage Change	2008 Revenue Impact
Residential	6.035	6.670	11%	\$ 1,199,711
Small Commercial	7.508	7.180	-4%	\$ (328,648)
Medium Commercial	9.467	8.991	-5%	\$ (491,814)
Large Commercial	8.575	8.265	-4%	\$ (172,392)
Industrial	7.857	7.482	-5%	\$ (319,380)
Agricultural	5.443	5.040	-7%	\$ -
Outdoor Lighting	5.700	5.448	-4%	\$ (13,437)
Total				\$ (125,961) (0.00023)

1/ GRC Settlement rates from Advice Letter 2706-E, normalized to be revenue neutral to April 2005 rate levels.
 2/ Rates include Generation, CTC and Regulatory Asset cost components.

CARE Program

The CARE program offered by PG&E provides discounted rates to eligible low income electric customers. Currently, a portion of the CARE discount is reflected in generation rates, and the exit fee (CRS) that applies to CARE customers excludes the DWR power and DWR bond charge components. PG&E proposed in its 2005 General Rate Case to transfer the entire CARE discount to non-generation rates so that the CARE program would be competitively neutral with respect to non-PG&E generation service (i.e., CCA or direct access). However, the rate settlement reached in PG&E’s General Rate Case did not include the proposed changes to the CARE discount structure. Therefore, current rates continue to reflect CARE discounts in the generation rate. The CARE issue has been raised in the CCA rulemaking, and the Commission may determine that the CARE program should be operated in a competitively neutral manner in its forthcoming Phase 2 decision.³

NCI does not believe there is controversy regarding the need to restructure the CARE discount to non-generation rates; the issue is more a matter of process and timing. Each of the investor owned utilities either already reflects the CARE discount in non-generation rates or has proposed to do so. By 2008, NCI believes the CARE discount will no longer be reflected in PG&E’s generation rates. For this reason, NCI has not included the impact of CARE rates in the updated pro forma. To help the City understand the risk associated with this regulatory variable, NCI has calculated the impact of the CARE program if the discount were to be maintained in generation rates based on proxy CARE participation data reported by the City and County of San Francisco.⁴

³ The CPUC’s proposed decision in Phase 2, issued on November 2, 2005, requires the CARE discount to be reflected entirely in distribution rates. This change would make the CARE discount competitively neutral for the CCA.

⁴ CCSF Community Choice Aggregation Draft Implementation Plan, Chapter 2, Table 3, April 7, 2005.

Table 5: Impact of CARE Discount Based on Proxy Participation Data

Residential kWh	188,958,361
CARE %	11%
CARE kWh	20,785,420
CARE Generation Discount (cents per kWh)	-3.061
CRS Exemption (cents per kWh)	0.453
Net Generation Discount (cents per kWh)	-2.608
Revenue Loss	\$ (542,084)

If the CARE discount persists in generation rates in 2008, the impact is expected to be a reduction in CCA margins of approximately half a million dollars per year.

Timeline for Implementation and Resource Acquisition

The City also wished to examine risks associated with delays in acquisition of resources by the CCA. The program start date has been pushed back by two years to 2008, and the timing for CCA resources to come online has been pushed back four years to 2012. The implication is that the CCA program would be dependent upon purchases from the wholesale markets for the first four years of program operations.

The delay in capital investment for CCA resources results in a reduction in CCA margins of approximately \$2.1 million in 2008 or \$8.5 million through 2024.

III. Conclusion

The feasibility analysis has been updated to address specific changes in market conditions, PG&E rates and timing for resource investments. The total impact on the projected cost comparison between CCA service and PG&E service is a reduction in margin of approximately \$29 million over the 17 year forecast period, to approximately \$70 million. The revised margin estimate is approximately \$4 million per year, equivalent to 4% savings on electricity costs. The revised assumptions yield estimates for CCA rates that are slightly higher than the comparable PG&E rates for the first two years of program operations.

Cost savings begin to accrue in the fourth year, when production from CCA resources is assumed to become available to serve a portion of the program's electricity requirements. These results generally fall within the range of sensitivity cases presented in the original April report.