

**Case 7: PG&E Generation Rates Increase At An Annual Rate Of 3% Vs. 1.7%  
Of The Base Case (Millions of Dollars)**

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	149.7	163.7	14.1	5%
2007	150.4	170.9	20.5	7%
2008	159.2	178.4	19.2	7%
2009	153.8	186.2	32.4	11%
2010	163.9	194.3	30.5	10%
2011	169.5	202.8	33.4	11%
2012	174.3	211.7	37.5	12%
2013	163.7	221.1	57.4	18%
2014	167.8	230.8	62.9	20%
2015	177.7	240.9	63.3	19%
2016	181.3	251.5	70.2	21%
2017	188.3	262.6	74.4	21%
2018	198.6	274.2	75.6	20%
2019	208.4	286.3	77.9	20%
2020	222.6	299.0	76.3	19%
2021	225.6	312.2	86.6	21%
2022	230.1	326.0	95.9	23%
2023	227.7	329.2	101.5	23%
2024	239.1	344.1	105.0	23%
Total	3,551.7	4,686.0	1,134.4	17%

\* For comparison, total savings under the base case is \$340.5 million or 5%.

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

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	149.6	150.1	0.5	0%
2007	150.4	152.6	2.3	1%
2008	160.5	158.3	(2.1)	-1%
2009	153.7	162.2	8.5	3%
2010	163.8	170.4	6.7	2%
2011	169.4	175.8	6.5	2%
2012	174.2	181.8	7.6	2%
2013	163.5	172.5	9.0	3%
2014	167.6	177.4	9.8	3%
2015	177.4	183.7	6.2	2%
2016	181.1	188.1	7.0	2%
2017	188.0	197.5	9.5	3%
2018	198.3	211.9	13.5	4%
2019	208.2	225.0	16.8	4%
2020	222.4	232.4	10.0	2%
2021	225.3	234.4	9.1	2%
2022	229.8	239.7	9.9	2%
2023	227.3	240.2	12.8	3%
2024	238.7	254.6	15.9	4%
Total	3,548.9	3,708.5	159.6	2%

\* For comparison, total savings under the base case is \$340.5 million or 5%. PG&E's rate proposals would increase residential rates and reduce commercial and industrial rates, which would have the effect of reducing the PG&E costs paid by bundled service customers within the City.

## **7 EVALUATION OF COSTS AND BENEFITS**

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

### **7.1 Ability To Deliver Lower Rates**

The economic analysis demonstrates that it is feasible for the City to implement a CCA program. Customers would be able to obtain electric service at rates below those charged by PG&E. Under the most likely scenario, expected savings average 5% of total electric bills over the study period.

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

### **7.2 Rate Stability**

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

The sensitivity analysis shows an expected range of program savings of between 2% and 17% over the study period. The City's portfolio would demonstrate relatively stable prices to consumers. Under the base case scenario, which reflects very conservative assumptions regarding future increases in PG&E's rates, the CCA program costs are expected to show 13% greater stability than PG&E's rates.

### **7.3 Increased Utilization Of Renewable Energy**

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

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

### 7.3.1 Cost Of Renewable Energy

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

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

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

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

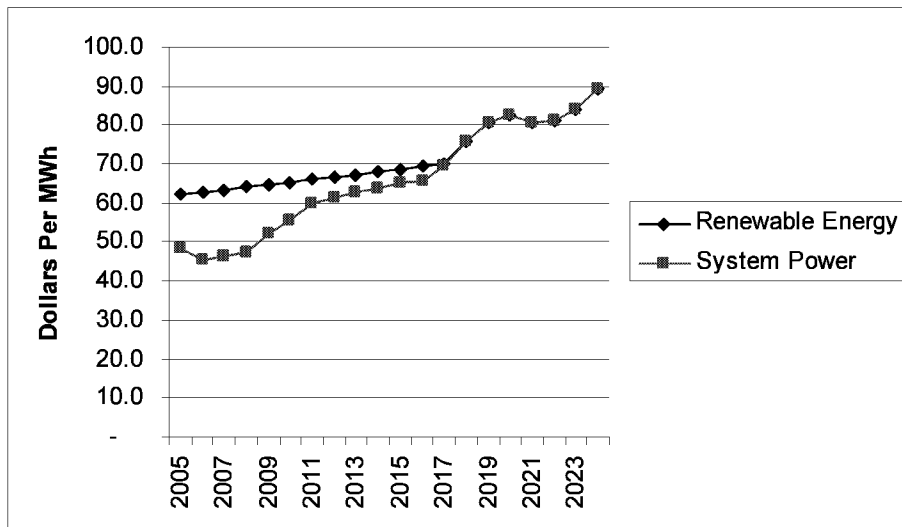
Escalating the cost to 2006 by assuming 2.5% annual inflation yields a 2006 average renewable cost of \$62 per MWh. This represents a premium of approximately \$18 per MWh above the projected market prices of system power in 2006.

