This Chapter examines the monthly cash flows expected during the implementation period of the CCA Program and identifies the anticipated financing requirements for the overall CCA Program by MCE. It includes estimates of program startup costs, including the necessary staffing and capital outlays which would commence once the CPUC accepts the Implementation Plan submitted by MCE. It also describes the requirements for working capital and long term financing for the investment in renewable generation, consistent with the resource plan contained in Chapter 3.

The cash flow analysis is indicative of program financials assuming MCE could procure full requirements electric supply for approximately 8.8 cents per kWh. The analysis should be updated with the pricing data provided in response to a future request for information/request for proposals process.

Description of Cash Flow Analysis

This cash flow analysis estimates the level of working capital that would be required until full implementation of the CCA program is achieved. For the purposes of this analysis, it is assumed that the implementation period begins in January 2010 and continues through December 2013. In general, the components of the cash flow analysis can be summarized into two distinct categories: (1) Cost of CCA Program Operations, and (2) Revenues from CCA Program Operations. The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with the CCA Program implementation period, and specifically account for the transition or "Phase-In" of CCA Customers from PG&E's service territory described in Chapter 3.

Cost of CCA Program Operations

The first category of the cash flow analysis is the Cost of CCA Program Operations. To estimate the overall costs associated with CCA Program Operations, the following components were taken into consideration:

- Electricity Procurement;
- Ancillary Service Requirements;
- Exit Fees;
- Staffing Requirements;
- Contractor Costs;
- Infrastructure Requirements;
- Billing Costs;
- Scheduling Coordination;
- Grid Management Charges; and
- Franchise Fees.

A key element of the cash flow analysis is the assumption that electricity will be procured exclusively under a power purchase arrangement until the proposed renewable resource would be operational. After that time, supply cost reductions are expected as MCE's resource displaces power purchases. The focus of this cash flow analysis is during the implementation period when opportunities for supply cost savings are more limited.

The assumed cost of third party electric supply used in this analysis, excluding the cost of MCE's operations and contractor costs, is 8.8 cents per KWh. This price represents the price needed for a full requirements electricity contract during the implementation period to allow the rates and program revenue surpluses presented below. As mentioned previously, the cash flow analysis will be updated following receipt of pricing offers from potential third party electric suppliers.

Revenues from CCA Program Operations

The cash flow analysis also provides estimates for revenues generated from CCA operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes the customer phase-in schedule noted above, and assumes that MCE's CCA provides a Light Green Tariff at comparable generation rates to those of the existing distribution utility for each customer class and a 100 percent Green Tariff at a premium reflective of incremental renewable power costs. Based on this assumed rate structure, the following tables provide a comparison of the projected distribution utility rate and MCE's electric rates (in each of the two proposed tariffs: 100 percent Green and Light Green) over the CCA program implementation period.

Marin Clean Energy

Comparison of Electric Rates – MCE versus distribution utility

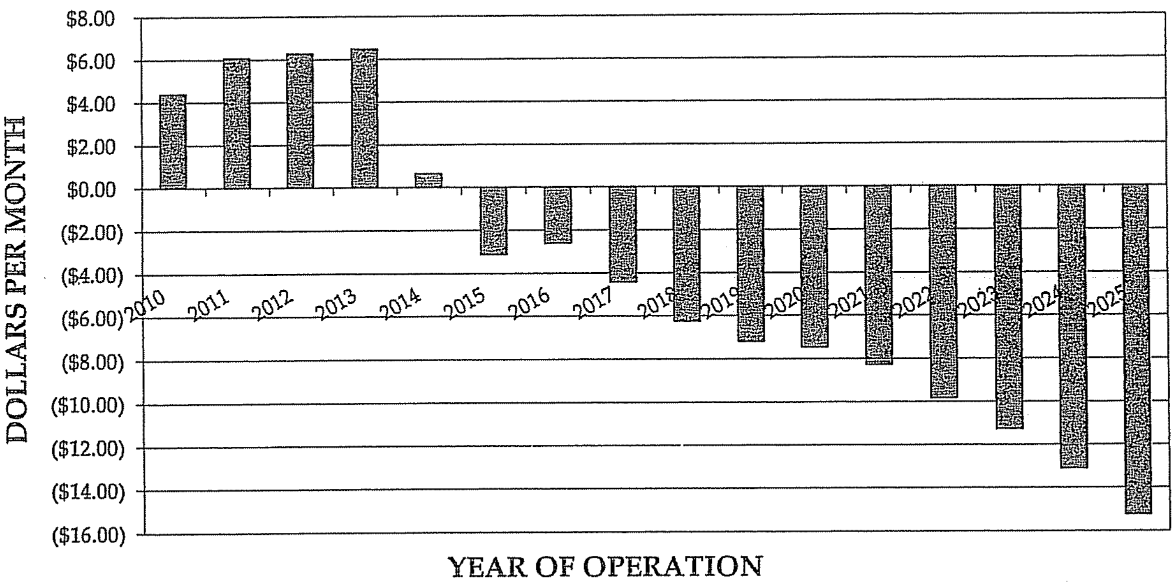
CATEGORY	2010	2011	2012	2013
MCE's Electric Rate ($/MWh)--100% Renewable	$112.34	$110.81	$114.75	$118.77
IOU Electric Rate ($/MWh)	$93.61	$92.34	$95.63	$98.97
Variance ($/MWh)	($18.72)	($18.47)	($19.13)	($19.79)
Variance in Generation Rate (%)	-20.0%	-20.0%	-20.0%	-20.0%
Impact to Monthly Residential Customer Bill (%)	-10.3%	-10.2%	-10.4%	-10.5%

CATEGORY	2010	2011	2012	2013
MCE's Electric Rate ($/MWh)--25/51% Renewable	$93.61	$92.34	$95.63	$98.97
IOU Electric Rate ($/MWh)	$93.61	$92.34	$95.63	$98.97
Variance ($/MWh)	$0.00	$0.00	$0.00	$0.00
Variance in Generation Rate (%)	0.0%	0.0%	0.0%	0.0%
Impact to Monthly Residential Customer Bill (%)	0.0%	0.0%	0.0%	0.0%

As previously noted, MCE would develop or otherwise obtain entitlements to up to 200 MW of new renewable generation by 2014. The power produced by this new renewable generating capacity would be delivered to MCE at production costs, which are significantly lower than retail prices charged by energy suppliers participating in the market. Over time, MCE's preference for renewable energy will significantly reduce its exposure to volatile input costs (fuel – natural gas) associated with natural gas-fired generation, which are expected to increase steadily, and potentially significantly, for the foreseeable future. Because over 80 percent of MCE's power supply (beginning in 2014) will be from renewable energy sources, upward price pressures on its power supply should be significantly reduced over long-term operations. The following chart depicts the projected trend in average monthly price premiums paid by an average customer of MCE.[27]

[27] An "average" customer was determined based on participation levels in both the 100 percent Green Tariff and Light Green Tariff for all customer classes. The projected impacts to monthly bills of an average customer reflect these participation levels and represent the net effects of Light Green Tariff participants, who will pay no premium, and customers participating in the 100 percent Green Tariff, who will pay a higher premium than that which is displayed in the chart.

MARIN CLEAN ENERGY
AVERAGE PROGRAM PREMIUM (MONTHLY)
CUSTOMER USING 500KWh/MONTH



These long-term cost savings, which can be identified in the chart as negative premiums, could be passed on to program customers in the form of lower generation rates or could be applied to the procurement of additional renewable energy supplies (moving the program's renewable energy supply closer to its 100 percent goal), energy efficiency programs or other energy/climate initiatives within the scope of broad-based powers established for MCE. Ultimately, MCE would have flexibility when making these decisions and could respond to the evolving needs of local residents and businesses when developing rate tariffs and energy/climate-focused programs.

Cash Flow Analysis Results

The results of the cash flow analysis provide an estimate of the level of working capital required for MCE to move through the CCA implementation period. This estimated level of working capital is determined by examining the monthly cumulative net cash flows (revenues from CCA operations minus cost of CCA operations) based on assumptions for payment of costs by MCE, along with an assumption for when customer payments will be received. This identifies, on a monthly basis, what level of cash flow is available in terms of a surplus or deficit. With regard to the assumptions related to payments streams, the cash flow analysis assumes that customers will make payments within 60 days of the service month, and that MCE will make payments to suppliers within 30 days of the service month. This likely overstates the net payment lag to some extent because customer payments begin to come in soon after the bill is issued, and most are received before the due date. At the same time, some customer payments are received well after the due date. The 30 day net lag is a conservative assumption for cash flow purposes.

With the assumptions regarding payment streams, the cash flow analysis itself identifies funding requirements while recognizing the potential lag between payments received and payments made during the implementation period. The estimated financing requirements for the implementation period (2010 – 2013), including working capital, based on the phase-in of customers as described above is approximately $15.8 million. Working capital requirements reach this peak immediately after enrollment of the Phase 3 customers.

CCA Program Implementation Feasibility Analysis

In addition to developing a cash flow analysis which estimates the level of working capital required to get MCE through full CCA implementation, a summary analysis that evaluates the feasibility of the CCA program during the implementation period has been prepared. The difference between the cash flow analysis and the CCA feasibility analysis is that the feasibility analysis does not include a lag associated with payment streams. In essence, costs and revenues are reflected in the month in which service is provided. All other items, such as costs associated with CCA Program operations and rates charged to customers remain the same.

The results of the feasibility analysis, based on the power supply cost figure discussed above, are shown in the following table. Under these assumptions, over the entire implementation period the CCA program is projected to accrue a reserve account balance of approximately $18 million. Power supply costs below approximately 8.8 cents per kWh for the four-year startup period would enable the program to at least match PG&E's rates for customers subscribing to the Light Green Tariff. Conversely, power supply costs above this figure would jeopardize the program's potential to offer Light Green Tariff rates that are equivalent to PG&E during this time period, because CCA rates would be higher than those charged by PG&E.

Marin Clean Energy
Summary of CCA Program Implementation
(January 2009 through December 2013)

CATEGORY	2009	2010	2011	2012	2013	TOTAL
I. REVENUES FROM OPERATIONS ($):						
(A) ELECTRICITY SALES:						
RESIDENTIAL	$0	$271	$68,459,083	$71,209,427	$74,070,266	$213,739,048
GENERAL SERVICE (A-1)	$0	$332,029	$16,246,125	$16,911,607	$17,591,030	$51,080,791
SMALL TIME-OF-USE (A-6)	$0	$277,770	$5,769,373	$6,067,692	$6,311,462	$18,426,297
ALTERN. RATE FOR MEDIUM USE (A-10)	$0	$15,499,512	$21,734,676	$22,664,751	$23,575,307	$83,474,246
500 - 900kW DEMAND (E-19)	$0	$6,597,654	$9,049,315	$9,375,412	$9,752,069	$34,774,451
1000 + kW DEMAND (E-20)	$0	$3,904,820	$5,405,411	$5,633,713	$5,860,048	$20,803,993
STREET LIGHTING & TRAFFIC CONTROL	$0	$534,302	$755,054	$785,389	$816,942	$2,891,687
AGRICULTURAL PUMPING	$0	$275	$549,460	$548,644	$570,686	$1,669,065
TOTAL REVENUES	$0	$27,146,633	$127,968,499	$133,196,635	$138,547,810	$426,859,577
II. COST OF OPERATIONS ($):						
(A) ADMINISTRATIVE & GENERAL (A&G):						
STAFFING	$451,067	$2,661,067	$3,092,725	$3,185,507	$3,281,072	$12,671,437
INFRASTRUCTURE	$139,500	$192,000	$157,500	$162,225	$167,092	$818,317
CONTRACTOR COSTS	$434,833	$1,607,417	$2,608,875	$2,635,255	$2,714,313	$10,000,693
IOU FEES (INLCUDING BILLING)	$200,023	$187,286	$1,128,200	$1,024,786	$1,055,529	$3,595,825
CONTRACT STAFF	$0	$0	$0	$0	$0	$0
SUBTOTAL - A&G	$1,225,423	$4,647,770	$6,987,300	$7,007,773	$7,218,006	$27,086,271
(B) CCA PROGRAM OPERATIONS:						
ELECTRICITY PROCUREMENT	$0	$22,781,412	$107,727,159	$110,974,279	$114,317,379	$355,800,229
RENEWABLE PORTFOLIO ADJUSTMENT	$0	$1,422,695	$9,284,041	$8,400,441	$7,507,772	$26,614,948
SUBTOTAL - CCA PROGRAM OPERATONS	$0	$24,204,106	$117,011,200	$119,374,720	$121,825,152	$382,415,177
TOTAL COST OF OPERATION	$1,225,423	$28,851,876	$123,998,499	$126,382,492	$129,043,157	$409,501,448
CCA PROGRAM SURPLUS / (DEFICIT)	($1,225,423)	($1,705,243)	$3,969,999	$6,814,143	$9,504,653	$17,358,129

The surpluses achieved during the implementation period serve as operating reserves for Marin Clean Energy in the event that operating costs (such as power purchase costs) exceed collected revenues for short periods of time. The following table provides an annual summary of the incremental costs incurred by program customers participating in the 100 percent Green Tariff during the implementation period. The incremental revenues would be used for paying the additional costs associated with the 100 percent renewable energy product. The premiums are projected to decline once the benefits of MCE's renewable resources begin to be realized and as costs for fossil fuels increase.

