
Review of the Business Plan for the Marin County Community Choice Aggregation Program

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I. Introduction

JBS Energy was asked to review the Draft Report – Marin, California Community Choice Aggregation Business Plan, prepared by Navigant for the Local Government Task Force.

Overall, the report provides a reasonable basis for going forward. If conditions do not develop as expected, there are clear off-ramps for the County to stop going forward with the CCA.

The plan does not rely on a “beat the index” strategy of trying to beat PG&E’s short-term procurement costs. Instead the plan provides for a more sustainable strategy. This strategy, first, emphasizes renewable resources over fossil-fueled generation, placing Marin in the forefront of a movement away from fossil generation of electricity. Second, the plan correctly recognizes that community ownership of the bulk of such resources through the CCA is a critical way to stabilize future energy prices.

These comments do not emphasize the large areas of agreement that we have with the Business Plan. Rather, they point out a few areas of clarification to the plan and discuss a number of issues related to the CCA concept that may not need to be in the plan itself but should be understood by stakeholders.

II. Customer Interface Issues

The first issues we address are how customers are signed up for CCA service and treatment of customer deposits and the potential for future termination charges. Some items where the business plan should be clarified are identified.

A. Initial Rate Options at Time of Sign-Up

The analysis contains percentages of customers expected to sign up for the 100% renewable and “Light Green” Tariffs. The business plan should make it clear that at

least initially, PG&E's CARE¹ customers would be defaulted to sign up for the then-cheaper "Light Green" service.

After the program has been operational for a period of time, and particularly after the CCA's renewables have come on line, the benefits of providing renewables to CARE customers (possibly with some subsidy from the general body of ratepayers) could be reconsidered.

B. Customer Deposits (Page 88)

The business plan claims that customers may be required to post a deposit equal to two months estimated bills under the expectation that the CCA will have a similar credit policy to PG&E's policy. The deposit policy should be somewhat clearer in the business plan. We presume that PG&E will be physically collecting the money, since it collects all other money related to the CCA bills.

The CCA will need to establish a policy as to how long it holds deposits, whether it will pay interest on deposits, and how it will give them back to customers. [I would recommend that the CCA follow PG&E's practices.] It will also need to have a protocol for investing the money from deposits in short-term instruments or using it to offset line-of-credit short-term borrowings. None of these issues need to be decided at this stage, but the business plan should briefly identify these as issues for decision and implementation during the CCA start-up process. It may also be possible for PG&E to manage deposits for the CCA for a fee.

There is also a transitional issue - what happens to customers who already have deposits with PG&E at the time the CCA is started - will the PG&E deposit be pro-rated between the CCA and PG&E based on generation versus other revenues, or will PG&E keep its full deposit, leaving the CCA at risk (so that the CCA to mitigate its risk would have to ask some of its customers for even more money). Other alternatives are also

¹ CARE (California Alternative Rates for Energy) customers are residential customers who sign up for a discounted rate. Eligibility is based on income is less than 200% of the Federal poverty level. Certain commercial customers who serve low-income people (such as homeless shelters) also receive CARE discounts.

possible (such as PG&E continuing to hold the full amount of these deposits from existing customers but applying them to both CCA and PG&E revenues).

Here are PG&E's rules on deposits. <http://www.pge.com/tariffs/pdf/ER7.pdf>

C. Termination Charges (page 85)

The business plan outlines the potential for termination charges for customers leaving the CCA. These comments provide some perspective on the issue.

First, it is our understanding that the CCA is not intending to assess termination charges on customers who move out of a premises and into a new premises (either inside or out of the CCA service area) or who stop taking service permanently because of death or business closure. That point should be made specifically in the business plan, so that customers do not erroneously think that they need to stay with PG&E to avoid charges if they move or their business closes.

Rather, the purpose of the termination charge is to address large-scale movement of revenues from the CCA to the utility or other retailers such as Direct Access providers² under extremely adverse conditions that could jeopardize repayment of CCA debt or contract obligations. The CCA's revenues are calculated to include reserves that allow for normal "churn" over time.

