

THE ECONOMICS OF COMMUNITY CHOICE AGGREGATION

The Municipalization of Local Power Acquisition and Production



Bay Area Economic Forum

**A Partnership of the Bay Area Council
and the Association of Bay Area Governments**

June 2007

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The Bay Area Economic Forum

The Bay Area Economic Forum is a public-private partnership of business, government, university, labor and community leaders that develops and implements projects that support the vitality and competitiveness of the state and regional economies, and enhance the quality of life of their residents. Sponsored by the Bay Area Council, a business organization of more than 250 CEOs and major employers, and the Association of Bay Area Governments, representing the region's nine counties and 101 cities, the Bay Area Economic Forum produces economic policy analyses and provides a shared platform for leaders to act on key issues affecting the future of the Bay Area economy.

TABLE OF CONTENTS

INTRODUCTION	1
Background	3
Key Elements of AB117 and CPUC CCA Implementation Rules.....	3
<i>Cost Responsibility Allocation:</i>	4
<i>Consumer Participation Options</i>	5
IOU/CCA Relative Taxation and Capital Structure	7
Comparative Cost and Benchmark Models	8
Northern California CCA Cost Benchmarks Against PG&E Retained Generation Costs	17
<i>Nuclear Production Cost</i>	18
<i>Hydro Production Cost</i>	18
<i>Steam Production Cost</i>	19
<i>Generation Average Cost</i>	19
<i>CCA Owned Generation Benchmarks</i>	19
CCA Generation Potential	21
Conclusions	22
Appendices	
<i>Appendix I: Glossary of Terms</i>	25
<i>Appendix II: PG&E Generation Average Rates</i>	26

Introduction

Community Choice Aggregation (CCA) is a program established by the California Legislature in 2002 (AB 117) that authorizes local public agencies to aggregate the electricity loads of residents, businesses and municipal facilities under its local jurisdiction, and to take over (municipalize) the power acquisition function currently performed by the investor-owned electric utility company (IOU) for those customers. Community Aggregators or CCAs have the options of supplying power through wholesale purchase contracts and spot market purchases and/or through ownership and operation of generating plants. However, the responsibility for all aspects of power delivery (transmission, distribution, metering, billing, and customer service) remains with the utility.

Proponents of forming CCAs claim opportunities to reduce electric bills, gain greater local control of energy supply decisions, obtain better rate stability, achieve environmental goals, plus an extensive list of other benefits for CCA customers¹. Several California communities have examined CCA opportunities to the extent of commissioning consultant feasibility studies, and one community has developed an Implementation Plan that has been submitted to, and was recently approved by, the California Public Utilities Commission². The consultant reports have provided forecasts of relative CCA/IOU rates associated with varying assumptions about the potential performance of CCAs versus utilities in purchasing power from the competitive forward and spot electricity markets, and the potential for CCAs to obtain lower production costs from CCA owned generation relative to utility owned generation. Given the volatility of energy markets, the imperfections in energy market models, the potential for considerable variability in forecasting assumptions

¹ See for example, ***Community Choice Aggregation Plan***, City and County of San Francisco, April 17, 2007 and, ***Base Case Feasibility Evaluation-Marin County***, Navigant, March 2005

² The San Joaquin Valley Power Authority, ***Community Aggregation Implementation Plan and Statement of Interest*** has been approved by the CPUC,

and the long-term commitments involved in energy procurement, communities should carefully examine the foundations of the forecasts and the potential risks associated with adopting a CCA strategy.

The purpose of this report is to set out a simple analytic model for examining the economics of CCA implementation (by California communities) that relies less heavily on uncertain forecasts of volatile market prices and optimistic power trading results. This is the third in a series of reports by the Bay Area Economic Forum dealing with economic issues surrounding the municipalization of electric power systems, and the seventh in a series focusing on power market issues in the wake of California's 2001 electricity crisis. **The focus of this report is on the issue of whether the implementation of CCAs in Northern California can be expected to reliably reduce electricity costs to local electricity consumers.** It sets out a simple model and shows broad non-numerical measures for comparing and benchmarking CCA power costs against those of an incumbent utility, and provides approximate numerical benchmarks for CCA generation costs that would equate Northern California CCA costs to PG&E's. It also summarizes generation cost estimates for traditional and emerging technologies that have been referenced as potential sources for CCA power supply in prior CCA feasibility studies, and relates those costs to the estimated benchmarks.

This report does not attempt to address political and environmental considerations associated with local control of power supply that may be accomplished through CCAs, except to the extent that generation choices based on environmental criteria have an effect on the cost of electricity. The focus on economics is critical because it is most likely that the economic viability of a CCA is a precondition to its ability to accomplish environmental and other goals. While communities have the option of subsidizing a CCA as a good cause even if the economics do not pan out, few communities appear to have excess funds to do so.

The first section of the report reviews the key elements of the CCA enabling legislation, CPUC implementation rules, tax laws and capital structure.

The next section develops a Comparative Cost Model. As was the case in the Forum's prior two reports on the economics of municipalization, the analytic framework employed is a comparative model of system average rates (SARs) based on the conventional cost-of-service equations for investor-owned utilities, and for public utilities. Simple algebraic manipulation of the cost-of-service equations provides insights on CCA/IOU relative power costs without reliance on uncertain electric rate or market price forecasts.

The third section applies estimates of PG&E retained generation production data and develops CCA production cost benchmarks for Northern California.

The fourth section utilizes California Energy Commission (CEC) power production analyses for various emerging technologies to examine generation plant development options for CCAs.

The fifth section summarizes results and offers some recommendations for CCA development strategies.

Background

Key Elements of AB117 and CPUC CCA Implementation Rules

As a precondition for establishing CCAs, AB 117 charged the California Public Utilities Commission (CPUC) with responsibility for establishing utility cost recovery mechanisms that avoid cost shifting to utility bundled customers when CCAs begin operation, for developing transition/customer transfer rules, and for reviewing and certifying CCA implementation plans proposed by local agencies. The CPUC held a sequence of two proceedings which resulted in Decision 04-12-046 (December

16, 2004) and Decision 05-12-041 (December 5, 2005). The first decision dealt with program implementation and transaction costs, ratemaking for utility services to CCAs, and the setting of Cost Responsibility Surcharges (CRS) to be collected from CCA served customers to cover Competitive Transition Costs, Department of Water Resources (DWR) Bond Charges, and the above-market portions of DWR and Qualifying Facility (QF) power contracts held by the electric utility. The second decision set rules for CCA transition and implementation, reentry/switching fees, CARE discounts, and vintaging of the CRS. Vintaging means that the CRS for each CCA will be revised according to utility above-market commitments that are in effect at the time the CCA is implemented.

Cost Responsibility Allocation

To prevent the shifting of utility cost obligations from CCA customers to bundled customers, the CPUC has established the CRS as a non-avoidable charge (currently set at 2 cents/KWh) that must be paid by all CCA customers on all electric usage. This charge is intended to cover all above-market costs that may have been incurred or committed to by the utility, for serving customers prior to the date that the departing customers are transferred to the CCA. These costs are imbedded in electric rates paid by bundled customers and charging the CRS to departing customers is intended to make the bundled customers indifferent about customers transferring to CCAs. The CPUC will periodically review and possibly modify the CRS as the configuration of utility cost obligations changes. While there is a general expectation that the CRS will diminish over time (as the DWR contracts expire), new “above market” obligations could be incurred by the utilities in meeting environmental requirements and/or other contingencies downstream. By vintaging the CRS, the CPUC left open the possibility for the CRS to change in both directions.