MARIN CLEAN ENERGY
COMMUNITY CHOICE AGGREGATION PROGRAM IMPLEMENTATION
SUMMARY OF COSTS INCURRED FOR 100% GREEN ENERGY PREMIUM
(2010 THROUGH 2013)

CUSTOMER CLASS	2010	2011	2012	2013	TOTAL
RESIDENTIAL	$33	$8,407,256	$8,745,017	$9,096,348	$26,248,655
GENERAL SERVICE (A-1)	$40,775	$1,995,138	$2,076,864	$2,160,302	$6,273,080
SMALL TIME-OF-USE (A-6)	$34,112	$708,520	$745,155	$775,092	$2,262,879
ALTERN. RATE FOR MEDIUM USE (A-10)	$1,903,449	$2,669,171	$2,783,390	$2,895,213	$10,251,223
500 - 900kW DEMAND (E-19)	$65,323	$89,597	$92,826	$96,555	$344,301
1000 + kW DEMAND (E-20)	$38,662	$53,519	$55,779	$58,020	$205,980
STREET LIGHTING & TRAFFIC CONTROL	$65,616	$92,726	$96,451	$100,326	$355,119
AGRICULTURAL PUMPING	$11	$21,133	$21,102	$21,949	$64,195
TOTAL	$2,147,981	$14,037,059	$14,616,585	$15,203,806	$46,005,432

Capital Requirements

The start-up of the CCA Program will require a significant amount of capital for three major functions: (1) staffing and contractor costs; (2) program initiation; and (3) working capital. Each of these anticipated requirements is discussed below.

Staffing costs for the initial twelve-month startup period (June 2009 through May 2010) are estimated to be approximately $1.4 million. Actual costs may vary depending on the ability of MCE to recruit qualified staff to fill the roles illustrated above. Contractor costs for the same time period are estimated to be approximately $1.3 million. These costs include: advertising/communications, consulting, legal, and data management.

Program initiation costs include the infrastructure that MCE will require (office space, utilities, computers) as well as the distribution utility fees for initiating the CCA Program. Infrastructure costs are estimated to be approximately $240,000 and the distribution utility fees are estimated to be approximately $368,000.

Therefore, the total staffing, contractor and program initiation costs are expected to be approximately $3.4 million. These are costs that ultimately will be collected through CCA Program rates; however, most of these costs will be incurred prior to MCE selling its first kWh of electricity. In addition, it is anticipated that additional working capital will be required to purchase electricity for Program customers prior to revenue being collected from those customers. During the start-up period (Phases 1 and 2), the total financing requirement is estimated to be approximately $6.4 million, increasing to approximately $15.8 million following enrollment of Phase 3 customers. MCE's plans for financing these capital requirements are discussed later in this chapter.

Startup Activities and Costs
The initial startup funding estimate of $3.4 million is budgeted to fund the following activities and costs:

- Define and execute communications plan:
    - Media campaign
    - Informational materials and customer notices
    - Customer call center
- Hire/contract for Executive Director, Sales and Marketing representatives, and Finance staff;
- Negotiate supplier/vendor contracts:
    - Electric supplier
    - Data management provider
- Pay utility service initiation, notification and switching fees;
- Perform customer notification, opt-out and transfers;
- Conduct load forecasting;
- Finalize rates;
- Legal and regulatory support;
- Financial reporting; and
- General consulting costs.

Other costs related to starting up the program will be the responsibility of the Program's contractors. These include capital requirements needed for collateral/credit support for electric supply expenses, customer information system costs, electronic data exchange system costs, call center costs, and billing administration/settlements systems costs.

Startup Cost Summary
Monthly costs associated with program startup and phasing of customer enrollments, which are estimated at approximately $3.4 million, include expenditures for program staff/contract staff, associated infrastructure, contractor costs and fees payable to the distribution utilities for CCA implementation and transactions costs. The estimated startup costs include capital expenditures and one-time expenses as well as ongoing expenses that will be accrued before significant revenues from program operations commence. These costs have been characterized as startup costs for purposes of the financing plan.

Start-up Costs	Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1	Phase 1 Operations	Notification and Enrollment Period		Cutover 2
Staffing	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
FTEs	4	4	4	4	4	5	9	9	14.5	18.5	20.5	20.5
Cost	$ 53,196	$ 53,196	$ 53,196	$ 53,196	$ 53,196	$ 70,338	$ 114,750	$ 114,750	$ 180,200	$ 218,379	$ 238,638	$ 238,638
Infrastructure												
Cost	$ 12,000	$ -	$ -	$ 73,125	$ 13,125	$ 16,125	$ 25,125	$ 13,125	$ 29,625	$ 25,125	$ 19,125	$ 13,125
Contractor Costs												
Advertising/Comm.	$ -	$ -	$ -	$ -	$ -	$ 20,000	$ 20,000	$ 10,000	$ 20,000	$ 50,000	$ 50,000	$ 10,000
Consulting	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417
Legal	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667
Data Management	$ -	$ -	$ -	$ -	$ -	$ 16,792	$ 16,792	$ 25,188	$ 25,188	$ 142,729	$ 142,729	$ 142,729
Subtotal Contractor Costs	$ 51,417	$ 51,417	$ 51,417	$ 51,417	$ 51,417	$ 88,875	$ 88,875	$ 87,271	$ 97,271	$ 244,813	$ 244,813	$ 204,813
IOU Fees (Including Billing)												
Cost	$ -	$ -	$ -	$ 98,390	$ 98,390	$ 1,633	$ 1,610	$ 6,598	$ 4,421	$ 55,373	$ 49,189	$ 52,860
Grand Total	$ 116,613	$ 104,613	$ 104,613	$ 276,128	$ 216,128	$ 176,971	$ 230,360	$ 221,744	$ 311,517	$ 543,689	$ 551,764	$ 509,435

Estimated Staffing Costs

The following table provides the estimated staffing budgets for the startup period, reflecting the staffing plan described in Chapter 2. Staffing budgets include direct salaries and benefits loading. As previously noted, the staffing roles would not necessarily be conducted internally. At a minimum, Marin Clean Energy would have four staff positions as described in Chapter 2. The other staffing estimates are used for budgetary purposes.

Staffing Plan (FTEs)	Pre-Startup					Enrollment 1 – Pilot Phase		Cutover 1	Phase 1 Operations	Notification and Enrollment Period		Cutover 2
Staff	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
Management												
Executive Director	$ 21,250	$ 21,250	$ 21,250	$ 21,250	$ 21,250	$ 21,250	$ 21,250	$ 21,250	$ 21,250	$ 21,250	$ 21,250	$ 21,250
Policy Analyst	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129
Administrative Assistant	$ 7,792	$ 7,792	$ 7,792	$ 7,792	$ 7,792	$ 7,792	$ 7,792	$ 7,792	$ 7,792	$ 7,792	$ 7,792	$ 7,792
Finance and Rates												
Manager	$ -	$ -	$ -	$ -	$ -	$ 17,142	$ 17,142	$ 17,142	$ 17,142	$ 17,142	$ 17,142	$ 17,142
Rates Analyst	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,129	$ 10,129
Accounting/Billing Analyst	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129
Administrative Assistant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales And Marketing												
Manager	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025
Account Representatives	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,388	$ 40,517	$ 40,517
Communications Specialist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,129	$ 10,129	$ 10,129	$ 10,129
Administrative Assistant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,792	$ 7,792	$ 7,792
Energy Efficiency												
Manager	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,025	$ 14,025	$ 14,025	$ 14,025
Project Manager	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,231	$ 36,231	$ 36,231	$ 36,231
Regulatory												
Manager	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025	$ 14,025
Regulatory Analyst	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129
Information Technology												
IT Specialist	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129	$ 10,129
Human Resources												
HR Specialist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,065	$ 5,065	$ 5,065	$ 5,065
Subtotal Staffing	$ 53,196	$ 53,196	$ 53,196	$ 53,196	$ 53,196	$ 70,338	$ 114,750	$ 114,750	$ 180,200	$ 218,379	$ 238,638	$ 238,638

Estimated Infrastructure Costs

Infrastructure or overhead needed to support the organization includes computers and peripheral equipment, office furnishings, office space and utilities. These expenses are estimated at $240,000 during program startup. Office space and utilities are ongoing monthly expenses that will begin to accrue before revenues form program operations commence and are therefore assumed to be financed along with other startup costs.

Infrastructure Costs ($/Month)	Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1	Phase 1 Operations	Notification and Enrollment Period		Cutover 2
	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
Computers	$ 12,000	$ -	$ -	$ -	$ -	$ 3,000	$ 12,000	$ -	$ 16,500	$ 12,000	$ 6,000	$ -
Furnishings	$ -	$ -	$ -	$ 60,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Office Space	$ -	$ -	$ -	$ 10,938	$ 10,938	$ 10,938	$ 10,938	$ 10,938	$ 10,938	$ 10,938	$ 10,938	$ 10,938
Utilities	$ -	$ -	$ -	$ 2,188	$ 2,188	$ 2,188	$ 2,188	$ 2,188	$ 2,188	$ 2,188	$ 2,188	$ 2,188
Subtotal Infrastructure	$ 12,000	$ -	$ -	$ 73,125	$ 13,125	$ 16,125	$ 25,125	$ 13,125	$ 29,625	$ 25,125	$ 19,125	$ 13,125

Utility Implementation and Transaction Charges

The estimated costs payable to the distribution utilities for services related to the CCA program startup period include costs associated with initiating service with the utility, processing of customer opt-out notices, customer enrollment, post enrollment opt out processing, and billing fees. Most of the distribution utilities fees are explicitly stated in the relevant CCA tariffs. One unknown potential cost is any specialized service fee that may be imposed by the distribution utilities to support the planned phase-in of customer enrollments or other specialized services requested from PG&E. This potential cost is captured in the estimated service initiation fee.

Utility Transaction Fees (Units/Month)	Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1	Phase 1 Operations	Notification and Enrollment Period		Cutover 2
Utility Fees	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
Opt-Out Notifications												
Per Account						562	562	562	562	122,208	122,208	1,188
Per Event						1	1	1	1	1	1	1
Post enrollment notification												
Per Account								562				1,188
Service Initiation												
Per Hour				1,200	1,200							
Customer List												
Per Event				1	1				1			
Mass enrollment												
Per Account								562				109,987
Per Event								1				1
Opt-Out Fees												
Per Opt Out						-	-	-	-	6,110	3,666	13
Customer Contact Fee												
Per Minute						34	8	6	8	7,332	1,833	1,222
Billing Fee												
Per Account								562	562	562	562	1,750

Utility Transaction Fees ($/Month)	Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1	Phase 1 Operations	Notification and Enrollment Period		Cutover 2
Utility Fees	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
Opt-Out Notifications												
Per Account	$ -	$ -	$ -	$ -	$ -	$ 202	$ 202	$ 202	$ 202	$ 43,995	$ 43,995	$ 428
Per Event	$ -	$ -	$ -	$ -	$ -	$ 1,400	$ 1,400	$ 1,400	$ 1,400	$ 1,400	$ 1,400	$ 1,400
Post enrollment notification	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225	$ -	$ -	$ -	$ 475
Service Initiation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Hour	$ -	$ -	$ -	$ 96,000	$ 96,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer List	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Event	$ -	$ -	$ -	$ 2,390	$ 2,390	$ -	$ -	$ -	$ 2,390	$ -	$ -	$ -
Mass enrollment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225	$ -	$ -	$ -	$ 43,995
Per Event	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,120	$ -	$ -	$ -	$ 4,120
Opt-Out Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Opt Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,811	$ 1,686	$ 6
Customer Contact Fee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Minute	$ -	$ -	$ -	$ -	$ -	$ 31	$ 8	$ 5	$ 8	$ 6,746	$ 1,686	$ 1,124
Billing Fee												
Per Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 421	$ 421	$ 421	$ 421	$ 1,312
Subtotal	$ -	$ -	$ -	$ 98,390	$ 98,390	$ 1,633	$ 1,610	$ 6,598	$ 4,421	$ 55,373	$ 49,189	$ 52,860

Estimates of Third Party Contractor Costs

Contractor costs include outside assistance for advertising, legal services, resource planning, implementation support, customer enrollment, customer service, and payment processing/accounts receivable and verification. The latter three will be provided by the Program's customer account services provider, and these preliminary estimates will be refined as the services and costs provided by the selected contractor are negotiated. The table below shows the estimated contractor costs during the startup period.

Contractor Costs ($/Month)	Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1	Phase 1 Operations	Notification and Enrollment Period		Cutover 2
Contractor Costs	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
General advertising	$ -	$ -	$ -	$ -	$ -	$ 20,000	$ 20,000	$ 10,000	$ 20,000	$ 50,000	$ 50,000	$ 10,000
Legal	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667
Resource Planning	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ 12,500
Implementation Support	$ 22,917	$ 22,917	$ 22,917	$ 22,917	$ 22,917	$ 22,917	$ 22,917	$ 22,917	$ 22,917	$ 22,917	$ 22,917	$ 22,917
Customer Enrollment	$ -	$ -	$ -	$ -	$ -	$ 8,396	$ 8,396	$ 8,396	$ 8,396	$ 33,583	$ 33,583	$ 33,583
Customer Care (Call Center)	$ -	$ -	$ -	$ -	$ -	$ 8,396	$ 8,396	$ 8,396	$ 8,396	$ 100,750	$ 100,750	$ 100,750
Accounts Receivable and Verification	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,396	$ 8,396	$ 8,396	$ 8,396	$ 8,396
Total Contractor Costs	$ 51,417	$ 51,417	$ 51,417	$ 51,417	$ 51,417	$ 88,875	$ 88,875	$ 87,271	$ 97,271	$ 244,813	$ 244,813	$ 204,813

Financing Plan

The initial start-up funding would be provided by MCE via a short-term financing, likely a letter of credit. MCE would recover the principal and interest costs associated with the start-up funding via retail rates. It is anticipated that the start-up costs would be fully recovered within the first two to three years of the Program operations through retail rates.