The need for a termination charge could occur in particular if the market price for conventional power falls dramatically; for example if natural gas prices fall and global climate change were no longer deemed to be as significant an issue. This circumstance could cause CCA's renewable power to be more expensive than gas-fired power. Because the CCA is proposing to own generation, the risk of an event like this would be higher early in the program (either before the CCA has built its own power and is relying on shorter term contracts or shortly after it has built its own renewable generation but before it has paid a significant portion of its costs down and before

² Direct Access providers are competitive retailers who serve individual customers. At the moment, new Direct Access is not permitted for customers who were not served with Direct Access in September, 2001 until CDWR power contracts expire. However, the California PUC is considering methods to reopen Direct Access.

inflation has increased PG&E's costs. When a CCA has built its own generation at cost of service and depreciated it for a period of time the potential for its generation becoming more expensive than PG&E's generation will decrease.

If Direct Access were to be legalized and were to be significantly cheaper than PG&E power (because of a shorter term emphasis or a reduction in required reliability for DA), the CCA could also see its revenue stream placed at risk.

The size of a termination charge depends on the difference in value between CCA power and the market price. It certainly will not be the full cost of CCA power, but will reflect the difference between the cost of CCA power and its value in the open market (including not just the market price and the value of any renewable energy credits or RECs³).

III. Other Issues Related to Financial Projections

A. Load Forecast

The load forecast has been revised downward since the initial feasibility study. This type of revision appears reasonable given that Marin is not growing quickly. Our comment on enrolling CARE customers in the light-green tariff is presented above.

B. Cash Working Capital(page 72)

Cash working capital should be based on more than 47 days. The average number of lag days between meter read and billing is between 27 and 28 days.⁴ This translates into about 42-43 days from mid-month but to 57-58 days from program start-up.

C. PG&E Rate Projections

In the Marin County business case, Navigant has started with PG&E's 2008 generation rates and increased PG&E's generation rates by 3.5% per year. This is a reasonable long-

³ For definition of RECs, see Footnote 7.

⁴ PG&E response to TURN Data Request 4-54 in 2007 TY GRC.

term approximation, because previous Navigant analyses have shown PG&E-owned generation costs increasing at about 3% per year and new market-priced generation costs per kilowatt-hour increasing at about 4%. If anything, Navigant's assumption may be conservative given new cost-increasing mandates such as renewables, resource adequacy and possible treatment of GHG costs (see below), as well as the increase in higher cost renewable and gas generation as load grows on the PG&E system.

PG&E is also expecting a significant increase in generation costs for the years 2008-2010 due to CDWR's renegotiation of the Calpine contract (that eliminated a benefit of about \$10/MWh to PG&E from 2008-2010). While this does not affect the long term, it does show that Navigant's ramp-up of PG&E's generation costs, starting from 2008, is likely to be conservative.

However, overall, one must recognize that PG&E's generation rates will be volatile. PG&E's rates will fluctuate with gas prices and will be higher with higher gas prices. They will be lower with lower gas prices; in addition costs of the powerplants that PG&E buys and owns will affect volatility. This issue will be further addressed in Section VI, the discussion of risks.

D. Treatment of CCA Cost Responsibility Surcharge

The CCA Cost Responsibility Surcharge contains four components – the CDWR⁵ bond charge; the Energy Crisis Recovery Surcharge; the Competition Transition Charge (CTC), and the Power Cost Indifference Adjustment (PCIA). The first three of these components do not affect CCA rates directly, as they are part of both bundled and CCA rates. However, the CTC charge, which is calculated mechanically, means that when PG&E's gas costs are lower, the CTC charge rises and the generation rate is reduced. The Power Cost Indifference Amount is currently based on CDWR costs, although certain PG&E costs for new long-term contracts or PG&E-owned plants up to the date of CCA formation can be included in the PCIA. The sum of the PCIA and CTC cannot be less than zero.

⁵ California Department of Water Resources.