While above market power cost obligations are transferred to the customers of CCAs through the CRS, AB 117 and the CPUC CCA implementation rules do not provide for the transfer of credits for below market utility power supply to the customers of CCAs. In particular, the benefits of any utility owned low cost hydro and nuclear production are retained by the utility's bundled customers. To the extent that the utility retained generation production costs and/or some long-term power contract costs are below market prices, the departure of customers to CCAs will reduce the average power costs allocated to bundled service. This asymmetric allocation of power costs is a key aspect of the economics to be considered in evaluating the implementation of CCAs. The retention of the benefits of retained generation creates the potential for a utility cost advantage.

Consumer Participation Options

A fundamental consumer protection stipulation of the AB 117 enabling legislation is that every customer eligible to receive CCA electric supply services must also be given the opportunity to opt-out of the CCA Program and receive bundled electric services from the utility. While all customers in a CCA area will initially be automatically enrolled in the CCA when the program is certified and initiated, they will be given 60 days in which to opt-out without penalty, and resume service from the utility under the same terms that apply to customers who return to utility service from direct access services. Under those terms, the utility can charge the CCA reentry fees for resuming bundled service to opt-out customers (as specified on utility tariffs³). The CCA may also be entitled to impose opt-out charges on departing customers⁴. The consumer opt-out privileges create generic uncertainty in the CCA organizational structure and management that may impose significant

³ See PG&E Schedule E-CCA

⁴ Two CCA plans call for charging exit fees to customers who elect to opt-out after 60 days. See ***City of San Francisco Community Aggregation Plan***, Section 5.3.2.2, and San Joaquin Valley Power Authority, ***Community Aggregation Implementation Plan and Statement of Interest***, pages 62 & 63.

and unpredictable CCA costs and risks associated with load forecasting and developing contracts to initiate CCA service. The CCA must develop its supply plan, estimate revenue requirements, allocate revenue requirements by customer class, design rates, issue a binding notice of intent to serve customers in its jurisdiction, announce its rate proposal and terms of service to its prospective customers – all without knowing with certainty what customers it will serve.

The consumer opt-out privileges guaranteed by AB 117 also present a challenge to the planning and operation of CCAs since the CCA won't know with certainty what the scope and load profile of its customer base will be more than a month or so in advance. If the CCA enters long-term power supply contracts and/or builds generation plants, it faces the risk of stranded assets (power supply that can not be sold for its purchase cost) when customers depart back to the utility. If instead, it makes extensive use of spot market purchases to avoid stranded assets, the CCA will be exposed to market price risk. While some of the market risk might be hedged, hedging will increase the costs of service. The bottom line is that uncertainty about the size and composition of the customer base is generic to the structure of CCAs and will most likely result in inefficiencies and higher costs⁵.

Some prior studies have made relatively sanguine assumptions about the proportion of customers who may opt-out of California CCA programs, but have not provided evidence to support these assumptions or provided analysis of the implications of differing opt-out rates⁶. However, one study reported scenarios with differing opt-out rates and found that the opting out of large customers led to

⁵ Uncertainty of customer base has been a major argument of IOU's in connection with direct access, and was the motivation for the requirement that customers returning to bundled service from direct access service must continue bundled service for at least 3 years.

⁶ For example, Navigant assumed 100% participation in its "Base Case Feasibility Evaluation – Marin County", March 2005, and suggested a simple adjustment could be made for other opt-out rates.

projections of poor performance by CCAs relative to PG&E's rates⁷. In light of the importance of large commercial and industrial customers to the potential success of CCAs, it appears to be a significant analytic omission that none of the studies have reported the results of surveys or analyses about the attitudes of large businesses concerning the CCA/IOU cost differential thresholds that they would tolerate before opting out. Many large customers are energy intensive, compete in global markets, must operate as efficiently as possible, and may have little flexibility for supporting the aims of CCAs if a CCA cost advantage does not materialize or cannot be sustained.⁸

The significance of large commercial and industrial customer participation in the CCA is amplified by the requirements of AB1X. AB1X specifies that IOU rates for residential electricity usage up to 130% of the baseline threshold are set at 2001 levels. By many estimates these frozen rates are well below current and projected market prices for power. Assuming that to be true, the first 130% of baseline usage must be subsidized by higher usage residential customers and non-residential customers. AB1X does not directly apply to CCAs. However, if CCAs choose to offer service to residential customers, the CCA will have to offer residential rates that are essentially capped by the IOU's (AB1X compliant) residential rate. This in turn may require a high level of CCA participation by non-residential customers to cover the subsidies so long as AB1X is in effect⁹.

IOU/CCA Relative Taxation and Capital Structure

⁷ Altos concluded that, "Virtually all of the cases we examined that posited significant opt-out by CCSF's larger commercial and industrial electricity customers resulted in unfavorable outcomes for the CCA." **Community Choice Aggregation Draft Implementation Plan**, Chapter 4, page 7. However, Altos noted reductions in PG&E's rates due to CCA Customers opting out rather than increases in CCA rates due to uncertainty of the customer base.

⁸ The consumer opt-out privileges could conceivably be the Achilles Heel of AB 117. Should CCA rates drift higher than IOU rates and several large customers return to IOU bundled service leaving stranded generation, CCA rates would have to rise which could prompt more customers to also opt-out, setting off a death spiral of rising rates and departing customers.

⁹ AB1X is currently expected to be in effect until 2022, **AB1X Reinterpretation by CPUC**, news article on SDG&E web site.

Public entities, including CCAs, are exempt from paying federal and state income taxes as well as local property taxes and franchise fees. The exemption from income taxes is an advantage for CCAs, but reductions in property taxes and franchise fees paid to local government that are avoided through the formation of CCAs must be made up from the local citizens through other taxes if government is to be made whole. Alternatively, it is reasonable to assume for analytic purposes that the CCA will continue to pay local property taxes and franchise fees.

When it comes to the development of owned generation plants, CCAs will have a distinct cost advantage. While IOUs use a combination of debt and equity to finance assets, municipal utilities (including CCAs) use only debt. Also, for developing CCA owned generation, CCAs can likely use tax free bonds¹⁰. This implies the CCA will have a lower capital cost per dollar of generation in rate base than will an IOU owning the same generation plant. It also implies that CCAs can best exploit their tax advantage by owning high capital cost, low operating cost generation facilities such as geothermal, wind and solar.

Comparative Cost and Benchmark Models

The purpose of the comparative cost model below is to develop some general insights about the comparative generation costs of CCAs and IOUs, and to develop generation cost benchmarks for Northern California CCAs competing with PG&E's generation costs. The methodology used in the model is presented in the form of equations; for the general reader its conclusions are highlighted in bold. A glossary of terms is contained in Appendix I.

The model is developed from the conventional cost –of-service equation that is a simple accounting method that tallies up the costs that comprise a utility's System Average Rate or SAR. The SAR is the broadest measure of consumer electricity

¹⁰ There are many restrictions on how tax free bonds are used. For example, they can not be used to buy out the assets of an existing utility.

costs¹¹. From an historical perspective, the SAR is the total electric revenue that an electric utility collects from its customers, divided by the total volume of electricity delivered to its customers (in megawatt-hours or MWh). From a forward looking perspective, the numerator for calculating the SAR is the total revenue required for the utility to cover its projected costs, and the denominator is a projection of electricity sales.