Working Capital

For purposes of determining working capital requirements related to power purchases, it is assumed that operating revenues from sales of electricity will be remitted to MCE on approximately day 47 of Program operations, based on PG&E's standard meter reading cycle of 30 days and PG&E's payment/collections cycle of 17 days. Either the electric supplier or MCE will be responsible for providing the working capital needed to support electricity procurement, subject to the outcome of negotiations with the selected electric supplier.[28] If it is the electricity provider, this cost will be reflected in its price for providing full requirements electric service to the Program. Regardless, of this being provided by the third party supplier or MCE, Marin Clean Energy will be obligated to meet working capital requirements related to Program management, which will be included in the short term financing associated with start-up funding.

Pro Forma

Ongoing operating expenses will be recovered from revenues accruing from sales of electricity to Program customers and, where applicable, sales of excess power to other entities. Pro forma projections for the initial four years of program operations are shown in this chapter. Pro forma projections for the longer term are included in Appendix A.

Marin Clean Energy Financings

It is anticipated that at least three financings will be necessary in support of the CCA Program. The anticipated financings are listed below and discussed in greater detail.

[28] The cost of short term debt issued by Marin Clean Energy is likely to be lower than the costs a supplier would charge to carry the float on MCE's power purchases. This assumption should be confirmed once MCE's financings are arranged with its bank and a primary electric supplier has been selected.

CCA Program Start-up and Working Capital (Phases 1 and 2)
As previously discussed, the anticipated start-up and working capital requirements for the CCA Program through Phase 2 are $6.4 million. Depending upon the arrangements made between MCE and the third party supplier, this amount could potentially be as low as $3.1 million because $3.3 million of the estimated start-up and working capital requirements is for working capital related to power purchases that may ultimately be carried by the Program's electric supplier (rather than MCE). Once the CCA Program is up and running, these costs would be recovered from the retail customers through retail rates. It is likely that these costs may need to be carried until such time as MCE's generation resource begins operations.[29] Actual recovery of these costs will be dependent on third-party electricity purchase prices and decisions regarding rates, and negotiations between the electric supplier and MCE's Board of Directors regarding initial rates for Phase 1 and 2 customers.

It is assumed that this financing will be via a letter of credit (LOC), which would allow MCE to draw cash as required and that the LOC could be sized (or increased) should it be needed for working capital in Phase 3. This financing would need to commence in mid 2008.

CCA Program Working Capital (Phase 3)
The next potential financing would be working capital for Phase 3. As mentioned above, this could be just an extension (increase) of the LOC for the Program's start-up and working capital. Depending upon market conditions, and payment terms established with the third-party supplier, it may be necessary to increase the LOC to an approximate amount of $15.8 million (or more) in "float" for the start of Phase 3. This number would be refined as the CCA Program was operational and bids were received and evaluated from power providers. The need for this level of working capital can be greatly reduced if MCE can put the payment "float" to the third-party energy supplier.

Renewable Resource Project Financing
MCE's CCA program acticipates large project financings for renewable resources (likely wind and biomass), currently estimated to be in the $475 million range (combined). These financings would occur once specific projects are completely sited and the CCA Program is up and running. The anticipated date for financial close for the renewable resource projects is late 2010. This financing would take out any short-term financing for the renewable resource project development costs, and will be in the range of a 20- to 30-year term.

The security for these bonds would be a hybrid of the revenue from sales to the retail customers of MCE, including a Termination Fee (discussed in greater detail in Chapter 5) and the renewable resource project itself.

PG&E is obligated to collect the CCA's charges for customers of the CCA pursuant to Rule 23, and, for formerly CCA customers that return to PG&E bundled service, PG&E will collect the charges specified by the CCA in the final CCA bill. The Termination Fee could be assessed as a lump sum for inclusion in the final CCA bill for customers leaving the CCA Program. There is uncertainty whether PG&E would collect the Termination Fee if it were spread out and

[29] Interest expense is estimated at 6%.

collected on a continuing basis after customers leave the CCA Program. PG&E has indicated its willingness to discuss a servicing agreement for ongoing collection of the Termination Fee from customers returning to PG&E service, assuming its costs are covered by the CCA Program, but additional discussions would be needed to negotiate the specifics of the agreement. Although PG&E is under no explicit obligation to collect ongoing CCA charges after a customer returns to PG&E bundled service, there would be little justification, if any, for PG&E to refuse to provide such a service to MCE, as long as PG&E is reimbursed for its costs of providing the service. This is particularly true in the context of the statutory requirement for PG&E to fully cooperate with community choice aggregators. There is also a good precedent for such an arrangement in the case of load that has departed PG&E service for service by a municipal utility. In these cases, PG&E has proposed that the municipal utility collect PG&E's departing load Cost Responsibility Surcharges, analogous to the Termination Fee proposed here, on behalf of PG&E.

It is likely that Marin Clean Energy would obtain additional financing capability after it has been operating successfully for a number of years and after the capital markets gain experience and comfort with the CCA business model. If actual experience shows that customer attrition is minimal, MCE should be able to finance investments with less stringent security requirements (i.e., without the need for a Termination Fee). Additional investment by MCE would create greater ratepayer benefits because power purchases would be displaced by production from lower cost community owned resources. MCE may also be able to purchase a portion of its renewable supplies from other public agencies without incurring additional debt, and if these purchases can be made at cost, additional financial benefits beyond those shown in this business plan can be obtained. MCE should initiate discussions soon after its formation to explore opportunities for purchasing renewable energy financed by existing public agencies such as NCPA, SCPPA, SMUD, etc.

All financial pro formas prepared for this business plan assume that the debt service costs associated with the renewable resource project, as well as all fixed and variable costs will be recovered in the retail rates charged to the CCA Program customers. In addition, the financial pro forma includes a debt service coverage ratio of at least 1.25. Actual debt service coverage ratios will be determined during the financing phase of the renewable resource project; however, an increase in the coverage requirements, or increase in the total costs of the renewable resource project (within reason) should not have a material impact on the overall CCA Program.

The following table summarizes the potential financings in support of the CCA Program:

Proposed Financing	Estimated Total Amount	Estimated Term	Estimated Issuance
1. Start-Up and Working Capital (Phase 1 and 2)	$6.4 million	No longer than 7 years	Mid 2009
2. Working Capital (Phase 3)	$15.8 million	No longer than 5 years	Late 2010
3. Renewable Resource Project Financings	$475 million (aggregate)	20-30 years	Late 2011

Sensitivities and Uncertainties

The primary focus of this section is to address the uncertainties and risks that could jeopardize the ability of the Program to offer competitive rates and services to its customers. Any risks to the Marin Communities themselves should be addressed by outside legal counsel retained by the county and cities. Qualified legal counsel will be required to draft the formal governance and program agreements and must make the ultimate determination of whether there would be any residual risk taken on by the Marin Communities through their participation in the Program. The financing plan will also require review and input by legal counsel and potentially investment bankers selected by the county and cities to confirm the ability to obtain financing for the proposed Program.

A quantitative risk analysis will be included in a future revision or supplement to this business plan. The following discussion provides an overview of the risks and uncertainties inherent in implementing the proposed CCA program.

According to the Implementation Timeline described in Chapter 1, certain currently unknown factors that impact the overall economic feasibility of the Program would be resolved before the time the Marin Communities make the final decision to proceed with CCA implementation, while other unknowns would continue after the program begins providing service to customers. Factors that will be known prior to the final decision to proceed with CCA implementation include:

- Participation in MCE by each City;
- The CPUC's actions, if any, on the Implementation Plan submitted by MCE; and
- Initial costs through 2013 for electric supply and customer account services.

It is presumed that the Marin Communities would not authorize the Program to begin unless the costs offered by electric providers to MCE are low enough to enable the Program to offer its desired level of renewable energy while charging rates to customers consistent with the rate projections presented in this plan. Timing of the initial supply contracts will be critical because the wholesale market moves up or down daily and the price swings could be enough to impact the ability to offer competitive rates through the Program. For instance, a 5 percent increase in market prices would increase MCE's annual cost by nearly $6 million, enough to turn a projected surplus for 2011 into a deficit. The outcome of these unknowns will be factored into the final evaluation to be made prior to the time MCE would submit its registration materials to the CPUC. These factors are therefore not Program risks per se, but are uncertainties that may adversely impact the ultimate feasibility of going forward with the Program.

Other factors, listed below, will continue as uncertainties after implementation of the Program. These variables can impact the program's costs or its competitive position relative to services and rates offered by PG&E.

- The level of PG&E rates in general and for customers served by the CCA program in particular;
- The Cost Responsibility Surcharge and rates for utility services provided to the CCA;

- Future wholesale electricity prices;
- The precise costs and timing of future resource investments by MCE; and
- Customer opt-outs and turnover.

Once Marin Clean Energy locks in the price of its initial supply contract, the primary risk is that market prices subsequently decline and PG&E increases the CRS in future years. MCE's costs and rates would be largely predictable due to execution of long term contracts and renewable resources investments, but customer rate impacts can only be known with certainty one year in advance because the CRS is determined one year at a time. Furthermore, PG&E generation rates are volatile and unpredictable; PG&E has been unable to accurately forecast its own generation rates even on a year ahead timeframe. The most significant market-related risk to the program's viability would be a period of sustained low electricity prices beginning after MCE makes long term power supply commitments to renewable resources or other fixed priced electric supplies. MCE's power supply costs would be relatively stable, but reductions in the market prices of wholesale electricity would tend to increase the CRS charged by PG&E to Program customers. Such declines would also tend to reduce PG&E's rates to some extent. If prices for conventional electricity were to drop for a sustained period of time, the Program's rates could be consistently higher than those offered by PG&E. Customers would bear the risk of being obligated to pay MCE's rates or pay the Termination Fee to leave the program. MCE's strong commitment to renewable energy resources could be more costly than anticipated on a relative basis if fossil fuel prices were to experience steep declines in the future. This risk will be evaluated through a scenario analysis that examines the rate impact of shifts in fossil fuel prices, rather than year-to-year price volatility.

Year-to-year fluctuations in market prices would be of less concern if Program customers perceive the rate impacts to be temporary; there are practical restrictions on customers switching back and forth between CCA and utility bundled service. Customers electing to return to the utility would by charged the Termination Fee by MCE and would be obligated to remain with the utility for a three-year commitment pursuant to the Bundled Portfolio Service conditions for returning customers set forth in the utility's tariffs. A departing customer would also need to consider whether it may be foregoing future benefits provided by the CCA.

The other primary uncertainty is the future level of PG&E's generation rates that would otherwise be paid by program customers. Small differences in the escalation rate of PG&E"s generation rates would have significant impacts on the ability of the CCA Program to provide ratepayer benefits. PG&E rates are impacted by market factors such as power supply costs but are also significantly impacted by regulatory policies, which make the task of accurately forecasting PG&E's rates extremely difficult. The forecast underlying this business plan projects an average increase of 3.5 percent per year in PG&E's generation rates, which is relatively low by historical standards. The average annual increase in PG&E's electric rates has been 4.1 percent since 1980 and 5.2 percent since 2000. However, PG&E adjusts its rates at least annually, and actual PG&E rates will only be known with the benefit of hindsight.

Faced with the fact that rate comparisons beyond one year are inherently uncertain, public decision makers need to consider the range and likelihood of the potential outcomes if the decision to offer a CCA program is made.

Other Risks and Uncertainties

Other uncertainties impacting the overall business environment in which the program would operate include two regulatory and legislative changes:

- The impact of AB32, the Greenhouse Gas Reduction law; and
- The impact of PG&E's advanced metering infrastructure program.

<u>AB 32</u>

AB 32 imposes a statewide requirement to reduce greenhouse gas emissions by 25 percent by 2020. The rules governing particular industries have yet to be determined, and it is not possible at this time to predict AB 32's impact on PG&E or the CCA program. It is possible that AB 32 will further drive up demand for renewable energy resources and make early renewable energy investments by MCE that much more attractive. PG&E rates may increase more than projected, and MCE may be able to financially benefit (offer lower rates) by trading emissions reductions achieved through the CCA. On the other hand, AB 32 may motivate PG&E to increase its renewable energy procurement, and the increased demand for renewable resources could reduce supplies available to MCE or leave only the least economic resources available. PG&E's rates would be expected to increase as well. A subsequent analysis should be performed once the implementing regulations have been established.

It is too soon to predict what the financial impacts of AB32 will be and what changes, if any, will be made by PG&E in its future resource procurements. At this point in time, the impact of AB32 should be considered primarily from a policy perspective; i.e., if the state is successful in achieving the greenhouse gas reductions mandated by AB32, is there still a need for direct action by the Marin Communities to promote renewable energy? How confident are the county and cities that actions by the state will be effective? Are the benefits of local control and reduced rates sufficient to outweigh the risks of implementing a CCA? These questions can only be answered by leaders of the Marin Communities and community members following a thorough consideration of the CCA business plan.