The CCA Cost responsibility surcharge and PCIA are mentioned in the Navigant report but are not considered in the development of financial statements, because the charges expected by PG&E in 2007, when the report was being prepared were insignificant (0.004 cents/kWh) per Advice Letter 3002-E. In 2008, the Direct Access (DA) PCIA is about negative 0.02 cents per kWh (Advice Letter 3115-E-A); the CCA PCIA should be similar.⁶

However, the PCIA could become positive with a combination of a decrease in gas prices and market energy prices and an increase in PG&E's costs (for example after PG&E builds new powerplants). A positive PCIA is not included in Navigant's projections based on current information, but it is a risk that could be faced by the CCA in future years if gas prices fall significantly. Moreover, the PCIA for a CCA is vintaged. It can theoretically include all PG&E power commitments up to the point when the CCA is established. At the present time, this includes PG&E powerplants approved by the CPUC for construction by about 2010. By establishing a CCA before PG&E makes more commitments, those commitments could not be charged to the CCA through the PCIA.

The calculation of both PCIA and CTC is tied to a methodology established in 2005 that appears to understate market prices for CCAs and overstate their cost responsibility. Specifically, market prices used to compute "indifference" are based on a 24X7 block of power (even though a CCA has more peaked loads) and the market price excludes costs for ancillary services and ISO charges that both utilities and CCAs must provide or pay for. Any changes made to this methodology will make any future potential PCIA less onerous.

⁶ PG&E's tariffs show a sum of PCIA and CTC of 2 cents per kWh, but this figure is a placeholder that does not represent the true costs that PG&E might impose. See PG&E Advice Letter 3115-E-A, page 11, footnote 7.

IV. Resource Procurement Strategies

A. Renewable Resources

In the near term, renewable procurement would come from a mix of shorter term contracts, renewable energy credits (RECs)⁷, and expiring QF⁸ contracts. In the longer term, Marin County proposes to own significant amounts of resources (modeled for financial purposes as 150 MW of wind and 50 MW of biomass) and to contract for additional renewable power. The emphasis on ownership provides long-term benefits to the CCA, which will own projects on a cost-of-service basis for many years – longer than typical 10-20 year contracts (like those being signed by PG&E).

We have reviewed the scenarios of renewable project costs for projects owned by the CCA. The project costs generally appear conservative and would lead to competitively priced power. The cost of integrating wind power into the grid (\$25/MWh) appears high to us but use of a conservative assumption is appropriate in this context. However, it appears to us that Navigant's estimate of debt service costs may be about 10% low, assuming an interest coverage ratio of 1.25; using mortgage amortization of costs; and assuming that Navigant's costs are in 2014 dollars, not 2008 dollars.⁹

⁷ When renewable energy is generated, it produces both energy and a REC – a credit that recognizes that the renewable energy was generated and its differential value relative to conventional energy. The REC can be kept with the generation, but it can also be sold separately from the energy under carefully defined conditions that prevent RECs from being counted more than once. While in the long run, Marin County will procure renewable energy from projects that it owns or contracts for on a fairly long-term basis, RECs can provide a short-term source of renewable energy (before projects come on line). They also provide a daily or hourly balancing of renewable energy to actual power use. For example, the CCA could sell renewable power that was surplus to its needs in a given hour into the market but keep the REC (which the CCA would own because it generated the power or bought it under long-term contract). The CCA could then use the REC later to cover gas-fired generation that was acquired to follow load or meet local reliability requirements.

⁸ Qualifying Facilities are independent power producers who produce power using cogeneration or renewable resources. A large amount of QFs were signed up under long-term utility contracts in the 1980s; many contracts will expire from 2010-2020..

⁹ While Navigant assumed that accumulated reserves will provide the debt coverage required, this analysis, more conservatively, does not assume that accumulated reserves will provide debt coverage. However, we are not suggesting that Navigant's scenario is incorrect.

The cost of the CCA's owned renewable power, including wind integration costs, rises from 8.3 cents/kWh in the first year of ownership to over 11 cents near the end of the project life.