The foundation for the comparative cost model is the conventional cost-of-service equation that equates SAR to the sum of the utility's component costs (operating expense, depreciation, taxes and capital costs, plus other charges set by the CPUC for public purpose programs, nuclear decommissioning, competitive transition charges, DWR bond charges, reliability services, and energy cost recovery) expressed as costs per MWh. These component costs can be disaggregated and rearranged into detailed costs by function (e.g. power production, transmission, distribution, and customer service). Since CCA implementation only involves the takeover of the IOU's power supply function, the IOU side of the comparative model need only include the generation or power supply component of the IOU SAR – the generation average rate or GAR_{IOU} ¹². The GAR_{IOU} is the total cost of the electricity generated divided by the total megawatt hours of electricity supply (or total generation). This denominator differs from the denominator for the SAR by an adjustment for transmission and distribution losses. Since losses are not a factor in the cost comparisons between CCAs and IOUs, it is more convenient to set the GARs up in terms of total megawatt hours of generation rather than total megawatt hours of sales.

By setting the analysis up in terms of average rates rather than total dollar expenditures, the comparisons developed can apply across utilities and CCAs.

¹¹ The SAR is an average rate across all customer classes, each of which may pay a differing rate. While CCA and PG&E rates may be designed to give preference to one rate class or another, the best rate concept for evaluating CCA economic viability is the SAR.

¹² See **City of San Francisco Community Aggregation Plan**, Figure 1, for a visual version of the cost-of-service equations for IOUs and CCAs.

The GAR_{IOU} is the volume-weighted average cost of power, including utility retained generation and power purchases:

$$GAR_{IOU} = SR_{IOU} * CR_{IOU} + SP_{IOU} * CP_{IOU} \quad \text{EQ1}$$

Where,

CR_{IOU} = average unit cost of power from utility owned (retained)

SR_{IOU} = retained generation share of total supply

CP_{IOU} = average unit cost of power purchased by the utility,

SP_{IOU} = IOU purchased power share of total supply, where

$$SP_{IOU} + SR_{IOU} = 1$$

The asterisk (*) is used as the symbol for multiplication

The two terms of EQ1 are simply the cost contributions of retained generation and of power purchases to the average cost of the IOU power supply.

For example, if an IOU generates 60% of its power supply at an average cost of \$45 per MWh, and purchases 40% from the wholesale market at \$60 per MWh, then

$$GAR_{IOU} = .6 * 45 + .4 * 60 = \$51$$

Utilities have sometimes entered into long-term contracts that later turned out to be more expensive than the power that the utility could buy in the wholesale market.

An example would be the DWR contracts that were entered into by the State during California's power crisis and later assigned to California utilities. This being the case, if we look at the cost of the entire supply of power purchased for a utility, on average it will probably cost more than it could bought for in the current wholesale market. For analysis, it is useful to decompose those costs per MWh into the wholesale market price (MP) and an over market premium (PM).

Estimating the decomposition of DWR and QF contract prices into market and over-market components has been a major task for the CPUC in attempting to determine what the CRS should be.

Substituting $MP + PM$ for CP_{IOU} (or replacing CP_{IOU} with $MP + PM$) the equation EQ1 can be written as follows:

$$GAR_{IOU} = SR_{IOU} * CR_{IOU} + SP_{IOU} * MP + SP_{IOU} * PM \quad \text{EQ2}$$

This equation simply says that the IOU average generation cost is a weighted average of retained generation costs, purchased power valued at market, and purchased power valued at the over market premium. **EQ2 is the IOU Cost Model.**

The GAR_{CCA} is the volume weighted average cost of power including CCA owned generation and power purchases plus the CRS, and the CCA Overhead costs per MWh (OV_{CCA}) as follows:

$$GAR_{CCA} = SO_{CCA} * CO_{CCA} + SP_{CCA} * CP_{CCA} + CRS + OV_{CCA} \quad \text{EQ3}$$

Where,

CO_{CCA} = average unit cost of power from CCA owned generation

SO_{CCA} = owned generation share of total CCA supply

CP_{CCA} = average unit cost of power purchased by the CCA

SP_{CCA} = CCA purchased power share of total supply, where

$$SP_{CCA} + SO_{CCA} = 1$$

OV_{CCA} = CCA overhead costs per MWh

The OV_{CCA} variable is intended to cover all CCA administrative and operating costs (including power trading profits and losses, ISO charges, and utility charges to the CCA per PG&E Schedule E-CCA) and interest payments on investment required to set up the CCA, exclusive of any owned power plant costs. This overhead charge per MWh can be expected to vary in proportion to the level of the market trading activity, gains and losses from trading, and utility charges (per schedule E-CCA) related to the consumer opt-out rate. **EQ3 is the CCA Cost Model.**

The cost per MWh differential between CCAs and IOUs is the difference in GARs, $GAR_{CCA} - GAR_{IOU} =$,

$$SO_{CCA} * CO_{CCA} + SP_{CCA} * CP_{CCA} + CRS + OV_{CCA} - (SR_{IOU} * CR_{IOU} + SP_{IOU} * MP + SP_{IOU} * PM) \quad \text{EQ4}$$

This expression can be simplified using the observation that **any new CCA will acquire incremental power in the same competitive wholesale market as will the IOU and both will pay the market price (MP)¹³**.

$$CP_{CCA} = MP \quad \text{EQ5}$$

Note that the IOU will continue to be burdened with the overhang of old over-market contracts and will also pay the average premium (PM) for its purchased power.

However, as specified in CPUC Decision 04-12-046 and Decision 05-12-041, the CPUC attempts to set the CRS to cover the over-market costs of utility power purchases which implies that, on average,

$$CRS = SP_{IOU} * PM^{14} \quad \text{EQ6}$$

Substituting EQ5 and EQ6 into EQ4, the CRS is eliminated from the equation and the cost differential can be simplified as follows¹⁵:

$$\begin{aligned} GAR_{CCA} - GAR_{IOU} &= \\ &SO_{CCA} * CO_{CCA} + SP_{CCA} * MP + OV_{CCA} - (SR_{IOU} * CR_{IOU} + SP_{IOU} * MP) \\ &\text{On rearranging terms,} \\ GAR_{CCA} - GAR_{IOU} &= \\ &SO_{CCA} * CO_{CCA} - SR_{IOU} * CR_{IOU} + (SP_{CCA} - SP_{IOU}) * MP + OV_{CCA} \quad \text{EQ7} \end{aligned}$$

¹³ It could be argued that it is possible for a CCA or PG&E to outperform the other in electricity trading. While both face the same prices, one could conceivably do better in the mix of spot, medium term and long-term contracts, and in the size of blocks purchased. However, to count on such an outcome is speculative.

¹⁴ Note that the CRS is the charge per MWh for all consumption, while the over market premium is charged only to the power purchases portion of the utility's power supply. The product $SP_{IOU} * PM$ translates the total value of over market expenditures to a per MWh basis spread across all consumption.

¹⁵ Navigant has claimed, "Once the CRS terminates at some point in the future, the Aggregator will compete against PG&E's then current supply portfolio, and PG&E will no longer have the protection afforded by the CRS", **Base Case Feasibility Evaluation-Marin County**, March 2005 page 25. As shown by EQ7, the CPUC policy of setting the CRS to prevent cost shifting renders the CRS irrelevant to the CCA/ IOU cost comparison. When the CRS declines, the costs of bundled service will diminish in a similar proportion and neither the CCA nor the IOU should gain any cost advantage.

EQ7 is the Comparative Cost Model.

This Model can be used to calculate rate differentials and it can also be used to develop some general insights about comparative costs without the use of specific data. For example, If the CCA purchases all of its power supply in the competitive market (as would likely be the case during the first three to five years of CCA operation), ($SO_{CCA} = 0$ and $SP_{CCA} = 1$), and substituting the identity $SR_{IOU} = 1 - SP_{IOU}$ into EQ7 yields,

$$GAR_{CCA} - GAR_{IOU} = SR_{IOU} * (MP - CR_{IOU}) + OV_{CCA} \quad \text{EQ8}$$

If a utility operates any retained generation, then it can be assumed that the cost of that generation is below the market price for generation (otherwise the utility would buy its power from the market). That being the case, EQ8 implies the common sense observation that **if the incumbent utility operates any retained generation and the CCA purchases 100% of its power supply from the competitive market, the CCA cannot avoid higher average rates than the utility unless it subsidizes rates (or somehow wins the gamble of “beating the market”)**.