<u>Advanced Metering</u>

The plan for PG&E to install advanced metering for all customers, including all 3.5 million residences in PG&E's service territory, creates risks and opportunities for the CCA program. From the risk perspective, advanced metering enables PG&E to offer additional rate options such as critical peak pricing tariffs that may benefit customers located in the Marin Communities. Such options could make it more difficult to for the CCA program to compete with PG&E, unless the CCA offers similar rate options. Moreover, PG&E's critical peak pricing tariffs could have the effect of subsidizing electric customers in the Marin Communities because there is very little air conditioning use in the area, and Marin customers would likely benefit from enrolling in the critical peak pricing rate without changing their consumption patterns (free ridership). From the opportunity perspective, universal deployment of advanced meters would make it possible for MCE to procure electricity based on the actual load profile of customers enrolled in the program as opposed to the current system of using typical customer class "load profiles" estimated based on statistical samples. Using actual load profiles rather than the PG&E class average load profiles should reduce MCE's peak capacity and energy requirements and thus reduce overall electricity procurement costs. This is another area where additional analysis may be warranted as PG&E's plans are implemented.

CHAPTER 5 – Ratesetting and Program Terms and Conditions

Introduction

This Chapter describes the initial policies proposed for Marin Clean Energy in setting its rates for electric aggregation services. These include policies regarding rate design, objectives, and provision for due process in setting Program rates. This section also presents a comparison of preliminary program rates to the distribution utility rates projected to be in effect at Program initiation. Final Program rates would be approved by the Board and included in the initial customer opt-out notices.

MCE's Board of Directors would approve the rate policies and procedures set forth in MCE's adopted Implementation Plan to be effective at Program initiation. The Board would retain authority to modify program policies from time to time at its discretion.

Rate Policies

MCE would establish rates sufficient to recover all costs related to operation of the program, including any reserves that may be required as a condition of financing and other discretionary reserve funds that may be approved by the Board of Directors. As a general policy, rates will be uniform for all similarly situated customers enrolled in the program throughout the service area of MCE, comprised of the jurisdictional boundaries of its members. It is not anticipated that each member would establish its own rates.

The primary objectives of the ratesetting plan are to set rates that achieve the following:

- 100 percent renewable energy supply option – 100 percent Green Tariff;
- Rate competitive tariff option – Light Green Tariff;
- Rate stability;
- Equity among customers in each tariff;
- Customer understanding; and
- Revenue sufficiency.

Each of these objectives is described below.

Rate Competitiveness

The goal is to offer competitive rates for the electric services MCE would provide to participating customers. For participants in MCE's Light Green Tariff, the goal would be for MCE's rates to be equivalent to the generation rates offered by PG&E. For participants in MCE's 100 percent Green Tariff, the goal would be to offer the lowest possible customer rates with an incremental monthly cost increase of 10 percent or less.

Competitive rates will be critical to attracting and retaining key customers, especially the high margin commercial and industrial customers enrolled during Phase 2 that would provide the majority of the program's revenues. As discussed above, the principal long-term program goal is to achieve 100 percent renewable energy supply subject to economic and operating constraints. As previously discussed, the program will significantly increase renewable energy supply to program customers, relative to the incumbent utility, by offering two distinct rate tariffs. The default tariff for program customers will be the 100 percent Green Tariff, which will supply participating customers with 100 percent renewable energy supply at rates that reflect the program's cost for procuring necessary energy supplies. MCE will also offer its customers a Light Green Tariff, which will maximize renewable energy supply (25 percent in 2010, increasing to 51 percent by 2014) while maintaining generation rates that are equivalent to PG&E. Participating qualified low- or fixed-income households, such as those currently enrolled in the California Alternate Rates for Energy (CARE) program, will be automatically enrolled in the Light Green Tariff and will continue to receive related discounts on monthly electricity bills. Based on projected participation in each tariff, the amount of renewable energy supplied to program customers as a percentage of the program's total energy requirements is more than 80 percent in 2014. This estimate is based on informal discussions with potential suppliers. The ability to meet this objective will be confirmed once firm bids are received from third party suppliers.

For the post implementation period, beginning in 2014, it is anticipated MCE will begin utilizing electricity produced by the proposed community wind and biomass projects, and this will help to reduce the program's supply costs and customer rates.

Rate Stability
MCE would offer stable rates by hedging its supply costs over multiple time horizons. Rate stability considerations may mean that program rates relative to PG&E's may differ at any point in time from the general rate targets set for the program. Although MCE's rates would be stabilized through execution of appropriate price hedging strategies, the distribution utility's rates can fluctuate significantly from year-to-year based on energy market conditions such as natural gas prices, the utilities' hedging strategies, and hydro-electric conditions; and from rate impacts caused by periodic additions of generation to utility rate base. MCE would have more flexibility in procurement and ratesetting than PG&E to stabilize electricity costs for customers.

Equity among Customer Classes
MCE's policy would be to provide rate benefits to all customer classes relative to the rates that would otherwise be paid to the local distribution utility. Rate differences among customer classes will reflect the rates charged by the local distribution utility as well as differences in the costs of providing service to each class. Rate benefits may also vary among customers within the major customer class categories, depending upon the specific rate designs adopted by the Board of Directors.

Customer Understanding
The goal of customer understanding involves rate designs that are relatively straightforward so that customers can readily understand how their bills are calculated. This not only minimizes customer confusion and dissatisfaction but will also result in fewer billing inquiries to MCE's customer service call center. Customer understanding also requires rate structures to make sense (i.e., there should not be differences in rates that are not justified by costs or by other policies such as providing incentives for conservation).

Revenue Sufficiency
MCE's rates must collect sufficient revenue from participating customers to fully fund MCE's annual budget. Rates would be set to collect the adopted budget based on a forecast of electric sales for the budget year. Rates would be adjusted as necessary to maintain the ability to fully recover all of MCE's costs, subject to the disclosure and due process policies described later in this chapter.

100 percent Renewable Energy Delivery – "100 percent Green Tariff"
Because the Marin Communities have expressed an interest in increasing the supply of renewable energy as soon as practical, MCE proposes to create a Green Tariff, which would allow interested customers to procure and receive 100 percent renewable energy supply. The 100 percent Green Tariff would be MCE's default tariff, unless a customer of the program elects to participate in the Light Green Tariff option. As previously noted, participating qualified low- or fixed-income households, such as those currently enrolled in the California Alternate Rates for Energy (CARE) program, will be automatically enrolled in the Light Green Tariff and will continue to receive related discounts on monthly electricity bills. Achieving high levels of participation in such a tariff require a well-developed marketing effort by MCE to promote this opportunity. Due to the relatively high cost per kWh of renewable power under current market conditions, a 100 percent Green Tariff of this sort would necessarily impose a per-kWh premium for all energy delivered to participating customers. The premium would generally range from 1.5 to 2.0 cents/kWh above the basic tiered tariff for each customer class. Such a premium would result in an incremental monthly cost increase of $7.50 to $10.00 for a customer using 500 kWh/month, but would supply each participating customer with 100 percent renewable energy, approximately double the level of renewable energy supplied through MCE's Light Green Tariff option and at least five times the renewable energy offered by PG&E. The actual premium charged in relation to the 100 percent Green Tariff would be based on the current cost of renewable energy supply incurred by MCE and may vary slightly from the guideline noted above.

By developing a 100 percent Green Tariff alternative for program customers, it is estimated that MCE's renewable energy supply, expressed as a percentage of total energy supply, would increase to a level above 80 percent by 2014 (the fifth year of program operations). The extent to which this percentage may be increased is ultimately dependent upon the marketing efforts of MCE and the willingness of customers to incur an incremental cost increase for program service. Based on responses to the Marin County 2007 Resident Satisfaction Survey and likely increases in 100 percent Green Tariff participation resulting from effective marketing efforts of the program, it appears that the program could achieve more than 80 percent renewable supply by 2014. Additional market research should be conducted to refine the participation assumptions.

Rate Design
Marin Clean Energy's rate designs would, at least initially, generally mirror the structure of PG&E's generation rates so that similar rate impacts can be provided to MCE's customers. For example, PG&E's residential rates include different rates applicable to five increasing tiers of consumption; as customers use more energy, the rate progressively increases to encourage conservation. MCE's rates would similarly follow a five-tier structure. Rates for other customer

classes include peak demand charges and other charges that vary based on the time period during which the energy or peak demand is consumed (time-of-use rates). MCE would generally match the rate structures from the utilities' standard rates to avoid the possibility that customers would see significantly different bill impacts as a result of changes in rate structures when beginning service in MCE's program. MCE may also introduce new rate options for customers, such as rates designed to encourage economic expansion or business retention within MCE's service area.

One proposed rate design approach would apply an equal percentage discount, if applicable, to the otherwise applicable rate for all of the various rate schedules offered by PG&E. All customers, including low use residential and customers receiving low income discounts would receive the same rate benefit on a percentage basis. While simple in concept, this approach implies a fairly complicated rate structure for MCE as it matches the rate structures used by PG&E. PG&E's optional "rate ready" billing service, where PG&E calculates bills using MCE's rates, could not be utilized because PG&E limits the complexity of the CCA rate structure it will accommodate for this service.[30] It would also tend to price services to some customers or during certain time-of-use periods below MCE's actual cost of providing service. For example, a low use residential customer that used only the minimal baseline usage in a month currently pays less than five cents per kWh for generation services, which is below the cost of purchasing the power from the wholesale market. If MCE discounted all rates equally, MCE's rate would also be below its costs.

The proposed equal benefits rate design is recommended in order to facilitate easy rate comparisons and provide for a smooth transition of customers from PG&E service to CCA service. MCE would have discretion to modify its rate design policies, and it is likely that over time MCE's rate design would become less tied to those offered by PG&E.

An alternative rate design approach would primarily consider cost of service in setting customer rates and establish a cost based floor below which rates would not be set. MCE may also simplify rate structures, for instance by eliminating demand charges or reducing/eliminating the residential tier rate structure. Rate comparisons would then vary on a customer-by-customer basis and some customers who MCE can not cost-effectively serve would have the incentive to remain with PG&E. Such an approach would allow for greater rate benefits for the customers that join the program because they would no longer be subsidizing others. A simpler, more cost based, rate structure would be easier to administer as well. The downside is that the Program would not provide equal benefits to all customers. The initial customer communications effort would be complicated by the inability to provide rate comparisons that would be meaningful and accurate for all customers. Rates for typical customers of each class could be easily compared, but individual customer rate impacts would vary. It should also be understood that a more cost based rate structure would generally favor the commercial and industrial customer classes relative to residential and small commercial customers, and the Program could be faulted for using rate design to exclude small users, even

[30] Notwithstanding the fact that the proposed rate design approach would utilize the identical rate structures that PG&E uses to bill its own customers.

if that is not the intent.[31] A fully cost-based rate design would not be consistent with a goal of maximizing customer participation and providing benefits to all ratepayers. As previously noted, the program anticipates an initial rate structure equivalent to that of PG&E. Over time, MCE may elect to incorporate one of the previously described rate design proposals.

Net Energy Metering

Customers with on-site generation eligible for net metering from PG&E would be offered a net energy metering rate from MCE. Net energy metering allows for customers with certain qualified solar or wind distributed generation to be billed on the basis of their net energy consumption. The PG&E net metering tariff (E-NEM) requires the CCA to offer a net energy metering tariff in order for the customer to continue to be eligible for service on Schedule E-NEM. The objective is that MCE's net energy metering tariff would apply to the generation component of the bill, and the PG&E net energy metering tariff would apply to the utility's portion of the bill. To the extent that current CPUC regulations governing provision of net energy metering to CCA customers are unclear, MCE would work with PG&E and the CPUC to establish a net energy metering tariff that accomplishes this objective.

Rate Impacts

The projected rates shown below would require a price for full requirements electric supply of approximately 8.8 cents per kWh. ***These rates are illustrative, and the ability to offer the targeted rate discount must still be confirmed through the RFP process described in Chapter 6.***

Marin Clean Energy Estimated 2011 Program Rates

Customer Class	Program Rates – Green	Program Rates – Light Green	PG&E Generation Rate
	(Cents Per kWh)	(Cents Per kWh)	(Cents Per kWh) *
Residential	11.3	9.4	9.4
Small Commercial	11.5	9.6	9.6
Medium Commercial	11.1	9.3	9.3
Medium Industrial	10.2	8.5	8.5
Large Industrial	9.7	8.1	8.1
Agricultural	9.5	7.9	7.9
Street and Area Lighting	9.7	8.1	8.1
PG&E rates are based on those contained in Advice Letter No. 3115-E-A (Effective January 1, 2008), escalated by 3.5% per year.			

Individual customers within rate classes may pay higher or lower average rates than those shown above depending on their electricity usage and load profile as is the case with PG&E. MCE's rates shown include all costs expected to be incurred by MCE related to the aggregation program, including power supply costs, operations and administration costs, reserves, and

[31] MCE could offer rate discounts or other forms of assistance (e.g., energy efficiency programs) to certain customer populations that might otherwise be disadvantaged by a more cost based rate structure.

billing and metering fees charged by PG&E to MCE. For the sake of comparison, MCE's rates are shown inclusive of the cost responsibility surcharges that MCE's customers will pay directly to PG&E. Program rates for the Light Green Tariff are designed to provide participating customers with rate equivalency to PG&E.

Disclosure and Due Process in Setting Rates and Allocating Costs among Participants
Initial program rates would be adopted by the Board of Directors following the establishment of the first year's operating budget prior to initiating the customer notification process. Subsequently, the Executive Director, with support of the Energy Commission described in Chapter 2, would prepare an annual budget and corresponding customer rates and submit these as an application for a change in rates to the Board of Directors. The rates would be approved at a public meeting of the Board of Directors no sooner than sixty days following submission of the proposed rates, during which affected customers would be able to provide comment on the proposed rate changes.