While the business plan has identified a mix of purchased and owned resources, with the owned resources modeled as wind and biomass, the Marin CCA has the ability for relatively flexible renewable procurement. First, because the whole CCA peak demand is on the order of 250 MW, the CCA has the ability to procure (either by purchasing or even owning) smaller projects that may be of little interest to a larger entity such as PG&E. The CCA can also work on developing local resources from within the county (e.g., landfill gas, wind). Once the CCA exceeds the 20% California renewable standard, it also can procure renewables flexibly (i.e., by buying from out-of-state, using contracts of varying lengths, buying RECs, or by buying or contracting for projects that use renewable resources but otherwise may not qualify under the California RPS).

The CCA also has the ability to enter into Joint Powers Authority (JPA) arrangements with other CCAs that might be formed or with municipal utilities (such as the Sacramento Municipal Utility District or the Northern California Power Agency) to buy smaller pieces of larger renewable projects. Such arrangements diversify operational risk across a number of projects and reduce credit exposure through use of JPA project financing backed by long-term power purchase agreements with the JPA members to cover the cost of the assets.

Finally we note that "100% renewable power" means that the CCA will procure renewable resources sufficient to meet the energy loads of renewable customers. This does not mean that every hour will be perfectly balanced using only renewables; in some hours, the CCA will buy some fossil resources; in other hours, the CCA will sell excess renewable resources into the market (while keeping the RECs to offset the fossil resource use in other hours). Any imbalance after this process is done can be made up with REC purchases or sales. The \$25/MWh wind integration cost included in the analysis includes costs related to this balancing function.

B. Role of High Efficiency Cogeneration

While the key objective of the Marin CCA is to own renewables and provide renewable resources to its customers, distributed generation provided by high-efficiency cogeneration deserves emphasis in some specific cases. Hospitals and other large medical centers, large office buildings, and manufacturing facilities often have cogeneration potential. In particular, in hotter parts of the County, a well-designed cogeneration project can use waste heat to produce chilled water that, in turn, displaces demand for air conditioning.¹⁰ The CCA should consider high efficiency distributed cogeneration in appropriate locations as a means of meeting Bay Area local generation requirements, serving local businesses and agencies with inexpensive energy for heating and cooling, reducing air conditioning peak demand, and saving energy relative to utility gas-fired generation. This energy could be provided to light-green-tariff customers while serving other strategic interests of the CCA, the County, and its businesses.

C. Energy Efficiency and Demand Response

The CCA is considering taking over certain energy efficiency and demand response programs. The County has a local government program for efficiency and could use that experience, as well as experience in what is not being done well because of PG&E's restrictions on its program, to develop CCA-based efficiency programs in the longer term. CCA programs could also be targeted to entities such as government agencies and non-profits to reduce their operating costs.

However, it appears to us that demand response programs, in particular, might be amenable to some type of outside contracting, because of specialized knowledge and expertise. Key areas for consideration in development of demand response should be "double-dip" programs, which have energy efficiency or other bill savings benefits that will cover a significant portion of the program's costs while providing dispatchable

¹⁰ As an example, the UC Davis Sacramento Medical Center has a cogeneration facility that produces about 25 MW. The waste heat is used to produce chilled water that reduces the facility's air conditioning load by 8 MW more in the summer months, as well as reducing natural gas use for heating and hot water during the remainder of the year.

demand response for the CCA. Examples of these types of double-dip programs are variable speed drives for HVAC systems in large office or institutional buildings (which save considerable amounts of off-peak energy by reducing fan speeds consistent with the reduced need for heating and cooling but which also allow fan speeds to be turned down to save energy during critical peak conditions) and programs in convenience stores to modulate equipment operations (which (a) save some energy; (b) reduce non-coincident demand charges (part of PG&E's transmission and distribution rate design – not the CCA rate design), and (c) provide dispatchable demand response). Water agencies also can often develop demand response capabilities if changes in water delivery patterns are made, often coupled with investments in additional water storage in key areas. The CCA could consider partnering with these agencies to fund such programs if cost-effective.

V. Risks Facing the CCA

A. Potential for PG&E Rates to Be Lower than CCA Rates

The CCA is deliberately structuring its rates so that its full green tariff will be more expensive than PG&E rates in the near term until it can bring plants into ownership and provide the cost-reducing effects to its customers. It proposes to match PG&E rates with the “light green” tariff. Because of the emphasis on ownership of renewables to provide long-term price stability, imbalances between PG&E rates and CCA rates may prove less important than in other areas, as customers will be informed that they will pay more for renewables near term in exchange for longer term advantages – both economic and environmental.