For example, if the incumbent utility generates 60% of its power supply from retained generation at a cost of \$45 per MWh, the market price is \$60 per MWh, and the CCA overhead is \$5 per MWh then,

$$GAR_{CCA} - GAR_{IOU} = .6 * (60 - 45) + 5 = 9 + 5 = \$14 \text{ per MWh}$$

In other words, for this example, the CCA power cost will be \$14 per MWh higher than the IOU power cost, an excess that cannot be overcome with power purchases alone.

It should also be noted that the only term of EQ8 that can be even partially controlled by the CCA is its overhead (OV_{CCA}) and, its overhead cost can be

affected by the customer opt-out rate. In other words, the CCA's cost differential will be determined virtually independent of any actions that the CCA might take, so long as the CCA is dependent only on market purchases for its supply.

It is apparent from this equation that **for a CCA to have any potential of matching or beating the power supply costs of the incumbent utility, the CCA must exploit its tax advantage by building, owning and operating efficient generating plants.** If it does build, own and operate new plants then what must the average production costs of those plants be in order to match the incumbent IOU's average power production costs? The Comparative Cost Model can be rearranged to calculate cost benchmarks for the CCA by simply setting EQ7 to 0 and solving for the CCA average owned production cost (CO_{CCA}).

This exercise yields the following:

$$CO_{CCA} = [SR_{IOU} * CR_{IOU} + (SP_{IOU} - SP_{CCA}) * MP - OV_{CCA}] / SO_{CCA} \quad \text{EQ9}$$

EQ9 is the Benchmark Model. The model specifies the target maximum (or benchmark) average cost for CCA-owned power production that will allow the CCA to match the IOU's generation average rates. The equation implies that the benchmark is determined by the IOU's average cost of retained generation, the difference in the IOU vs. CCA shares of power purchased in the market, and CCA's overhead. The higher the IOU's cost of retained generation, the higher the IOU's market purchases relative to the CCA's market purchases; and the higher the market price, the higher (or less challenging) will be the CCA's target generation cost. Also, the higher the CCA's overhead and the lower the CCA's portion of owned generation, the lower (and more challenging) will be the CCA target generation cost.

Note that if the utility operates some retained generation, and the CCA also builds owned generation to cover the same percent of load as the IOU's retained generation (for example, if both generate 30% and purchase 70% of their total

supply), then the market price falls out of Benchmark Model, which provides a useful benchmark insight. More precisely, if

$$SP_{CCA} = SP_{IOU} \quad \text{EQ10}$$

and

$$SO_{CCA} = SR_{IOU} \quad \text{EQ11}$$

then the substitution of EQ10 and EQ11 into EQ9 and re-arrangement yields the following simplified benchmark equation.

$$CO_{CCA} = CR_{IOU} - OV_{CCA} / SO_{CCA} \quad \text{EQ12}$$

This equation implies that **if a CCA develops its owned generation plant (utilizing its tax and financing advantage) sufficient to cover the same share of total power supply as the IOU's share of retained generation, the CCA must match the IOU's average cost of retained generation less the CCA's average cost of overhead divided by the IOU's share of retained generation. This benchmark holds regardless what the market price might be.**

For a numerical illustration, if the incumbent utility generates 60% of its power supply from retained generation at a cost of \$45 per MWh, and the CCA overhead is \$5 per MWh, then the CCA's target would be,

$$CO_{CCA} = 45 - 5 / .6 = 45 - 8.33 = \$36.67$$

The simple algebraic operations with the cost-of-service equations that have been performed above, demonstrate that **the economic viability of a new CCA depends primarily on the potential for the CCA to develop efficient owned generating capacity. Until such time as a CCA can utilize its tax advantage by developing and bringing on-line generating resources that meet or exceed the cost benchmark criteria of EQ9, the CCA will have to collect higher rates from its customers (than the utility rates) or finance subsidies. This suggests that the first stage of CCA feasibility studies should be focused on**

precisely how, where and when the prospective CCA can site, build, and operate efficient generating facilities, and precisely what the operating characteristics and generation costs of those specific plants will likely be.

In spite of the critical importance of plant-specific operational and cost data to the economic viability of CCAs, such data is conspicuously absent from most of the CCA plans being proposed to Northern California communities¹⁶. Unless the proposed CCA can verify that the operating characteristics are consistent with the load requirements of the community and that the costs of specific plant technologies built out at specific sites meet or exceed the appropriate benchmarks against the incumbent IOU's costs, the community will lack the economic information it needs to decide whether to invest in the CCA or for consumers to consider opting in¹⁷.

From a long-term perspective, to the extent that the CCA is able to develop owned sources of renewable power, and secure a higher proportion of its energy supply from renewable power than renewables secured by the utility, it may be able to reduce its exposure to the political and market risk associated with hydrocarbon fuels, yielding unspecified cost advantages. Though speculative, other benefits may accrue if in the future the federal government were to implement a carbon tax.

¹⁶ The San Joaquin Plan appears to be the exception, having identified a specific plant location and technology and is preparing to file with the CEC Siting Division for a license to build. The San Francisco Plan refers to a "360 MW Roll Out" consisting of conservation, fuel cells, solar and wind generation but provides no data concerning how or where any specific plants will be sited or what their production levels or costs will be. The Navigant Marin County Report lists a portfolio of plant technologies and cost figures for wind, geothermal, gas, absent specifics on how or where the plants would be sited.

¹⁷ The need for site specific plant information was provided by the CEC in its frequently quoted report on generic plant costs as follows: "This Report is intended to provide a basic understanding of some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources. But these costs do not reflect the total costs to consumers of adding these technologies to a resource portfolio. The technology costs in this report are non site-specific. If a developer builds a specific plant at a specific location, the cost of siting that plant at that specific location must be considered. Some projects may require radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses" **Comparative Cost of California Central Station Electricity Generating Technologies**, CEC, June 5 2003.

The comparative cost and benchmarking discussion in this section has focused on general cost relationships that can be extracted from conventional cost-of-service equations. The following section develops numerical estimates of PG&E's retained generation average rates and uses those estimates with the Benchmark Model to develop numerical benchmarks for prospective Northern California CCAs.

Northern California CCA Cost Benchmarks Against PG&E Retained Generation Costs

Proposed CCAs for Northern California communities would take over the power supply function of Pacific Gas and Electric Company within the community's boundaries. Therefore, PG&E's retained generation¹⁸ costs are a key factor in determining the cost thresholds that the CCA must meet to be economically viable. This section describes PG&E's retained generation capacity for nuclear, hydro, and steam plant types, presents estimates of numerical generation costs for each plant type and for the average across all plants, and develops numerical average production cost benchmarks for CCA owned generation that would be required for matching PG&E's generation rates.

PG&E's 2006 FERC Form 1 Annual Report shows that the utility's retained generation accounted for 36% of the utility's total power supply. The composition of the retained generation was approximately 20% nuclear, 15.5 % hydro, and .5% gas fired steam¹⁹ To develop numerical benchmarks for CCA production costs, forecasts of PG&E's nuclear, hydro and steam production costs are required.

¹⁸ Retained generation refers to the fleet of power plants that were not sold by PG&E during the period of electric industry restructuring that required plant divestiture by investor owned utilities.