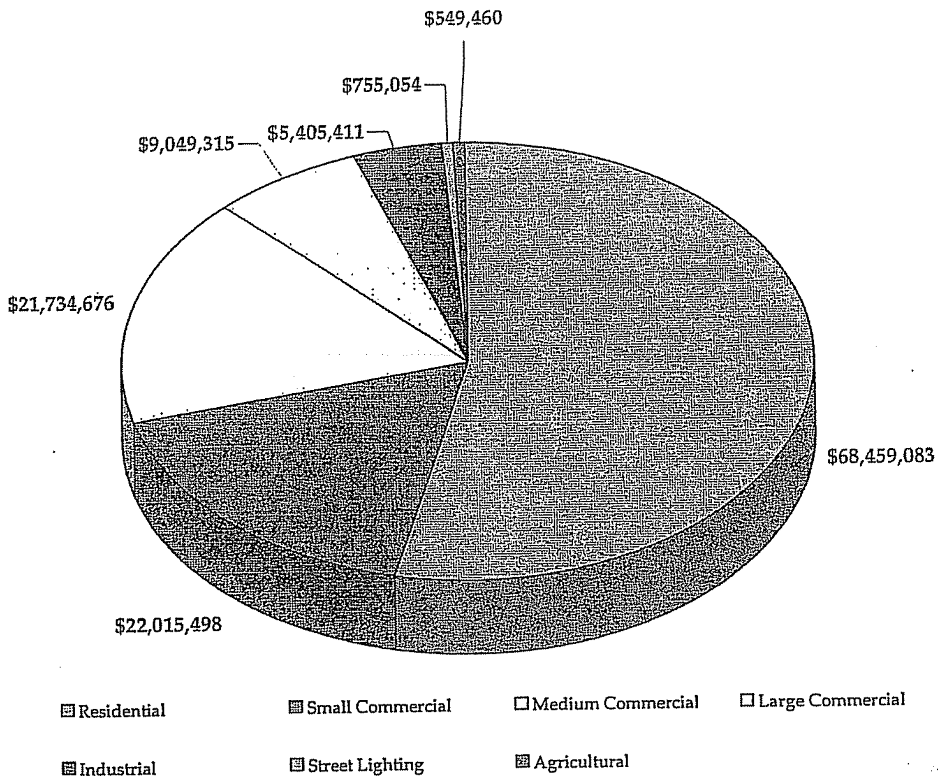
MCE would initially adopt customer noticing requirements similar to those the CPUC requires of PG&E and SCE. These notice requirements are described as follows:

Notice of rate changes will be published at least once in a newspaper of general circulation in the county within ten days of after submitting the application. Such notice will state that a copy of said application and related exhibits may be examined at the offices of MCE as are specified in the notice, and shall state the locations of such offices.

Within forty-five days after the submitting an application to increase any rate, MCE will furnish notice of its application to its customers affected by the proposed increase, either by mailing such notice postage prepaid to such customers or by including such notice with the regular bill for charges transmitted to such customers. The notice will state the amount of the proposed increase expressed in both dollar and percentage terms, a brief statement of the reasons the increase is required or sought, and the mailing address of MCE to which any customer inquiries relative to the proposed increase, including a request by the customer to receive notice of the date, time, and place of any hearing on the application, may be directed.

Projected revenues from energy sales to the primary customer classes to be served by MCE are shown in the following chart:

Projected 2011 Revenues by Customer Class (Dollars)



Customer Rights and Responsibilities

This section discusses customer rights, including the right to opt out of the Program, as well as obligations customers undertake upon agreement to enroll in the aggregation Program. It includes a preliminary methodology for determining fees that would apply to customers who terminate service after the initial free opt-out period. All customers that do not opt out within 60 days of enrollment (after having received four opt-out notices) will have agreed to become full status Program participants and must adhere to the customer obligations that would be set forth in MCE's adopted Implementation Plan.

Customer Notices

At the initiation of the customer enrollment process, a total of four notices would be provided to customers describing the Program, informing them of their opt-out rights to remain with utility bundled generation service, and containing a simple mechanism for exercising their opt-out rights. The first notice will be mailed to customers approximately sixty days prior to the date of automatic enrollment. A second notice will be sent approximately thirty days later. Marin Clean Energy would likely use its own mailing service for the initial opt-out notices rather than including the notices in PG&E's monthly bills. This is intended to increase the likelihood that customers will read the opt-out notices, which may otherwise be ignored if included as a bill insert. As required by CPUC regulations, MCE will use PG&E's opt-out processing service. Customers may opt out by notifying PG&E using the utility's automated telephone system or internet opt out processing services. Consistent with CPUC regulations, notices returned as undelivered mail would be treated as a failure to opt out, and the customer would be automatically enrolled.

Following automatic enrollment, a third opt-out notice will be included with the final bill containing utility generation charges, and a fourth and final opt-out notice will be included with the first bill containing Program charges. Opt-out requests made on or before the sixtieth day following enrollment would result in customer transfer to utility service with no penalty. Such customers will be obligated to pay MCE's charges for electric services provided during the time the customer took service from the Program, but will otherwise not be subject to any penalty or transfer fee from MCE.

New customers who establish service within the Program service area would be automatically enrolled in the Program and would have sixty days from the date of enrollment to opt out of the Program. Such customers would be provided with two opt-out notices within this sixty-day post enrollment period. MCE's Board of Directors would have the authority to implement entry fees for customers that initially opt out of the Program, but later decide to participate. Entry fees would help prevent potential gaming, particularly by large customers, and aid in resource planning by providing additional control over the Program's customer base. Entry fees would not be practical to administer, nor would they be necessary, for residential and other small customers.

Termination Fee

Customers that are automatically enrolled in the Program can elect to transfer back to the incumbent utility without penalty within the first two billing cycles of service. After this free opt-out period, customers would be allowed to terminate their participation subject to payment of a Termination Fee. The Termination Fee would apply to all Program customers that elect to return to bundled utility service or elect to take "direct access" service from an energy services provider. Program customers that relocate within the Program's service territory would have their CCA service continued at the new address. If a customer relocating to an address within the Program service territory elected to cancel CCA service, the Termination Fee would apply. Program customers that move out of the Program's service territory would not be subject to the Program's Termination Fee.

The Termination Fee would consist of two parts: an Administrative Fee set to recover the costs of processing the customer transfer and other administrative or termination costs and a Cost Recovery Charge that would apply in the event MCE is unable to recover the costs of supply commitments attributable to the customer that is terminating service. PG&E would collect the Administrative Fee from returning customers as part of the final bill to the customer from the CCA Program and would collect the Cost Responsibility Charge (CRC) as a lump sum or on a monthly basis pursuant to a negotiated servicing agreement between MCE and PG&E.

The Administrative Fee would vary by customer class as set forth in the table below.

Administrative Fee for Service Termination

Customer Class	Fee
Residential	$5
Small Commercial	$5
Medium Commercial	$10
Large Commercial	$25
Industrial	$25
Street Lighting	$10
Agricultural and Pumping	$10

The customer CRC will be equal to a pro rata share of any above market costs of MCE's actual or planned supply portfolio at the time the customer terminates service. The proposed CRC is similar in concept to the Cost Responsibility Surcharge charged by PG&E, and it is designed to prevent shifting of costs to remaining Program customers. The CRC will be set on an annual basis by MCE's Governing Board as part of the annual ratemaking process.

The long-term financial projections contained in Appendix A indicate that MCE may be able to offer rates that are generally below those charged by PG&E and that MCE's supply portfolio is projected to be competitive in the marketplace because of the financing advantages that MCE enjoys. Under those conditions, most customers would not be expected to terminate their service with MCE to return to the utility. Furthermore, if customers do terminate service, MCE should be able to re-market the excess supply and fully recover its costs. Although the Cost Recovery Charge will likely not be needed for recovery of stranded costs, MCE's ability to assess a Cost Recovery Charge, if necessary, is an important condition for obtaining financing for MCE's power supply. The low cost financing will, in turn, enable MCE to charge rates that are competitive with PG&E's.

The CRC will also enhance the credit profile of the Program as it relates to credit exposure from the electricity suppliers' point of view. Absent a CRC, the Program would likely need to post cash collateral to match its credit exposure to the Program's electric supplier(s).

The circumstance that would trigger application of the CRC would be if PG&E rates unexpectedly drop below those of MCE and customers wish to leave the Program to return to PG&E. In that scenario, the CRC would reduce some of the customer benefits from switching back to PG&E.

Once finalized, the Termination Fee should be clearly disclosed in the four opt-out notices sent to customers during the sixty-day period before automatic enrollment and following commencement of service. The fee could be changed prospectively by MCE's Board of Directors, subject to MCE's customer noticing requirements.

Customers electing to terminate service would be transferred to PG&E on their next regularly scheduled meter read date if the termination notice is received a minimum of fifteen days prior to that date. Customers who voluntarily transfer back to PG&E would also be liable for the nominal reentry fees imposed by PG&E as set forth in the applicable utility CCA tariffs. Such customers would also be required to remain on bundled utility service for a period of three years, as described in the utility tariffs.

Customer Confidentiality

MCE would establish policies covering confidentiality of customer data. MCE's policies should maintain confidentiality of individual customer data. Confidential data includes individual customers' name, service address, billing address, telephone number, account number and electricity consumption. Aggregate data may be released at MCE's discretion or as required by law or regulation.

Responsibility for Payment

Customers would be obligated to pay MCE charges for service provided through the date of transfer including any applicable Termination Fees. Pursuant to current CPUC regulations, MCE would not be able to direct that electricity service be shut off for failure to pay MCE's bill. However, PG&E has the right to shut off electricity to customers for failure to pay electricity bills, and Rule 23 mandates that partial payments are to be allocated pro rata between PG&E and the CCA. In most circumstances, customers would be returned to utility service for failure to pay bills in full and customer deposits would be withheld in the case of unpaid bills. PG&E would attempt to collect any outstanding balance from customers in accordance with Rule 23 and the related CCA Service Agreement. The proposed process is for two late payment notices to be provided to the customer within 30 days of the original bill due date. If payment is not received within 45 days from the original due date, service would be transferred to the utility on the next regular meter read date, unless alternative payment arrangements have been made. The proposed policy limits collections exposure to two months bills, consistent with the proposed deposit policy explained below. This policy may be modified by MCE's Board based on experience or regulatory changes that would provide MCE with shutoff rights for non-payment. Consistent with the CCA tariffs, Rule 23, service cannot be discontinued to a residential customer for a disputed amount if that customer has filed a complaint with the CPUC, and that customer has paid the disputed amount into an escrow account.

Customer Deposits

Customers may be required to post a deposit equal to two months' estimated bills for MCE's charges to obtain service from the Program. Failure to post deposit as required would cause the account service transfer request to be rejected, and the account would remain with PG&E. Customer deposits would be required based on the Program's credit policy to be adopted by MCE's Board of Directors. It is anticipated that the Program's credit policy would be similar to the customer credit policies employed by PG&E.

This Chapter presents the key elements of a proposed marketing plan for Marin Clean Energy, including the promotion of its 100 percent Green Tariff to community businesses and residents as well as necessary program staff to administer these activities.

Customer Services

As referenced in the Organizational Plan, Chapter 2, the Marin Clean Energy will have seven full-time staff or contractors focused on Sales and Marketing functions at full program implementation (January 2011). These individuals will be responsible for organizing and administering general program communications, customer service and representation for key accounts. Sales and Marketing personnel will also be tasked with implementing a marketing strategy to promote customer satisfaction with the CCA program and developing marketing materials, including bill inserts and a program website for MCE.

A significant focus of this marketing strategy will be to secure and retain the participation of large customers in the CCA program. It is assumed that most residential customers will be compelled to participate in the CCA program based on MCE's significant commitment to renewable energy delivery and carbon emissions reductions with a pricing option that offers rate parity with the incumbent utility, PG&E. While these may also be compelling reasons for some large energy users to participate in the CCA program, others may require additional incentives to engage in this new business relationship. The following section describes potential incentives that could be provided to these large customers to promote participation in the program and, potentially, the Green Power Tariff.

Partnering with Large Customers

Large energy customers, particularly businesses falling into the general rate classifications of "Commercial" and "Industrial," comprise a significant portion of the electric load within the Marin Communities (Commercial customers account for 42 percent of the Marin Communities' electric load; Industrial customers account for 5 percent of total load). To ensure that these accounts remain customers of MCE, it will be important to identify ways in which MCE can add value to these businesses as an energy supplier. For many of these large customers, rate stability and/or an increased commitment to renewable energy supply may be compelling reasons to procure energy from MCE. For other large customers, additional incentives may be necessary to encourage a new business relationship with MCE. In these instances, it will be incumbent upon MCE to develop programs that provide adequate incentives for large energy users to proceed as customers of the CCA.

Because most of these large energy users are producing, selling or distributing goods and/or services, MCE may choose to focus on developing marketing materials, such as a logo or seal, that could be displayed on product packaging, letterhead, buildings, corporate vehicles or in other prominent areas, which would inform customers of each business' commitment to renewable power supply and carbon emissions reductions as a customer of Marin Clean Energy. While the specific graphics and/or verbiage displayed on this logo would need to be developed by MCE, such a logo would likely display the following general message: "Proud Renewable Energy Partner of Marin Clean Energy." A logo or seal of this sort, used under a no-cost licensing agreement with MCE, would differentiate certain businesses and their products from those that did not share the same commitment to renewable power delivery and carbon emissions reductions. This distinction may be viewed by businesses as an important marketing mechanism within the Marin Communities.