Nevertheless, it is important to recognize when such imbalances could occur. The CCA in the near term will be attempting to purchase a largely hedged full requirements product with significant renewable energy. As a result it is unlikely to be faced with price spikes such as those that occurred in 2000-2001. On the other hand, neither is PG&E.

The key areas that could create such imbalances are hydro conditions (temporary), and gas prices. These issues will be discussed below. Other areas that could reduce PG&E rates relative to the CCA would be a change in regulatory policy to reduce PG&E's return on equity (which could particularly affect the new gas-fired generation that it proposes to own). Such a policy is unlikely in the next several years but could arise later.

Regarding hydro conditions, 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.¹¹ Simply due to hydro conditions, we previously estimated (after reviewing the feasibility study) that PG&E's costs can fluctuate by plus or minus 6.2% from the wettest or driest year of record to the average. 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 ERRA¹² 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.

Regarding gas prices and market prices, both PG&E and the CCA have some exposure to gas prices in the near term. While the CCA will be developing a renewable product based heavily on local ownership, in the short term, it will likely be purchasing some renewables on contracts of varying lengths, as well as generic market-based energy backed by RECs. Its costs are likely to be higher than PG&E's because of the greater expense of renewables and the cost of RECs added to market-based energy.

In the long-run, expectations are that renewables owned by the CCA will be cheaper than market energy because the CCA has a lower cost of money than PG&E and because

¹¹ Based on PG&E hydro generation data used to develop W. Marcus and R. Kinosian, *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.

¹² The Energy Resource Recovery Account (ERRA) is PG&E's rate to collect fuel and purchased power costs.

the CCA will be dramatically reducing its use of high-cost and volatile natural gas through its renewable purchase strategy.¹³ However, imbalances could develop if (1) gas prices turned out to be considerably lower than expected; or (2) renewable performance turned out to be lower than expected; or (3) regulators changed the rules to make reliability less paramount so that future Direct Access providers could offer less expensive products on an expected value basis.

The CCA's risk of renewable performance can be reduced through diversifying into a number of projects rather than purchasing a only a few projects that are large relative to the size of the CCA, as well as by joint venturing with others to purchase shares of larger renewable projects.

B. Regulatory Risks

There are a series of rate design risks associated with the provision of CCA service.

The design of rates by customer class could affect CCA economics. The CCA analysis prepared by Navigant is based on PG&E's 2008 rates.

First, PG&E is considering the possibility of placing all residential tier inversion in the distribution rates, rather than having tier inversion in both generation and distribution rates. This change would have a minor adverse impact on the Marin CCA (reducing PG&E's residential generation rate by about \$1/MWh) but would have larger negative impacts on the San Joaquin CCA and positive impacts on the San Francisco and East Bay CCAs. Long term, such a change would beneficially reduce risk to the CCA. While there is a small direct economic detriment from the rate design shift, the shift would mean that CCA economics would no longer be dependent on changes in residential rate design made for other reasons without regard for impacts on CCAs that would be of secondary importance to the decision-makers.

¹³ As noted in Section IVA above, in order to follow load and meet reliability requirements, the CCA may still be buying gas-fired energy in some hours and selling excess renewable energy (after retaining the REC) in other hours.

Second, it is likely that in about 2011 (next General Rate Case Phase 2), PG&E will undertake some further rate realignment. While this realignment would be contested, it is likely that PG&E will propose a method that could raise residential generation rates and lower generation rates for other customer classes. Since the Marin CCA has a higher fraction of residential load than the PG&E system as a whole, this change could provide the CCA with more competitive breathing space in the aggregate, even while creating a need to reduce commercial/industrial rates to remain competitive.