¹⁹ 2006 FERC Form 1, page 401a

Nuclear Production Cost

In 2006, Diablo Canyon produced 18,390,997 MWh of electricity, running at a capacity factor of 93%. Having very low operating cost, and a nearly depreciated rate base, Diablo Canyon has been producing very low-cost power. However, PG&E has now scheduled the replacement of its generators in 2008 and 2009 at a cost of about \$706 million. This will substantially increase the rate base, depreciation expense, capital cost and tax allocations for Diablo Canyon production. While Diablo Canyon costs will be increasing, the CPUC has approved the generation replacement project (Decision 05-11-026) agreeing that it is a low cost alternative for future power supply.

To develop a nuclear production cost projection, it was assumed that Diablo Canyon will generally operate at a capacity factor of 89% (consistent with performance in recent years), adjusted downward for outages during the periods of generator replacement and periods of refueling. Cost projections were developed using data from PG&E's FERC Form 1, and various PG&E documents filed with the CPUC in connection with the generation replacement project, from PG&E's 2007 General Rate Case documents, and from work papers obtained from PG&E. Projections of PG&E's nuclear production costs are shown in Appendix II (Table 1).

Hydro Production Cost

In 2006, PG&E's conventional hydro generators produced 14,186,653 MWh. Hydro has been a major source of inexpensive power for PG&E for many years but levels of production vary somewhat with weather conditions. During the past ten years, hydro facilities have produced an average of 12,014,457 MWh per year. This average was used to develop a forecast of hydro generation cost. Cost estimates have been developed from PG&E's FERC Form 1 and 2007 General Rate Case documents and from work papers obtained from PG&E. Projections of PG&E's hydro production costs are shown in Appendix II (Table 1).

Steam Production Cost

In 2006, PG&E generated only about one half percent of its power supply from aging gas fired plants, including Hunters Point, which was permanently shut down in May 2006. Looking forward, PG&E will have minimal gas-fired generation until its new Gateway Generating Station (formerly Contra Costa Unit 8 that PG&E took over during construction from Mirant) is brought on line in mid-to-late 2009. This unit is an efficient 530 MW combined cycle plant. For cost analysis, it is assumed that the unit will begin operation in 2010, will operate with a heat rate of 7,100 btu's per KWh, a capacity factor of 91.6%, and produce 4,252,806 MWh per year. No other future additions to PG&E's fleet of generating units have been assumed. Cost projections for this plant have been developed using data derived from various CEC staff reports and from CPUC documents related to Application 05-06-029. Projections of PG&E's steam production costs are shown in Appendix II (Table 1).

Generation Average Cost

The average production cost for PG&E's retained generation $CR_{PG\&E}$ is the volume- weighted average of the average production costs for the three plant types. Projections of $CR_{PG\&E}$ are shown in Appendix II (Table 1) for 2007 through 2024.

CCA Owned Generation Benchmarks

The projections of $CR_{PG\&E}$ can be used as an input to the Benchmark Model to calculate the maximum CCA-owned generation cost that would yield average rates that match PG&E's. The Model with $SR_{IOU} = SR_{PG\&E}$ and $CR_{IOU} = CR_{PG\&E}$ and $SP_{PG\&E} = 1 - SR_{PG\&E}$ inserted is as follows:

$$CO_{CCA} = [SR_{PG\&E} * CR_{PG\&E} + (SP_{PG\&E} - SP_{CCA}) * MP - OV_{CCA}] / SO_{CCA} \quad \text{EQ9}$$

The Model was used with varying assumptions about the market price MP (from 1.1 to 1.5 times PG&E's average production cost), the CCA's overhead OV_{CCA} (\$4 to \$8 per MWh), and the CCA share of load generated by owned production units (from 10 % to 100%). The results are shown in Appendix II (Tables 2 through 7).

The first column shows years 2007 through 2024. The second column shows PG&E's average production cost from Table 1. The third column is the assumed wholesale market price for power. Each of Tables 2 through 6 use different assumptions about the market price relative to PG&E's average rate (10 – 50% higher). The data in the remaining 11 columns across each page beginning with column 4 are the benchmark average cost figures that the CCA must not exceed in order to match or beat PG&E's rates. The column labeled **EQ PG&E %** shows benchmarks that are independent of market prices. This column shows the maximum average cost of CCA-owned generation if the CCA matched PG&E's generation as a percent of total load. Since both the CCA and utility purchase the same share in the market, the market price does not affect the benchmark.

It has been established algebraically above, that **a new CCA cannot compete with the incumbent utility by buying all of its power in a competitive wholesale market, if the incumbent operates owned generating plants. The tables show that the higher the market price, the less stringent are the production cost requirements for the CCA.** The tables also show that the greater the percent of load that the CCA can produce, the higher is the maximum production cost for competing. For example, Table 6 shows that for 2010, with PG&E's cost at \$46.77 and the market price at \$70.16, the CCA would have to produce power at an average cost of \$29.95 per MWh if it produces only 30% of its load (and takes 70% from the market) but would only have to reach an average cost of \$57.98 if it produced 100% of its load. The tables also show the competitive implications of the CCA's overhead. For example, compare the 2010 rows on Tables 6 and 7 to see the substantial effect of changing CCA overhead from \$4 to \$8 per MWh. The impact of overhead is the greatest for lower percentages of load covered by production. At 30% owned generation with overhead at \$8, the benchmark for competitive production cost drops all the way from \$29.54 to \$16.21.

As shown by EQ9, the competitive position of the CCA is to a large extent affected by forces outside its control - the market and the incumbent utility. The only variables in the model that the CCA can affect are its overhead and its choice of owned production. The benchmarks shown on these tables provide some thresholds for CCAs to use in targeting generation plant development. **The real issue for CCAs is to develop generation plant that will give them a sustainable cost advantage.**

CCA Generation Potential

Unless communities are willing to gamble on the notion that new CCAs can “beat the market” effectively and consistently enough to compete with PG&E, then the focus of CCA planning should be on precisely what plant technologies to build and precisely where to build them. The most likely cost advantage of a CCA is in using its financing advantage by building high capital cost, low operating cost generating plants. The technology that best fills that bill is renewable geothermal which is included in the proposed resource portfolio of the Marin County Feasibility Study²⁰. However, it is not clear where a Northern California community can find geothermal fields with adequate pressure for power generation and be able to obtain the rights for development. The only apparent sites in Northern California are near the Geysers and near the Oregon border. With the completion of the Bottle Rock facility the remaining potential close to the Bay Area will be very limited. And, given the attractiveness of geothermal in meeting requirements for renewable resources there will likely be significant competition for any feasible sites, diminishing the prospects for obtaining competitive power costs from this resource.

²⁰ The Marin report list 29 MW of geothermal at a levelized cost of \$55/MWh.(in 2005 \$).

The next best technology for CCA's appears to be wind, as has been recognized in prior studies. The cost estimates for green field or generic wind generators appear to be in the ballpark of numbers that could be competitive (Navigant reported \$49/MWh plus \$11/MWh for backup capacity), particularly if gas prices remain high. However, where a CCA can get rights and authorization to site wind generators, and what the site specific costs will be must also be addressed.

The production costs of several emerging technologies have been studied by the California Energy Commission. However, the CEC's production cost estimates for such technologies as solar PV and fuel cells (that have been included in the San Francisco Plan), were at that time far too high to be, considered competitive resources. These technologies will likely become more efficient over time but it has not been demonstrated that they have reached a competitive stage.