In concert with this branding opportunity, MCE could also include a "Business Partners" registry on its website to provide recognition for those businesses that have chosen to proceed with CCA service and the commitment to renewable power delivery and carbon emissions reduction. Business Partners of MCE, in addition to name recognition of MCE's website, might also be given the option to have their contact information displayed to facilitate commerce between residents and other businesses. Such a resource will become a reference point for residents and other businesses within the Marin Communities as they attempt to identify potential vendors that share their commitment to the environment.

Similarly, MCE could develop a second logo or seal for large energy customers who choose to participate in its 100 percent Green Tariff (discussed in Chapter 5). As in the previous example, use of this logo would be permitted under a no-cost licensing agreement for participants in MCE's Green Power Tariff. Due to the increased cost incurred by participants in the 100 percent Green Tariff, MCE may choose to further distinguish this logo or seal by clearly displaying verbiage such as, "Powered by 100 percent Green Energy – Delivered from Marin Clean Energy." Many businesses may find that the rate increase incurred as a result of participating in MCE's 100 percent Green Tariff will be recoverable through nominal increases in product or service pricing. In fact, it seems reasonable to assume that many residents and businesses within the Marin Communities would actively seek out businesses that have made this additional commitment to renewable power delivery and reduced environmental impact. In fact, MCE may choose to provide these Business Partners with additional and prominent, recognition for their participation in the 100 percent Green Tariff by displaying corporate/business logos on the "Home Page" of MCE's website and/or on other marketing materials, such as pamphlets and bill inserts.

Ultimately, the willingness of a large energy customer to receive electric generation service from the CCA will be significantly improved by MCE offering a recognizable means by which these Business Partners can differentiate themselves from other businesses that may elect to opt-out of the program. As a result of the Marin Communities' progressive stance on carbon emissions reduction and renewable power development/delivery, highlighting the commitment of Business Partners to proactively addressing these issues should provide a competitive advantage relative to other businesses within the Marin Communities. Such a competitive advantage may likely increase demand for the products and services offered by these Business Partners.

Introduction
This Chapter describes Marin Clean Energy's initial procurement policies and the key third party service agreements by which MCE would obtain operational services for the CCA Program. MCE's Board of Directors would approve its general procurement policies set forth in an adopted Implementation Plan to be effective at Program initiation. The Board of Directors would retain authority to modify program policies from time to time at its discretion.

Procurement Methods
MCE would enter into agreements for a variety of services needed to support program development, operation and management. It is anticipated MCE would generally utilize Competitive Procurement methods for services but may also utilize Direct Procurement or Sole Source Procurement, depending on the nature of the services to be procured. Direct Procurement is the purchase of goods or services without competition when multiple sources of supply are available. Sole Source Procurement is generally to be performed only in the case of emergency or when a competitive process would be an idle act.

MCE would utilize a competitive solicitation process to enter into agreements with entities providing electrical services for the program. Agreements with entities that provide professional legal or consulting services, and agreements pertaining to unique or time sensitive opportunities, may be entered into on a direct procurement or sole source basis at the discretion of MCE's Executive Director or Board of Directors.

The Executive Director would be required to periodically report (e.g., quarterly) to the Board a summary of the actions taken with respect to the delegated procurement authority.

Authority for terminating agreements would generally mirror the authority for entering into the agreements.

Procurement at Startup
The operational services needed for the program will be competitively procured. To date, the Marin Communities have utilized information received by the SJVPA and the East Bay Communities in response to their non-binding requests for information. These responses provided valuable information regarding seller qualifications as well as indicative cost proposals for energy supply and certain customer service related functions. The indicative pricing information provided by respondents to these requests for information has been incorporated in this business plan. These responses have also provided useful information about resource availability and costs, particularly for renewable energy resources.

Assuming MCE is formed, a binding request for bids would be issued some time in early 2009 to solicit bids for electric supply and customer account services needed for program operations. Firm energy price bids will be solicited for at least the first four years of operations. The selected supplier will be required to have extensive operational experience and must maintain an investment grade credit rating to minimize risks of default. The supplier will be responsible for managing the electric supply portfolio on behalf of MCE and will be required to meet the renewable portfolio requirements specified by MCE as well as other applicable regulatory requirements such as those pertaining to resource adequacy. During this period, the bulk of the risks will be borne by the third party supplier under a "full requirements" electric supply contract.

As a result of the competitive solicitation, electric supply costs will be known for the first four years of program operations based on the firm bids offered by the selected supplier. Bids for customer services needed for the Program (Customer Account Services) will also be solicited. The evaluation of whether to proceed with implementation will therefore incorporate known costs for approximately 95 percent of total program costs for the first four years, providing relative certainty regarding the ability to provide competitive rates. Based on the firm bids, a determination will be made regarding whether the program can achieve its desired renewable energy targets while offering generation rates that are competitive with PG&E during the implementation period. If the program cannot provide competitive rates, a determination would be made whether to adjust the timing for implementation or terminate the program altogether.

Key Contracts

Electric Supply Contract

For the initial four years of program operations (1/1/2010 through 12/31/2013), a third party energy services provider would supply electricity to customers under a full requirements contract. Under a full requirements contract, the supplier commits to serve the total electrical loads of customers in the CCA Program. The supplier is responsible for ensuring that a certified Scheduling Coordinator schedules the loads of all customers in the program and is also responsible for obtaining meter data from PG&E to submit to the CAISO settlement process. The supplier is wholly responsible for the portfolio operations functions and managing all supply risks for the term of the contract. The supplier must meet the Program's renewable energy goals and comply with all resource adequacy and other regulatory requirements imposed by the CPUC or FERC. The contract may further provide for the integration of resources that may be procured separately by the Program.

Risks related to customer opt-outs and changes in program loads during the term of the agreement would be borne by the supplier unless alternative arrangements are agreed to during negotiations. The supplier should be given the opportunity to charge different prices for sales to the various customer classes to help mitigate opt-out risks related to uncertainty in the load profile of the final customer mix.

The supplier must also specify the renewable content of the supply portfolio that will be used to supply the program for each year of the agreement term. Renewable energy disclosed must qualify to meet the California RPS and must be no less than the program's target of 56 percent in 2010, increasing to 70 percent in 2013, adjusted as necessary for actual customer participation.

Data Management Contract

A data manager would provide the retail customer services of billing and other customer account services (EDI with PG&E, billing, remittance processing, account management). Recognizing that some qualified wholesale energy suppliers do not typically conduct retail customer services whereas others (i.e., direct access providers) do, the data management contract is separate from the electric supply contract. A single contractor would be selected to perform all of the data management functions.[32]

The data manager is responsible for the following services:

- Data exchange with PG&E;
- Technical testing;
- Customer information system;
- Customer call center;
- Billing administration/retail settlements; and
- Reporting and audits of utility billing.

Utilizing a third party for account services eliminates a significant expense associated with implementing a customer information system. Such systems can cost from five to ten million dollars to implement and take significant time to deploy. A longer term contract is appropriate for this service because of the time and expense that would be required to migrate data to a new system. Separation of the data management contract from the energy supply contract gives MCE greater flexibility to change energy suppliers, if desired, without facing an expensive data migration issue.

It is anticipated that MCE will issue a binding request for bids some time in early 2009 for data management services. A short list of potential energy suppliers and data management providers selected as a result of this process will reflect a highly qualified pool of suppliers for further negotiations, which will be completed prior to registration of the CCA.

[32] The contractor performing account services may be the same entity as the contractor supplying electricity for the program.

Introduction

This Chapter describes the process to be followed in the case of Program termination. In the unexpected event that MCE would terminate the Program and return its customers to PG&E service, the proposed process is designed to minimize the impacts on its customers and on PG&E. The proposed termination plan follows the requirements set forth in PG&E's tariff Rule 23 governing service to CCAs.

Termination by Marin Clean Energy

Marin Clean Energy would plan to offer services for the long term with no planned Program termination date. In the unanticipated event that the majority of the Member's governing bodies (County Board of Supervisors and/or City Councils) decide to terminate MCE/program, each governing body would be required to adopt a termination ordinance or resolution and provide adequate notice to MCE (such as 90 days). Following such notice, MCE would vote on its termination subject to a two-tiered vote, as previously described. In the event that the Board affirmatively votes to proceed with JPA termination, the Board would disband under the provisions identified in its JPA Agreement. In recognition of this possibility, all contracts executed by the Board will include terms and conditions addressing the resolution of any remaining contractual obligations of the Board (such as contract buyouts, termination payments, contractual assignments, etc.).

After any applicable restrictions on such termination have been satisfied, notice would be provided to customers six months in advance that they will be transferred back to PG&E. A second notice would be provided during the final sixty-days in advance of the transfer. The notice would describe the applicable distribution utility bundled service requirements for returning customers then in effect, such as any transitional or bundled portfolio service rules.

At least one year advance notice would be provided to PG&E and the CPUC before transferring customers, and MCE would coordinate the customer transfer process to minimize impacts on customers and ensure no disruption in service. Once the customer notice period is complete, customers would be transferred *en masse* on the date of their regularly scheduled meter read date.

MCE would maintain funds held in reserve to pay for potential transaction fees charged to the Program for switching customers back to distribution utility service. Reserves would be maintained against the fees imposed for processing customer transfers (CCASRs). The public utilities code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to distribution utility service under certain circumstances. The cost of reentry fees are the responsibility of the energy services provider or the community choice aggregator, except in the case of a customer returned for default or because its contract has expired. The CPUC currently has established a maximum interim CCA bond amount of $100,000 to cover potential reentry fees. The CPUC will be evaluating the appropriate bonding requirements in a future rulemaking.

Termination by Members

The JPA Agreement will define the terms and conditions under which Members may terminate their participation in the program. As described in the proposed governance principles (Chapter 2), a JPA Member would be able to withdraw from the program upon 60 days written notice prior to the expiration of each fiscal year (July 1). The Members withdrawal would then become effective one full fiscal year later, an effective 14-month notice requirement. The withdrawing party would also be subject to all reasonable ongoing costs incurred by MCE on behalf of that entity. In this case, a vote of the Board would not be required to affect Member withdrawal. Furthermore, the municipal load of a Member withdrawing from the JPA would no longer be served by MCE, however, the non-municipal accounts (such as residential, commercial and industrial accounts) would remain customers of MCE and would continue to receive electricity procured by MCE on their behalf. Because these non-municipal accounts would remain customers of MCE, the withdrawing Member would continue to provide a Board representative from among its elected officials to ensure that the interests of its constituents are represented during policy-making decisions of the Board.

Conversely, if a Member desired to remove its future non-municipal accounts from Marin Clean Energy service while retaining service for its municipal accounts, Board approval based on either of the aforementioned two-tiered voting structures would be required. In this instance, any existing non-municipal accounts would continue to receive electric service from MCE; only future non-municipal accounts would be affected. Only in the event that the JPA agrees to disband would the requirement of Board representation by all Members cease.