Navigant has correctly addressed the issue of PG&E's Advanced Metering Infrastructure (AMI) program. (page 78) It brings with it issues that could cut both ways on CCA economics. The first issue is load profiling. The CCA is currently required to balance its loads based on dynamic system-wide load profiles for customer classes as a whole. These load profiles are more peaked than the actual loads of Marin County residential customers because they include a disproportionate number of customers in the hotter portions of the PG&E service area. With advanced metering, Marin's own load profile would become known and could be used, reducing the CCA's costs. However, regulatory action would need to be taken to enable a CCA to use actual costs, and there might be opposition both from other CCAs (such as the San Joaquin Valley which would be disadvantaged by use of actual data) and possibly PG&E (which might argue that allowing entities such as Marin, East Bay, and San Francisco, to cherry-pick non-peaked residential loads for CCAs could unfairly raise costs for its other residential customers). This particular impact of AMI essentially means that the status quo assumed by Navigant is a worst-case scenario and a change to use actual data instead of load profiles could benefit the CCA.

A second regulatory risk of advanced metering relates to Critical Peak Pricing or Peak Time Rebates - programs to offer incentives to reduce load during up to 100 critical peak hours per year.¹⁴ PG&E will offer such a "dynamic pricing" rate design. It is likely that the rate design will not be cost based in two ways. First, the rate design is likely to hand

¹⁴ A critical peak pricing rate offers a higher rate during these hours; a peak-time rebate offers a rebate if a customer reduces load below a pre-determined level based on loads on similar recent days.

out too much money (i.e., by being based on the full cost of a peaking powerplant, even though the CCA might not be able to avoid the full cost of a peaking plant by reducing demand) or use a Central Valley load profile to make it more likely that customers will sign up for the program (as PG&E proposed in its original Advanced Metering application). These rates are proposed for both residential and non-residential customers. A Central Valley load profile applied to Marin County would create “structural benefiter” from the PG&E program (less politely known as “free riders”). If non-cost-based rates or rebates are included as part of PG&E’s generation rate instead of its distribution rate, the CCA may have difficulty offering similar rates or competing with subsidized PG&E service. For non-residential customers, Navigant’s relatively conservative assumptions regarding participation rates may cover some of these potential losses; but the issue may create risks to the CCA with respect to residential customers.

VI. Risks of Not Adopting the CCA and Maintaining Status Quo of PG&E Service

The development of a CCA obviously creates risks for its customers, but there are also risks associated with PG&E service. Some of the risks are the other side of the coin of CCA risks (high gas prices would make the CCA more attractive relative to PG&E in the long run because of its heavy emphasis on renewables that are owned by the CCA to create long-run value to customers). While gas prices expose both PG&E and the CCA to risk, the CCA is taking a long-term position to hedge this risk physically (as well as hedging climate change risks) through ownership of new renewable generation. PG&E will be buying and building significant amounts of new gas-fired generation beyond its Renewable Portfolio Standard (RPS) requirements. Essentially, the CCA’s prices are likely to be lower relative to PG&E’s at times when gas prices are high (and utility costs would be a larger burden on consumers as a result). Conversely, as discussed above, the CCA’s prices could be higher relative to PG&E’s if gas prices are low (and overall utility costs are less of a burden).

Aside from gas prices, some other risks of the status quo are very specific to PG&E. While the CCA is largely competing with PG&E’s gas-fired generation (as it allows

PG&E's nuclear and hydro generation that is currently cheaper than gas to be used to serve other PG&E customers), the cost trends in this other generation affect PG&E's generation rates and costs with which the CCA must compete.

PG&E's system is dependent on contracts for its renewable resources, while the CCA ultimately plans to own a significant portion of its renewables. When those contracts expire, PG&E will need to recontract at higher prices. The CCA will not face the same increases. This is a growing advantage to the CCA over time, although it does not arise until after about 2020.