Conclusions

Communities considering CCAs must consider two elements of their resource portfolios: supply secured through the market, and owned generation capacity. Regarding market trading, they need to ask whether they can outperform the IOU. Regarding owned generation, to be competitive they must develop renewable or other capacity at the necessary scale.

The analyses in this report point to two key conclusions. First, if the incumbent utility owns and operates generation plants, then a new CCA cannot reliably compete on average rates while purchasing all of its power supply in the competitive wholesale market. And, second, the CCA's ability to compete rests with its success in using its tax advantage in financing, developing, owning and operating efficient, high capital-intensive generating plants.

Though more expensive in the short-term, generation from renewable sources may offer the advantage of hedging the long-term price and supply risk associated with fossil energy. The limited availability of renewable generation at scale, and the fact

that much of that capacity will be heavily competed for by IOUs and other utilities that are also seeking to expand their renewable energy portfolios, suggests that securing these resources may not be easy.

The implication is that communities considering CCAs should first develop detailed resource plans that specify the types and sizes of generating plants that will be developed to serve the community's load, where they will be sited, and what the site-specific installed production costs will be. Once a competitive resource plan (one that meets or beats the benchmark tests of EQ9) has been developed, the community can make an informed decision on whether to proceed with the establishment of a CCA and make the investment needed to acquire the necessary generation capacity.

For those communities that decide to proceed with the formation of a CCAs, the first order of business should be to commit to the necessary siting decisions and expeditiously develop those generating facilities. To avoid unnecessary subsidies by taxpayers, the transfer of customers from the incumbent utility should take place after competitive generating plants are in operation.

APPENDICES

Glossary of Terms

Abbreviations:

AB	Assembly Bill
CCA	Community Choice Aggregator – a local government agency
CEC	California Energy Commission
CPUC	California Public Utilities Commission
IOU	Investor owned utility
DWR	California Department of Water Resources
QF	Qualifying Facility

Model Variables and Symbols

CO_{CCA}	Average cost per MWh of power from CCA owned generation
CP_{CCA}	Average cost per MWh of power purchased by the CCA
CP_{IOU}	Average cost per MWh of power purchased by the IOU
CR_{IOU}	Average cost per MWh of power from IOU retained generation
CRS	Cost Responsibility Surcharge
GAR_{CCA}	CCA Generation Average Rate
GAR_{IOU}	IOU Generation Average Rate
MP	Market Price
OV_{CCA}	CCA overhead costs per MWh
PM	Premium
SAR	Utility System Average Rate
SO_{CCA}	Owned generation share of total CCA power supply
SP_{CCA}	CCA purchased power share of total CCA power supply
SP_{IOU}	IOU purchased power share of total IOU power supply
SR_{IOU}	IOU retained generation share of IOU power total supply
*	Symbol representing multiplication

TABLE 1 PG&E GENERATION AVERAGE RATES (\$/MWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015
NUCLEAR GENERATION:									
AVERAGE RATE	38.77	48.78	58.01	54.29	54.02	54.12	54.35	59.54	54.84
SHARE OF TOTAL SUPPLY (%)	19.07	17.74	16.23	18.24	17.97	17.71	17.44	16.22	16.93
HYDRO GENERATION:									
AVERAGE RATE	30.04	30.98	31.92	32.84	33.73	34.61	35.46	36.30	37.12
SHARE OF TOTAL SUPPLY	13.01	12.81	12.62	12.44	12.25	12.07	11.89	11.72	11.55
STEAM GENERATION:									
AVERAGE RATE	0.00	0.00	0.00	55.13	55.60	56.10	56.61	57.16	57.73
SHARE OF TOTAL SUPPLY	0.00	0.00	0.00	4.33	4.26	4.20	4.14	4.08	4.02
WEIGHTED AVERAGE COST OF GENERATION (GAR_{PG&E}):									
AVERAGE COST PER MWH	35.23	41.31	43.43	46.77	47.00	47.43	47.92	50.73	48.90
GENERATION SHARE OF LOAD	32.08	30.55	30.95	35.00	34.49	33.98	33.48	32.02	32.49
	2016	2017	2018	2019	2020	2021	2022	2023	2024
NUCLEAR GENERATION:									
AVERAGE RATE	54.06	53.93	53.74	58.91	54.20	53.10	52.79	56.76	50.94
SHARE OF TOTAL SUPPLY	16.68	16.44	16.19	15.06	15.72	15.48	15.26	14.02	14.81
HYDRO GENERATION:									
AVERAGE RATE	37.92	38.70	39.47	40.22	40.95	41.66	42.64	43.03	43.68
SHARE OF TOTAL SUPPLY	11.38	11.21	11.04	10.88	10.72	10.56	10.40	10.25	10.10
STEAM GENERATION:									
AVERAGE RATE	58.32	58.94	59.59	60.27	60.98	61.72	62.49	63.28	64.12
SHARE OF TOTAL SUPPLY	3.96	3.90	3.84	3.78	3.73	3.67	3.62	3.56	3.51
WEIGHTED AVERAGE COST OF GENERATION (GAR_{PG&E}):									
AVERAGE COST PER MWH	48.85	49.14	49.39	52.24	50.33	50.10	50.38	52.54	49.99
RETAINED GEN SHARE OF LOAD	32.01	31.54	31.07	29.72	30.16	29.72	29.28	27.83	28.42

TABLE 2
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS (\$/MWh)
MARKET PRICE 10% HIGHER THAN PG&E AVERAGE PRODUCTION COST
CCA OVERHEAD \$4/MWh

MARKET = 1.5*CRPGE, OVH 4	PG&E AVG COST	MARKET PRICE	CCA % OF LOAD FROM OWNED GENERATION										
			EQ PG&E %	10	20	30	40	50	60	70	80	90	100
2007	35.23	38.75	22.76	-12.55	13.10	21.65	25.93	28.49	30.20	31.42	32.34	33.05	33.62
2008	41.31	45.45	28.22	-7.18	19.14	27.91	32.29	34.92	36.68	37.93	38.87	39.60	40.18
2009	43.43	47.77	30.51	-5.67	21.05	29.96	34.41	37.08	38.87	40.14	41.09	41.83	42.43
2010	46.77	51.45	35.35	-4.92	23.27	32.66	37.36	40.18	42.06	43.40	44.41	45.19	45.82
2011	47.00	51.71	35.41	-4.51	23.60	32.97	37.65	40.46	42.34	43.68	44.68	45.46	46.08
2012	47.43	52.17	35.66	-3.94	24.12	33.47	38.15	40.95	42.82	44.16	45.16	45.94	46.56
2013	47.92	52.71	35.97	-3.33	24.69	34.03	38.70	41.50	43.37	44.70	45.70	46.48	47.10
2014	50.73	55.80	38.24	-0.44	27.68	37.06	41.74	44.56	46.43	47.77	48.77	49.55	50.18
2015	48.90	53.79	36.59	-2.10	25.84	35.16	39.82	42.61	44.47	45.80	46.80	47.58	48.20
2016	48.85	53.74	36.36	-1.90	25.92	35.19	39.83	42.61	44.46	45.79	46.78	47.55	48.17
2017	49.14	54.05	36.46	-1.44	26.31	35.55	40.18	42.95	44.80	46.13	47.12	47.89	48.50
2018	49.39	54.33	36.52	-1.02	26.66	35.88	40.49	43.26	45.11	46.42	47.41	48.18	48.80
2019	52.24	57.47	38.78	1.94	29.70	38.96	43.58	46.36	48.21	49.53	50.53	51.30	51.91
2020	50.33	55.36	37.07	0.18	27.77	36.97	41.56	44.32	46.16	47.48	48.46	49.23	49.84
2021	50.10	55.11	36.64	0.22	27.66	36.81	41.39	44.13	45.96	47.27	48.25	49.01	49.62
2022	50.38	55.42	36.72	0.67	28.04	37.17	41.73	44.47	46.29	47.60	48.57	49.33	49.94
2023	52.54	57.79	38.17	3.17	30.48	39.59	44.14	46.87	48.69	49.99	50.97	51.73	52.33
2024	49.99	54.99	35.92	0.78	27.89	36.92	41.44	44.15	45.96	47.25	48.21	48.97	49.57