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

\$2.52 per MWh. A typical household would pay \$1.26 more per month to double the amount of renewable energy used to supply its electricity consumption.<sup>27</sup> The premium declines over time as natural gas and electricity market prices are expected to rise faster than the cost of renewable energy production. For instance, assuming average annual increases in the market price of system power of 2.8% used in this study, the renewable price premium falls to \$4 per MWh by 2014. By 2018, the market price of renewable energy is expected to be no greater than the cost of conventional generation resources.<sup>28</sup>

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

### Northern California Market Price Projections For Renewable And Conventional Electricity



### 7.3.2 Municipal Financing of Renewable Energy Development

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

<sup>27</sup> Typical residential consumption is approximately 500 kWh or 0.5 MWh per month.

<sup>28</sup> The cost of transmission investments that may be needed to bring large amounts of renewable energy to load centers is not included in this analysis. These costs will be included in transmission rates that are paid by all users of the grid and should not impact the CCA economic analysis.

underlying assumptions are that the utility’s capital structure is comprised of 50% debt and 50% equity at an overall cost of capital of 9%, while the City employs 100% debt financing at a rate of 5.5%. The utility is subject to federal and state income taxes of 40.75% so that the tax-effected cost of capital is 12.9%. The City makes no return, has no income tax obligation and establishes its revenue requirement based on the cash requirements needed to cover expenses and debt service.<sup>29</sup>

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

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

The capital-related costs are significantly less if the City were to own or otherwise finance the resource, compared to ownership by an investor owned utility such as PG&E. The costs of maintaining and operating the resource would be the same, as would be the cost of capacity needed to “firm” the wind resource’s intermittent production. The use of low cost debt and greater financial leverage by the City reduces the annualized costs. During the first year of operation, the City can produce energy at a cost that is nearly 40% lower than what the investor owned utility would incur if it owned the identical resource. The City’s cost of producing renewable energy would be nearly the same as the market price of system power.

**7.3.3 Operational Issues For Renewable Energy**

Renewable resources are generally non-dispatchable, operating as either baseload resources or on an as-available basis. Wind and solar resources produce electricity only during certain times of the day when there is sufficient wind or sun. These characteristics place an operational limit on the amount of renewable energy that can be included in the overall resource mix. Depending on a community’s load duration curve, which defines its base load requirements,

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<sup>29</sup> Section 8.1.6 discusses financing options available to the City’s CCA program.

the operational limit could range between 50% and 70%.<sup>30</sup> It would be possible to exceed these amounts by over-procuring, but doing so would require the Aggregator to sell excess energy into the market during many hours of the year, thereby taking on additional risks associated with wholesale sales of energy.

A similar issue exists with reliance on intermittent wind production. If an Aggregator with an average load requirement of 200 MW established a 50% renewable target, it would need approximately 300 MW of wind capacity. With a typical capacity factor of 32%, production from 300 MW of wind capacity would average the 100 MW needed to meet the target. However, at any moment in time, the Aggregator could have between 0 and 300 MW of production. The Aggregator would either need to purchase 200 MW of replacement energy or it would have 100 MW excess energy to sell. These imbalances impose financial risk on the Aggregator as the prices at which it must buy and sell energy may not be identical.<sup>31</sup>

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

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<sup>30</sup> This refers only to the City's program operations and is not intended to imply that the entire system could efficiently integrate such large amounts of renewable energy.

<sup>31</sup> Firming services are available via contract with energy suppliers, typically those with significant hydroelectric resources in their portfolio.