PG&E's system is also dependent on the performance of Diablo Canyon. Unlike a gas-fired combined-cycle plant, where the primary uncertainty is natural gas pricing, nuclear units face unanticipated capital expenditures, new regulatory requirements related to safety, and potential extended shutdowns. The unit is already expected to have well over \$1 billion of capital expenditures between now and 2011, including over \$700 million on steam generator replacement alone. An extended nuclear outage, covering a year, would result in replacement power costs of \$600 million per year per unit assuming replacement power costs in the range of \$70/MWh, plus the extra costs of dealing with the outages. While PG&E's nuclear performance has been relatively good in the recent past, the rising costs together with the statistical consideration that performance can fall far more than it can increase provide an advantage to the CCA relative to the status quo. In other words, nuclear plant operations are more likely to result in higher costs for PG&E than expected, relative to lower than expected costs). There are two components of this status quo risk – a likelihood that the overall cost of Diablo Canyon will rise over time and the potential for sharp cost increases in the event of any unforeseen problems.

PG&E officials have also stated that *new* nuclear generation should be considered as a key mechanism for reducing Greenhouse Gas emissions going forward.¹⁵ However, nuclear generation is likely to be more expensive than both gas and renewables.

¹⁵ David R. Baker, PG&E Looking at Nuclear Plants, San Francisco Chronicle, November 29, 2006. <http://www.sfgate.com/cgi-bin/article.cgi?f=/c/a/2006/11/29/BUGPNMLIAH1.DTL>

Harding, for example, estimates a capital cost of \$4540/kW starting with data from eight recent Asian nuclear plants. This translates into a life-cycle capital cost in 2007 dollars of 9.4 to 12.2 cents/kWh – of course escalating to the time when the generation would actually come on line.¹⁶ This is a risk after 2015-2020 to which CCA customers will not be exposed.

Moreover, while PG&E's hydro remains cheap, its costs are also rising. PG&E's hydroelectric operating expenses were projected to rise by 57% more than inflation from 2004-2009.¹⁷ Its hydro capital expenditures, which averaged \$47 million per year from 2001-2004 have risen to an average of \$88 million in 2005-2006 and a forecast average of \$110 million from 2007-2009.¹⁸ In addition to rising costs, PG&E is also likely to face slowly declining hydro energy production slowly over time (with replacement power provided by gas-fired resources). The two reasons for this decrease are (1) changes in streamflow regimes as plants are relicensed that reduce the availability of water to generate power; and (2) global climate change that could reduce rainfall and change precipitation patterns to the detriment of hydro production. This status quo risk is likely to result in a gradual increase in PG&E's costs up relative to the CCA's.

When PG&E does build resources, its cost of capital is considerably higher than that of the CCA, which is largely financed with tax-exempt debt. PG&E's cost of capital is between 12 and 13% including equity, debt, and income taxes. The CCA's cost of capital is assumed (reasonably) by Navigant to be in the range of 5.5% for debt. Additional amounts of money must be collected from customers to maintain appropriate interest coverage ratios on the debt (about 1.25 times debt interest), raising the near term cost of capital to about 7%. However, that money, once collected, can be reinvested in the CCA's operations (by some combination of paying down debt, building rate stabilization reserve funds, or making equity investments in new renewable or efficiency

¹⁶ Jim Harding, Economics of Nuclear Power and Proliferation Risks in a Carbon Constrained World, Presentation to California Energy Commission Docket 2006-IEP-1, June 28, 2007.

¹⁷ PG&E 2007 TY General Rate Case, Exhibit 3, Chapter 4 (Hydro Operations program Costs), Table 3-2, p. 3-63.

¹⁸ PG&E 2007 TY General Rate Case, Exhibit 3, Chapter 4 (Hydro Operations program Costs), Table 3-1, p. 3-62. and PG&E 2003 TY GRC Exhibit 10, Table 3-1, p. 3-54.

projects). The CCA's ownership strategy thus is likely to provide benefits relative to the status quo.

Finally, PG&E is also expecting a significant near-term increase in generation costs for the years 2008-2010 due to CDWR's renegotiation of the Calpine contract that benefitted PG&E. While this does not affect the long term, it does show that Navigant's ramp-up of PG&E's generation costs, starting from 2008, is conservative.

VII. Conclusion

We appreciate the opportunity to review the CCA Business Plan. It appears generally well thought out to provide Marin County with a portfolio of future sustainable resources that would be unique in the nation at this time at costs that are not unreasonable when compared to PG&E's expected costs.