TABLE 3
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS (\$/MWh)
MARKET PRICE 20% HIGHER THAN PG&E AVERAGE PRODUCTION COST
CCA OVERHEAD \$4/MWh

MARKET = 1.5*CRPG E, OVH 4	PG&E AVG COST	MARKET PRICE	CCA % OF LOAD FROM OWNED GENERATION										
			EQ PG&E %	10	20	30	40	50	60	70	80	90	100
2007	35.23	42.28	22.76	-20.33	10.97	21.41	26.62	29.75	31.84	33.33	34.45	35.32	36.01
2008	41.31	49.58	28.22	-15.67	16.96	27.83	33.27	36.53	38.70	40.26	41.42	42.33	43.05
2009	43.43	52.12	30.51	-14.77	18.67	29.82	35.39	38.74	40.97	42.56	43.75	44.68	45.43
2010	46.77	56.13	35.35	-16.62	19.76	31.88	37.94	41.58	44.01	45.74	47.04	48.05	48.86
2011	47.00	56.41	35.41	-16.02	20.20	32.27	38.30	41.92	44.34	46.06	47.35	48.36	49.16
2012	47.43	56.92	35.66	-15.31	20.80	32.84	38.86	42.47	44.88	46.60	47.89	48.89	49.69
2013	47.92	57.50	35.97	-14.58	21.46	33.47	39.48	43.08	45.49	47.20	48.49	49.49	50.29
2014	50.73	60.88	38.24	-11.61	24.64	36.72	42.76	46.38	48.80	50.52	51.82	52.82	53.63
2015	48.90	58.68	36.59	-13.10	22.79	34.75	40.73	44.32	46.72	48.42	49.71	50.70	51.50
2016	48.85	58.62	36.36	-12.66	22.98	34.86	40.80	44.37	46.74	48.44	49.71	50.70	51.49
2017	49.14	58.97	36.46	-12.03	23.47	35.30	41.22	44.77	47.14	48.83	50.09	51.08	51.87
2018	49.39	59.27	36.52	-11.43	23.92	35.71	41.60	45.13	47.49	49.17	50.43	51.42	52.20
2019	52.24	62.69	38.78	-8.36	27.17	39.01	44.93	48.48	50.85	52.54	53.81	54.80	55.59
2020	50.33	60.39	37.07	-9.97	25.21	36.94	42.80	46.32	48.67	50.34	51.60	52.57	53.36
2021	50.10	60.12	36.64	-9.66	25.23	36.86	42.67	46.16	48.49	50.15	51.40	52.37	53.14
2022	50.38	60.46	36.72	-9.04	25.71	37.29	43.08	46.56	48.87	50.53	51.77	52.73	53.51
2023	52.54	63.05	38.17	-6.20	28.43	39.97	45.74	49.20	51.51	53.16	54.39	55.36	56.12
2024	49.99	59.99	35.92	-8.42	25.78	37.18	42.89	46.31	48.59	50.22	51.44	52.39	53.15

TABLE 4
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS (\$/MWh)
MARKET PRICE 30% HIGHER THAN PG&E AVERAGE PRODUCTION COST
CCA OVERHEAD \$4/MWh

MARKET = 1.5*CRPGE , OVH 4	PG&E AVG COST	MARKET PRICE	CCA % OF LOAD FROM OWNED GENERATION										
			EQ PG&E %	10	20	30	40	50	60	70	80	90	100
2007	35.23	45.80	22.76	-28.11	8.85	21.16	27.32	31.02	33.48	35.24	36.56	37.59	38.41
2008	41.31	53.71	28.22	-24.16	14.78	27.75	34.24	38.14	40.73	42.59	43.98	45.06	45.92
2009	43.43	56.46	30.51	-23.87	16.29	29.68	36.38	40.39	43.07	44.98	46.42	47.53	48.43
2010	46.77	60.81	35.35	-28.31	16.25	31.10	38.53	42.98	45.95	48.08	49.67	50.91	51.90
2011	47.00	61.11	35.41	-27.53	16.79	31.56	38.95	43.38	46.33	48.44	50.03	51.26	52.24
2012	47.43	61.66	35.66	-26.69	17.49	32.21	39.57	43.99	46.94	49.04	50.62	51.84	52.83
2013	47.92	62.29	35.97	-25.83	18.23	32.92	40.26	44.67	47.60	49.70	51.28	52.50	53.48
2014	50.73	65.95	38.24	-22.77	21.59	36.38	43.77	48.21	51.16	53.28	54.86	56.09	57.08
2015	48.90	63.57	36.59	-24.10	19.74	34.35	41.65	46.03	48.96	51.04	52.61	53.83	54.80
2016	48.85	63.51	36.36	-23.41	20.05	34.54	41.78	46.12	49.02	51.09	52.64	53.85	54.82
2017	49.14	63.88	36.46	-22.61	20.63	35.05	42.26	46.58	49.47	51.53	53.07	54.27	55.23
2018	49.39	64.21	36.52	-21.83	21.19	35.53	42.70	47.00	49.87	51.92	53.45	54.65	55.61
2019	52.24	67.91	38.78	-18.66	24.63	39.06	46.27	50.60	53.49	55.55	57.09	58.30	59.26
2020	50.33	65.42	37.07	-20.11	22.66	36.91	44.04	48.32	51.17	53.20	54.73	55.92	56.87
2021	50.10	65.13	36.64	-19.53	22.80	36.91	43.96	48.20	51.02	53.03	54.55	55.72	56.66
2022	50.38	65.49	36.72	-18.76	23.37	37.41	44.43	48.64	51.45	53.46	54.96	56.13	57.07
2023	52.54	68.30	38.17	-15.57	26.37	40.35	47.34	51.53	54.33	56.32	57.82	58.98	59.92
2024	49.99	64.99	35.92	-17.63	23.68	37.45	44.33	48.46	51.22	53.18	54.66	55.81	56.73

TABLE 5
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS (\$/MWh)
MARKET PRICE 40% HIGHER THAN PG&E AVERAGE PRODUCTION COST
CCA OVERHEAD \$4/MWh