CHAPTER 9 – Appendices

Appendix A: Pro Forma 2014 – 2025

Appendix B: Energy Efficiency Potential in the Marin Communities

Appendix C: List of Acronyms and Definitions

Appendix A – Pro Forma 2014-2025

MARIN CLEAN ENERGY
FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION

CATEGORY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
I. CUSTOMER ACCOUNTS:												
RESIDENTIAL	98,912	99,406	99,903	100,403	100,905	101,409	101,916	102,426	102,938	103,453	103,970	104,490
SMALL COMMERCIAL1	11,139	11,195	11,251	11,307	11,364	11,421	11,478	11,535	11,593	11,651	11,709	11,767
SMALL COMMERCIAL2	741	745	748	752	756	760	763	767	771	775	779	783
MEDIUM COMMERCIAL	1,083	1,089	1,094	1,100	1,105	1,111	1,116	1,122	1,127	1,133	1,139	1,144
LARGE COMMERCIAL	159	160	161	162	163	164	164	165	166	167	168	168
LARGE COMMERCIAL & INDUSTRIAL	11	11	11	11	12	12	12	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL	550	553	556	559	561	564	567	570	573	576	579	581
AGRICULTURAL	180	181	182	183	183	184	185	186	187	188	189	190
SUBTOTAL - CUSTOMER ACCOUNTS	112,776	113,340	113,907	114,476	115,049	115,624	116,202	116,783	117,367	117,954	118,544	119,136
II. LOAD REQUIREMENTS (KWH):												
RESIDENTIAL	649,953,652	653,203,420	656,469,437	659,751,784	663,050,543	666,365,796	669,697,625	673,046,113	676,411,344	679,793,400	683,192,367	686,608,329
SMALL COMMERCIAL1	148,806,173	149,550,204	150,297,955	151,049,444	151,804,692	152,563,715	153,326,534	154,093,166	154,863,632	155,637,950	156,416,140	157,198,221
SMALL COMMERCIAL2	56,199,568	56,480,566	56,762,969	57,046,784	57,332,017	57,618,678	57,906,771	58,196,305	58,487,286	58,779,723	59,073,621	59,368,989
MEDIUM COMMERCIAL	208,418,179	209,460,270	210,507,571	211,560,109	212,617,910	213,680,999	214,749,404	215,823,151	216,902,267	217,986,778	219,076,712	220,172,096
LARGE COMMERCIAL	106,748,415	107,282,157	107,818,568	108,357,661	108,899,449	109,443,946	109,991,166	110,541,122	111,093,828	111,649,297	112,207,543	112,768,581
LARGE COMMERCIAL & INDUSTRIAL	67,471,395	67,808,752	68,147,796	68,488,535	68,830,978	69,175,132	69,521,008	69,868,613	70,217,956	70,569,046	70,921,891	71,276,501
STREET LIGHTING AND TRAFFIC CONTROL	8,347,852	8,389,591	8,431,539	8,473,696	8,516,065	8,558,645	8,601,438	8,644,446	8,687,668	8,731,106	8,774,762	8,818,636
AGRICULTURAL	6,513,487	6,546,054	6,578,784	6,611,678	6,644,737	6,677,960	6,711,350	6,744,907	6,778,632	6,812,525	6,846,587	6,880,820
SUBTOTAL - LOAD REQUIREMENTS	1,252,458,720	1,258,721,014	1,265,014,619	1,271,339,692	1,277,696,390	1,284,084,872	1,290,505,297	1,296,957,823	1,303,442,612	1,309,959,825	1,316,509,625	1,323,092,173
III. IOU UNBUNDLED RATE FOR GENERATION COMPONENT ($/KWH):												
RESIDENTIAL	$0.104	$0.108	$0.111	$0.115	$0.119	$0.123	$0.128	$0.132	$0.137	$0.142	$0.147	$0.152
SMALL COMMERCIAL1	$0.108	$0.1116	$0.116	$0.120	$0.124	$0.128	$0.133	$0.137	$0.142	$0.147	$0.152	$0.157
SMALL COMMERCIAL2	$0.102	$0.106	$0.110	$0.114	$0.118	$0.122	$0.126	$0.130	$0.135	$0.140	$0.145	$0.150
MEDIUM COMMERCIAL	$0.103	$0.107	$0.111	$0.114	$0.118	$0.123	$0.127	$0.131	$0.136	$0.141	$0.146	$0.151
LARGE COMMERCIAL	$0.094	$0.097	$0.101	$0.104	$0.108	$0.112	$0.116	$0.120	$0.124	$0.128	$0.133	$0.137
LARGE COMMERCIAL & INDUSTRIAL	$0.089	$0.093	$0.096	$0.099	$0.103	$0.106	$0.110	$0.114	$0.118	$0.122	$0.126	$0.131
STREET LIGHTING AND TRAFFIC CONTROL	$0.089	$0.092	$0.096	$0.099	$0.102	$0.106	$0.110	$0.114	$0.118	$0.122	$0.126	$0.130
AGRICULTURAL	$0.088	$0.091	$0.094	$0.097	$0.101	$0.104	$0.108	$0.111	$0.115	$0.119	$0.124	$0.128
SUBTOTAL - AVERAGE RATE	$0.097	$0.101	$0.104	$0.108	$0.112	$0.115	$0.120	$0.124	$0.128	$0.133	$0.137	$0.142
IV. IOU REVENUE REQUIREMENT FOR POWER SUPPLY ($):												
RESIDENTIAL	$67,584,244	$70,299,441	$73,123,722	$76,061,467	$79,117,236	$82,295,771	$85,602,004	$89,041,065	$92,618,289	$96,339,229	$100,209,658	$104,235,581
SMALL COMMERCIAL1	$16,050,658	$16,695,493	$17,366,235	$18,063,923	$18,789,641	$19,544,515	$20,329,716	$21,146,462	$21,996,021	$22,879,711	$23,798,904	$24,755,025
SMALL COMMERCIAL2	$5,758,794	$5,990,153	$6,230,808	$6,481,130	$6,741,510	$7,012,350	$7,294,071	$7,587,110	$7,891,922	$8,208,980	$8,538,776	$8,881,822
MEDIUM COMMERCIAL	$21,510,917	$22,375,118	$23,274,038	$24,209,073	$25,181,672	$26,193,346	$27,245,664	$28,340,258	$29,478,828	$30,663,140	$31,895,032	$33,176,415
LARGE COMMERCIAL	$10,043,424	$10,446,919	$10,866,624	$11,303,191	$11,757,296	$12,229,646	$12,720,972	$13,232,037	$13,763,634	$14,316,588	$14,891,757	$15,490,033
LARGE COMMERCIAL & INDUSTRIAL	$6,035,124	$6,277,585	$6,529,787	$6,792,121	$7,064,995	$7,348,831	$7,644,070	$7,951,171	$8,270,609	$8,602,881	$8,948,501	$9,308,007
STREET LIGHTING AND TRAFFIC CONTROL	$745,406	$775,352	$806,502	$838,903	$872,606	$907,663	$944,129	$982,059	$1,021,513	$1,062,552	$1,105,240	$1,149,643
AGRICULTURAL	$570,782	$593,713	$617,566	$642,376	$668,184	$695,028	$722,951	$751,995	$782,207	$813,632	$846,319	$880,320
SUBTOTAL - POWER SUPPLY REVENUE REQUIREMENT	$128,299,349	$133,453,775	$138,815,281	$144,392,185	$150,193,141	$156,227,150	$162,503,576	$169,032,157	$175,823,024	$182,886,714	$190,234,188	$197,876,846
IOU MELDED RATE FOR POWER SUPPLY ($/MWh)	$102.44	$106.02	$109.73	$113.57	$117.55	$121.66	$125.92	$130.33	$134.89	$139.61	$144.50	$149.56
V. CCA POWER SUPPLY REVENUE REQUIREMENT ($)												
COST OF ENERGY	$84,184,350	$85,649,273	$91,900,946	$92,534,953	$93,325,224	$96,545,813	$101,759,404	$105,783,986	$108,098,778	$110,982,046	$113,067,402	$114,604,418
CAPITAL & DEBT COVERAGE	$37,848,307	$31,789,190	$31,789,190	$31,789,190	$31,789,190	$31,789,190	$31,789,190	$31,789,190	$31,789,190	$31,789,190	$31,789,190	$31,789,190
ADMISTRATIVE & GENERAL COSTS	$6,409,760	$6,632,796	$6,862,524	$7,099,143	$7,342,861	$7,593,891	$7,852,451	$8,118,768	$8,393,075	$8,675,610	$8,966,622	$9,266,364
FRANCHISE FEES	$914,671	$919,244	$923,840	$928,459	$933,102	$937,767	$942,456	$947,168	$951,904	$956,664	$961,447	$966,254
BILLING	$1,024,786	$1,024,786	$1,024,786	$1,024,786	$1,024,786	$1,024,786	$1,024,786	$1,024,786	$1,024,786	$1,024,786	$1,024,786	$1,024,786
SUBTOTAL - CCA REVENUE REQUIREMENT	$130,381,873	$126,015,288	$132,501,286	$133,376,531	$134,415,162	$137,891,446	$143,368,286	$147,663,897	$150,257,732	$153,428,295	$155,809,447	$157,651,012
VI. REVENUES FROM MARKET SALES ($)	$474,984	$426,412	$308,505	$263,251	$223,301	$193,065	$165,828	$140,596	$110,529	$92,641	$77,487	$61,256
VII. CCA REVENUE REQUIREMENT - NET MARKET SALES ($)	$129,906,889	$125,588,876	$132,192,780	$133,113,280	$134,191,860	$137,698,380	$143,202,459	$147,523,301	$150,147,204	$153,335,655	$155,731,960	$157,589,756
VIII. CCA MELDED RATE FOR POWER SUPPLY ($/MWh)	$103.72	$99.77	$104.50	$104.70	$105.03	$107.23	$110.97	$113.75	$115.19	$117.05	$118.29	$119.11

Appendix B – Energy Efficiency Potential in the Marin Communities

Section 1 – Introduction

1.1 Overview

This report supports Marin's planning efforts to implement a Community Choice Aggregation (CCA) program within its proposed service territory. Demand-side resources form a part of the CCA's resource portfolio, consistent with the treatment of energy-efficiency and demand-side management alternatives within the resource portfolios of California's major investor-owned electric utilities (IOU). This energy efficiency potential forecast serves as a means to estimate the scope and types of energy efficiency programs Marin might include within its resource portfolio within the following customer segments:

Residential – Low-Income and Multi-Family
Residential
Commercial/Small Commercial
Large Commercial/Industrial

Preliminary program planning is prepared based on the conduct of an energy efficiency forecast that employs key assumptions and methodologies adopted by IOUs, tailored to Marin's service territory weather, demographics, and commercial and industrial customer base. The forecast identifies the size and characteristics of customer market segments, energy efficiency technology options, and projects the costs and benefits associated with forecast program achievable energy efficiency potential.

As related above, the forecast cites program achievable energy efficiency impacts within the Marin customer base. How these impacts are achieved would be based upon how programs are planned, implemented and verified by the serving distribution utility, PG&E, or by the CCA Program, consistent with CCA enabling legislation.

1.2 Approach

The method used for estimating potential is a "bottom-up" approach in which energy efficiency costs and savings are assessed at the customer segment and energy-efficiency measure level. Cost-effective program savings potential is estimated as a function of measure economics, rebate levels, and program marketing and education efforts.

1.3 Study Scope

This energy efficiency potential forecast prepared for Marin's service territory and assesses electric energy efficiency potential in the residential, commercial and industrial sector existing construction markets. This market includes both retrofit and replace-on-burn-out measures; it explicitly excludes new construction and major renovation markets. The study assesses achievable potential savings over the near-term and is restricted to energy efficiency measures and practices that are presently commercially available. In addition, this study is focused on measures that could be relatively easily substituted for or applied to existing technologies on a retrofit basis. As a result, measures and savings that might be achieved through integrated redesign of existing energy-using systems, as might be possible during major renovations or remodels, are not included.

The scope of the forecast focuses on cost-effective programs that can be planned and implemented to yield the maximum efficiency gains in the near-term. As shown in the following table, 85 percent of energy efficiency potential resides in existing building retrofit programs for residential, commercial and industrial customers.[33]

Table 1-3 Energy Efficiency Market Potential

Existing Residential	53.0%
Existing Commercial	18.0%
Existing Industrial	14.0%
Residential New Construction	1.0%
Commercial New Construction	6.0%
Industrial New Construction	1.0%
Emerging Technologies	7.0%

1.4 Report Organization

The remainder of this report is organized as follows:

Section 2 presents forecast methods and scenario assumptions

Section 3 cites report information sources

Attachment A – Sector Energy Efficiency Measures

Attachment B – Industrial Sector Incentive Percentages of Measure Costs

Attachment C – Avoided Cost Assumptions

Section 2 – Methods and Scenario Assumptions

This forecast applies information taken from a variety of sources listed under Section 3 Sources below.

2.1 Defining Energy Efficiency Potential

Energy efficiency potential studies were popular throughout the utility industry from the late 1990s through the mid-1990s. This period coincided with the advent of what was called least-cost

California Energy Efficiency Potential, Study Volume 1, California Measurement Advisory Council (CALMAC) Study ID: PGE0211.01, May 24, 2006, Figure 12-2: Distribution of Electric Energy Market Potential, Existing Incentive Levels through 2016 or integrated resource planning. Energy efficiency potential studies became one of the primary means of characterizing the resource availability and value of energy efficiency within the overall resource planning process.

This study defines several different types of energy efficiency potential: namely, technical, economic and achievable program. These potentials are described below:

Technical potential, defined as the complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective.
Economic potential, defined s the technical potential of those en energy-efficiency measures that are cost-effective when compared to supply-side alternatives.
Achievable program potential, the amount of savings that would occur in response to specific program funding and measure incentive levels

Naturally occurring potential is the amount of savings estimated to occur as result of normal market forces absent programmatic intervention. For the purposes of this forecast prototypical net-to-gross ratios[34,35] were used to account for naturally occurring measure adoption and program free-ridership as follows:

Residential: 80 percent (all other residential programs)
Commercial: 80 percent (all other nonresidential programs)
Industrial: 80 percent (all other nonresidential programs)

2.2 Summary of Analytical Steps

This energy efficiency forecast was performed on the conduct of a number of basic analytical steps to produce estimates of the energy efficiency potentials introduced above. The key analytical steps conducted are:

Step 1: Develop Initial Input Data
Step 2: Estimate Technical Potential
Step 3: Estimate Economic Potential and Supply Curves
Step 4: Estimate Achievable Program Potential

Step 1: Develop Initial Input Data

Development of Measure List (Attachment A)

<u>Residential Sector</u>: The list of measures was developed by starting with measures included in the referenced residential sector energy efficiency potential study.[36] Two major changes were incorporated into this initial list of measures: (1) Compact Fluorescent Lamp (CFL) types and sizes were expanded from three generic CLF applications to eight, varying by ranges of wattage

[34] Rulemaking 01-08-028, Decision 05-04-051, Attachment 3 – Energy Efficiency Policy Manual – Version 3, CPUC, April 2005
[35] E3 program cost-effectiveness calculator version 3b5
[36] California Statewide Residential Sector Energy Efficiency Potential Study, KEMA-XENERGY, April 2003

and fixture configuration, and (2) heating ventilation and air conditioning measure efficiencies were adjusted to align with new the new federal efficiency standards.[37]

Commercial Sector: The list of commercial sector measures were developed by reconciling the list of measures presented in two key commercial sector potential studies[38] updated to reflect new federal efficiency standards.[39]

Industrial Sector: Industrial sector measure data were provided by Lawrence Berkeley National Laboratories as presented in a recently completed industrial sector energy efficiency potential forecast.[40]

Gather and Develop Measure Technical Data (costs and savings) on efficient measure opportunities.[41]

Gather, Analyze and Develop Building Characteristics: Information includes such building characteristics as number of households, building type square footage, and electricity consumption and intensity by end use, end-use consumptive load patterns, market shares of baseline efficiency electric consuming equipment, and market shares of energy efficient technologies and practices.[42]

Step 2: Estimate Technical Potential

Estimating Technical Potential is accomplished using the following core equation:

$$\text{Measure Technical Potential} = \text{Total Square Feet} \times \text{Base Case Equipment EUI kWh/ft2} \times \text{Applicability Factor} \times \text{Incomplete Factor} \times \text{Feasibility Factor} \times \text{Savings Factor}$$

where:

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37 10 CFR 430.32 Residential Air Conditioners and Heat Pumps and 10 CFR 431.97 Commercial Minimum Cooling and Heating Efficiency Standards

38 SW039A California Statewide commercial Sector Energy Efficiency Potential Study, Xenergy, May 2003 and PGE0252.01 California Energy Efficiency Potential Study, Itron, May 2006

39 Ibid (footnote 3)

40 PGE0252.01 California Industrial Existing Construction Energy Efficiency Potential Study, KEMA, May 2006

41 2004-2005 Database for Energy Efficient Resources, Version 2.01, California Public Utilities Commission (CPUC) and California Energy Commission, November 2005 – Certain measure savings, i.e., lighting measures were derived using segment specific engineering calculations

42 Household percentages for age and type are derived from 2000 US Census escalated through 2005 using a CAGR of 3.78 percent and applied to County's residential customer count; commercial floor space is projected using segment whole building energy intensity in kWh/ft^2 are from CEC-0400-2005-036 Energy Demand Forecast, California Energy Commission, June 2005 and Manufacturing Energy Consumption Survey (MECS), US DOE EIA, 2002; baseline market shares, energy efficiency technologies market shares and equipment densities are taken from energy efficiency potential studies (Section 7 Sources); lighting technology densities were create based on activity specific foot candle and lighting power density requirements.

