



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

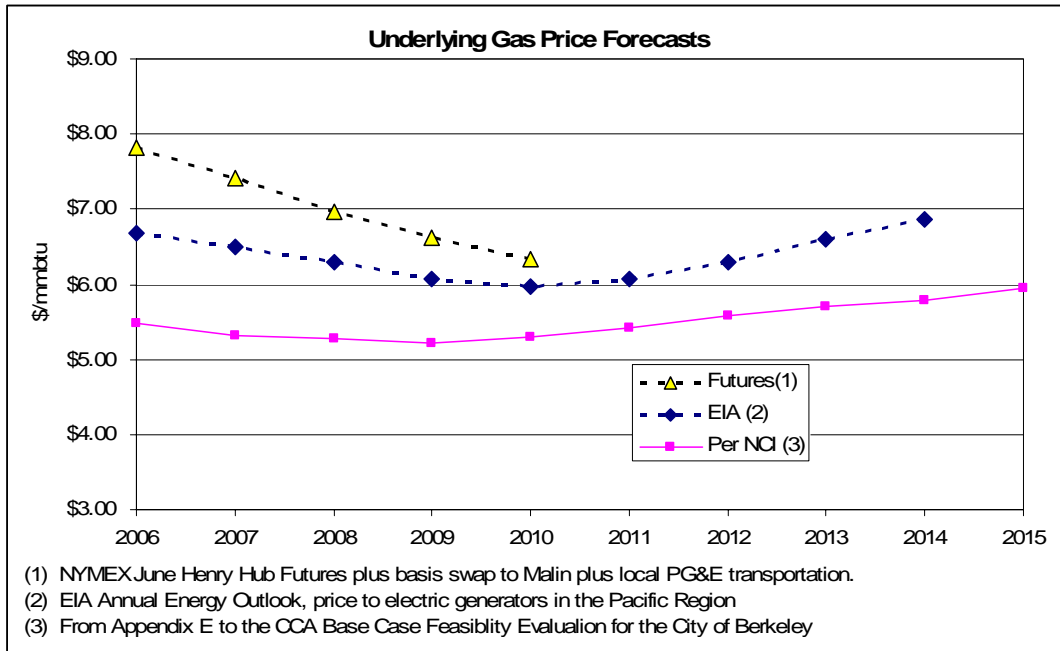
Gas prices have been highly volatile over the past several years. As a result, it is expected that any point/line forecast of gas prices is likely to be incorrect in the future. Given the changes in natural gas prices over the past six months, it is not surprising that the view of the gas markets today 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)		(\$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	92.51%	2,174,922,481	7.49%	29,040,372,184	23,915,035,186	82.35%	5,125,336,999	17.65%	436,418,903	1.50%	