MARKET = 1.5*CRPGE , OVH 4	PG&E AVG COST	MARKET PRICE	CCA % OF LOAD FROM OWNED GENERATION										
			EQ PG&E %	10	20	30	40	50	60	70	80	90	100
2007	35.23	49.32	22.76	-35.89	6.72	20.92	28.02	32.28	35.12	37.15	38.67	39.85	40.80
2008	41.31	57.84	28.22	-32.65	12.60	27.68	35.22	39.74	42.76	44.91	46.53	47.79	48.79
2009	43.43	60.80	30.51	-32.97	13.92	29.54	37.36	42.05	45.17	47.41	49.08	50.38	51.42
2010	46.77	65.48	35.35	-40.01	12.74	30.32	39.11	44.39	47.90	50.41	52.30	53.76	54.94
2011	47.00	65.81	35.41	-39.04	13.39	30.86	39.60	44.84	48.33	50.83	52.70	54.16	55.32
2012	47.43	66.40	35.66	-38.06	14.17	31.58	40.29	45.51	48.99	51.48	53.35	54.80	55.96
2013	47.92	67.08	35.97	-37.08	15.00	32.36	41.04	46.25	49.72	52.20	54.06	55.51	56.67
2014	50.73	71.02	38.24	-33.94	18.54	36.03	44.78	50.03	53.53	56.03	57.90	59.36	60.53
2015	48.90	68.46	36.59	-35.10	16.68	33.94	42.57	47.75	51.20	53.66	55.51	56.95	58.10
2016	48.85	68.39	36.36	-34.16	17.11	34.21	42.75	47.88	51.30	53.74	55.57	57.00	58.14
2017	49.14	68.80	36.46	-33.20	17.80	34.80	43.30	48.40	51.80	54.23	56.05	57.46	58.60
2018	49.39	69.15	36.52	-32.24	18.45	35.35	43.80	48.87	52.25	54.66	56.48	57.88	59.01
2019	52.24	73.14	38.78	-28.96	22.09	39.10	47.61	52.72	56.12	58.55	60.38	61.79	62.93
2020	50.33	70.46	37.07	-30.26	20.10	36.88	45.28	50.31	53.67	56.07	57.87	59.27	60.39
2021	50.10	70.14	36.64	-29.41	20.36	36.95	45.25	50.23	53.55	55.92	57.69	59.08	60.18
2022	50.38	70.53	36.72	-28.47	21.03	37.53	45.78	50.73	54.03	56.39	58.16	59.53	60.63
2023	52.54	73.56	38.17	-24.93	24.31	40.73	48.93	53.86	57.14	59.49	61.25	62.61	63.71
2024	49.99	69.99	35.92	-26.84	21.57	37.71	45.78	50.62	53.85	56.15	57.88	59.23	60.30

TABLE 6
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS (\$/MWh)
MARKET PRICE 50% HIGHER THAN PG&E AVERAGE PRODUCTION COST
CCA OVERHEAD \$4/MWh

MARKET = 1.5*CRPGE , OVH 4	PG&E AVG COST	MARKET PRICE	CCA % OF LOAD FROM OWNED GENERATION										
			EQ PG&E %	10	20	30	40	50	60	70	80	90	100
2007	35.23	52.84	22.76	-43.66	4.59	20.67	28.72	33.54	36.76	39.06	40.78	42.12	43.19
2008	41.31	61.97	28.22	-41.14	10.42	27.60	36.19	41.35	44.79	47.24	49.08	50.52	51.66
2009	43.43	65.14	30.51	-42.07	11.54	29.41	38.34	43.70	47.28	49.83	51.74	53.23	54.42
2010	46.77	70.16	35.35	-51.70	9.23	29.54	39.70	45.79	49.85	52.75	54.93	56.62	57.98
2011	47.00	70.51	35.41	-50.55	9.98	30.16	40.24	46.30	50.33	53.21	55.38	57.06	58.40
2012	47.43	71.15	35.66	-49.43	10.86	30.95	41.00	47.03	51.05	53.92	56.07	57.75	59.09
2013	47.92	71.87	35.97	-48.33	11.77	31.81	41.82	47.83	51.84	54.70	56.85	58.52	59.85
2014	50.73	76.10	38.24	-45.11	15.49	35.69	45.79	51.85	55.89	58.78	60.95	62.63	63.98
2015	48.90	73.35	36.59	-46.10	13.63	33.53	43.49	49.46	53.44	56.28	58.42	60.08	61.40
2016	48.85	73.28	36.36	-44.92	14.18	33.88	43.73	49.64	53.58	56.39	58.50	60.14	61.46
2017	49.14	73.71	36.46	-43.78	14.96	34.55	44.34	50.21	54.13	56.93	59.02	60.66	61.96
2018	49.39	74.09	36.52	-42.65	15.72	35.18	44.90	50.74	54.63	57.41	59.50	61.12	62.41
2019	52.24	78.36	38.78	-39.26	19.55	39.15	48.96	54.84	58.76	61.56	63.66	65.29	66.60
2020	50.33	75.49	37.07	-40.41	17.54	36.86	46.52	52.31	56.17	58.93	61.00	62.61	63.90
2021	50.10	75.15	36.64	-39.29	17.93	37.00	46.54	52.26	56.08	58.80	60.84	62.43	63.70
2022	50.38	75.57	36.72	-38.18	18.69	37.65	47.13	52.82	56.61	59.32	61.35	62.93	64.19
2023	52.54	78.81	38.17	-34.30	22.25	41.11	50.53	56.19	59.96	62.65	64.67	66.24	67.50
2024	49.99	74.99	35.92	-36.05	19.47	37.98	47.23	52.78	56.48	59.12	61.11	62.65	63.88

TABLE 7
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS (\$/MWh)
MARKET PRICE 50% HIGHER THAN PG&E AVERAGE PRODUCTION COST
CCA OVERHEAD \$8/MWh

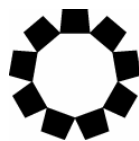
MARKET = 1.5*CRPGE , OVH 4	PG&E AVG COST	MARKET PRICE	CCA % OF LOAD FROM OWNED GENERATION										
			EQ PG&E %	10	20	30	40	50	60	70	80	90	100
2007	35.23	52.84	10.29	-83.66	-15.41	7.34	18.72	25.54	30.09	33.34	35.78	37.68	39.19
2008	41.31	61.97	15.13	-81.14	-9.58	14.27	26.19	33.35	38.12	41.53	44.08	46.07	47.66
2009	43.43	65.14	17.58	-82.07	-8.46	16.07	28.34	35.70	40.61	44.11	46.74	48.79	50.42
2010	46.77	70.16	23.92	-91.70	-10.77	16.21	29.70	37.79	43.18	47.04	49.93	52.18	53.98
2011	47.00	70.51	23.81	-90.55	-10.02	16.82	30.24	38.30	43.67	47.50	50.38	52.61	54.40
2012	47.43	71.15	23.89	-89.43	-9.14	17.62	31.00	39.03	44.38	48.21	51.07	53.30	55.09
2013	47.92	71.87	24.02	-88.33	-8.23	18.47	31.82	39.83	45.17	48.99	51.85	54.07	55.85
2014	50.73	76.10	25.74	-85.11	-4.51	22.36	35.79	43.85	49.23	53.07	55.95	58.18	59.98
2015	48.90	73.35	24.28	-86.10	-6.37	20.20	33.49	41.46	46.77	50.57	53.42	55.63	57.40
2016	48.85	73.28	23.86	-84.92	-5.82	20.55	33.73	41.64	46.91	50.68	53.50	55.70	57.46
2017	49.14	73.71	23.78	-83.78	-5.04	21.21	34.34	42.21	47.46	51.21	54.02	56.21	57.96
2018	49.39	74.09	23.65	-82.65	-4.28	21.84	34.90	42.74	47.97	51.70	54.50	56.67	58.41
2019	52.24	78.36	25.32	-79.26	-0.45	25.82	38.96	46.84	52.09	55.84	58.66	60.85	62.60
2020	50.33	75.49	23.80	-80.41	-2.46	23.52	36.52	44.31	49.51	53.22	56.00	58.17	59.90
2021	50.10	75.15	23.18	-79.29	-2.07	23.67	36.54	44.26	49.41	53.09	55.84	57.99	59.70
2022	50.38	75.57	23.05	-78.18	-1.31	24.32	37.13	44.82	49.94	53.60	56.35	58.49	60.19
2023	52.54	78.81	23.80	-74.30	2.25	27.77	40.53	48.19	53.29	56.94	59.67	61.80	63.50
2024	49.99	74.99	21.84	-76.05	-0.53	24.64	37.23	44.78	49.81	53.41	56.11	58.20	59.88



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