Square Feet: The total floor space for all buildings in the market segment. For residential analysis the number of dwelling units is substituted for square feet.
Base-case Equipment Energy Usage Intensity (EUI): The energy use per square foot by each base-case technology in the market segment. This is the consumption of the energy-using equipment that the efficient technology replaces or affects.
Applicability Factor: The fraction of floor space (or dwelling units) that is applicable for the efficient technology in a given market segment.
Incomplete Factor: The fraction of applicable floor space (or dwelling units) that is *not yet converted* to the efficient measure (1.0 minus the fraction of floor space that already has the energy efficiency measure installed).
Feasibility Factor: The fraction of the applicable floor space (or dwelling units) that is technically feasible for conversion to the efficient technology from an engineering perspective.
Savings Factor: The reduction in energy consumption resulting from application of the efficient technology.

Step 3: Estimate Economic Potential and Supply Curves

Economic Potential: As introduced in Section 2.2 *economic potential* is the technical potential of those energy conservation measures that are cost effective when compared to supply-side alternatives. The Total Resource Cost (TRC) test[43] is applied to assess cost effectiveness. Expressed as a benefit cost ratio, measure benefits are divided by program and participant costs, and must yield a ratio greater than 1.0 to be considered *cost-effective*. Benefits are the net present value of avoided supply costs (Avoided Cost Assumptions, see Attachment C). Incentives are treated as *transfer* payments and are not considered in the TRC cost test.

Energy Efficiency Supply Curves: Energy efficiency supply curves graph the amount of savings that could be achieved at each level of cost, built up across individual measures. Efficiency measures are sorted on a least-cost basis, total savings are calculated incrementally with respect to measures that precede them. Supply curves typically reflect diminishing returns, i.e., costs increase rapidly and savings decrease toward the end of the curve. Supply curves help to answer the question "How much savings can be achieved, at what cost, by implementing which measures?"

Step 4: Estimate Achievable Program Potential

Energy efficiency potential studies (Section 3 Sources) employ varying methods to predict program participation rates. This forecast adopts the assumption that program funding is tied to customer awareness and willingness to adopt. Under this reasoning consumer awareness is linked to marketing budgets and willingness to adopt is linked to incentives that offset the incrementally higher cost of energy efficient technologies.

Estimating achievable program potential is accomplished by applying a series of screens. First, the applicability factor, incomplete factor and feasibility factor are applied to render economic potential *eligible stock* (residential dwellings or commercial floor space). Second, awareness is

[43] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects – Chapter 4, CPUC, October 2001, Chapter 4, page 18

considered and the *unaware* consumer associated building stock is removed. Third, adoption is calculated as a function of the Participant Cost Test. [44]

Consumer Awareness Screen: This forecast treats *lack of* consumer awareness as a market barrier to adoption and applies a 25 percent assumption of awareness to impose realistic limits on forecast market potential. This approximation was adopted in both SW039A California Statewide Commercial Sector energy Efficiency Study, Xenergy, July 2002 (2002 study) and PGE0211.01 California Energy Efficiency Potential Study, Itron May 2006 (2004 study).[45]

Participant Cost Test Screen: The participant cost test is the measure of quantifiable benefits and costs to the customer due to participation in a program. Benefits of participation in a demand-side program include the reduction in the customer's utility bill, any incentive paid by the utility and any tax credit received. Costs of participation are all out-of-pocket expenses incurred as result of participating in the program. Results of the test are expressed in four ways: net present value per average participant, net present value for the total program, a benefit-cost ratio, and discounted payback period (years).

Energy efficiency forecasts (Sources Section 3) apply either the benefit-cost ratio or the payback period as the final screen to project customer adoption. The benefit-cost ratio is the ratio of total benefits of a program to the total costs. The payback period is the number of years it takes until the cumulative benefits equal the costs. Both benefit-cost ratio and payback period methods yield acceptance curves where consumer probability to participate are projected. This forecast applies the payback period method consistent with the most recent major energy efficient forecast for residential, commercial and industrial customer sectors.[46]

2.3 Planning Scenario – Base Assumptions

Because achievable potential depends on the type and degree of intervention applied, potential estimates typically include alternative funding scenarios. Given the scope and time-frame, the forecast was constrained to a single achievable program scenario based on historic program funding of similar programs[47].

The following table summarizes the baseline planning scenario assumptions adopted:

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[44] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, CPUC, October 2001, Chapter 2, page 8

[45] PGE0211.01 California Energy Efficiency Potential Study, Itron May 2006, page 3-21 Approach and key Assumptions "The 2002 study assumes that awareness is 25 percent . . .this is the same as the 2004 study assuming that the original level of awareness and willingness was 62.5%."

[46] PGE0211.01 California Energy Efficiency Potential Study, Itron, May 2006

[47] The base achievable funding scenario is tied to program budget levels similar to California 2004-2005 energy efficiency programs. Incentive dollars are estimated directly in REEP as a function of predicted adoptions. Model inputs include the percentage of incremental measure cost paid as well as proportional program budget allocations to administration and marketing functions.

Table 2-1 Baseline Planning Scenario Assumptions

Sector	Measure Category	Incentive percent Measure Cost	Program Cost - Administration	Program Cost Incentives
Residential[48]	All	33%	20%	80%
Commercial	Lighting	32.6%	20%	80%
	HVAC	45.8%	20%	80%
	Refrigeration	60.9%	20%	80%
	Office Equip.	50.0%	20%	80%
Industrial[49]	125 Measures	Variable	52.6%	47.4%
		Attachment B		

Administration program cost include marketing costs

2.4 Determination of Cost-Effective Programs

Measure cost-effectiveness as described in Section 2.2, Summary of Analytical Steps - Step 3, economic potential is defined by the Total Resource Cost (TRC) test measuring the net-present-value of the avoided cost of supply against program costs (less incentive payments) plus participants' costs.

Provided below are residential achievable energy efficiency program potential annual program cost, net-present-value of the associated avoided cost of supply, TRC test cost-benefit ratio, PAC test cost-benefit ratio and levelized cost calculated as prescribed in the California Standard Practice Manual (SPM).

Upon finalizing program designs Marin should perform sensitivity analyses testing the effects, among other things, of varying funding incentive/marketing levels; perform the Ratepayer Impact (RIM) cost tests and present Participant Cost Test results at the program aggregate level (not usually done), as appropriate. The Participant Cost Test was applied within this forecast to project customer participation.

The SPM states[50] "A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g., environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate." At the same page the SPM also states "The benefits calculated in the Total Resource Cost Test are the avoided costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction."

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[48] Source: PG&E 2004 EE Program Annual Report, May 2005, Table TA 2.1, Program Cost Estimate for Cost-Effectiveness, Residential Program Area

[49] PGE0252.01 California Industrial Existing Construction Energy Efficiency Potential Study\, KEMA, May 2006

[50] SPM Chapter 4, Total Resource Cost Test Definition, page 18

Upon selection or final program designs, hourly time-of-use impacts should be applied to render TRC measurements that include transmission and distribution load reductions. Additionally, at that time, beneficial environmental impacts (externalities) can be included to render Societal Test results identified as a secondary cost-effectiveness test under the Docket. For the purposes of this analysis prototypical transmission and distribution avoided cost amounts and externality values have been incorporated as a proxy to demonstrate their relative magnitude. Sector costs and benefits, and statement of cost-effectiveness, are provided below with and without these prototypical transmission, distribution and externality additions.

Sources

Energy Efficiency Potential Studies

- SW063 California Statewide Residential Energy Efficiency Potential Study, KEMA-Xenergy, April 2003
- SW039A California Statewide Commercial Sector Energy Efficiency Potential Study, Xenergy, July 2002 (May/203)
- PGE0252.01 California Industrial Existing Construction Energy Efficiency Potential Study\, KEMA, May 2006
- PGE0211.01 California (Residential/Commercial/Industrial) Energy Efficiency Potential Study, Itron, May 24, 2006

Saturation Studies

- California Commercial End-Use Survey, Itron March 2006
- CEC-400-2006-009 California Statewide Residential Appliance Saturation Study Update, KEMA-Xenergy, June 2006

Measurement and Evaluation Studies:

- SW205.1 2003 Statewide Express Efficiency Program, Quantum Consulting, March 2005 (CFL/Ltg Op hours)

Other

- CEC-0400-2005-036 Energy Demand Forecast, California Energy Commission, June 2005
- ASHRAE/IESNA 90.1-2004, American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc.(ASHRAE) / Illuminating Engineering Society of North America (IESNA) Building Type LPD Values
- Manufacturing Energy Consumption Survey (MECS), US DOE EIA, 2002
- No. 81, Supplement No. 2, Annual Degree Days to Selected Bases, United States Climate Normals, US Department of Commerce, National Oceanic and Atmospheric Administration, 1971-2000
- U.S. Census Bureau, County and City Data Book, Table C-7. Cities - Government Finances and Climate, 2000
- Application 05-06-004, Errata to Pacific Gas and Electric Company's Prepared Testimony and Program Descriptions Work Papers, PG&E, June 2005
- CEC-400-2006-015 California Code of Regulations, Title 24 - 2005 Building Energy Efficiency Standards, California Energy Commission, October 2005
- CEC-400-2006-REV1 California Code of Regulations, Title 20 Appliance Efficiency Regulations, California Energy Commission, July 2006
- 10 Code of Federal Regulations (CFR) 430.32 Residential Air Conditioners and Heat Pumps, September 2006
- 10 CFR 431.97 Commercial Minimum Cooling and Heating Efficiency Standards , September 2006
- R.06-04-010, D.06-06-063, California Public Utilities Commission Load Shape Update Initiative Final Report, KEMA, November

2006
Revised/Updated Estimated [Energy Efficiency Measure] Useful Lives Based on Retention and Persistence Studies Results, SERA-Quantec, July 2005
2004-2005 Database for Energy Efficient Resources, Version 2.01, California Public Utilities Commission (CPUC) and California Energy Commission, November 2005
California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, CPUC, October 2001
R.01-08-028, D. 05-04-051, Attachment 3 - Energy Efficiency Policy Manual - Version 3, CPUC, April 2005
IESNA Handbook, 8th Edition, August 1995

Residential Measure Description

Base, 13 SEER Split-System Air Conditioner
14 SEER Single-Packaged/Split-System A/C & Pumps
15 SEER Single-Packaged/Split-System A/C & Pumps

A/C Thermal Expansion Valves
Programmable Thermostat (0.4)
Ceiling Fans
Whole House Fans
Attic Venting
Basic HVAC Diagnostic Testing And Repair
Duct Repair (0.32)
Duct Insulation (.4)
Cool Roofs
Window Film
Default Window With Sunscreen
Double Pane Clear Windows to Double Pane, Med Low-E
Ceiling R-0 to R-19 Insulation Blown-in (.29)
Ceiling R-19 to R-38 Insulation Blown in (.27)
Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)
Infiltration Reduction (0.4)

Resistance Space Heating
Heat Pump Space Heater
Programmable Thermostat
Ceiling R-0 to R-19 Insulation Blown-in
Ceiling R-19 to R-38 Insulation Blown-in
Floor R-0 to R-19 Insulation-Batts
Wall 2x4 R-0 to Blow-In R-13 Insulation

Base Room Air Conditioner
HE Room Air Conditioner - SEER 10.3
Direct Evaporative Cooler
Programmable Thermostat (0.4)
Ceiling Fans
Whole House Fans
Attic Venting
Basic HVAC Diagnostic Testing And Repair
Cool Roofs
Window Film
Default Window With Sunscreen
Double Pane, Med Low-E Windows
Ceiling R-0 to R-19 Insulation Blown-in (.29)
Ceiling R-19 to R-38 Insulation Blown in (.27)
Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)
Infiltration Reduction

Lighting
9-12W CFL Screw-in
13-17W CFL Screw-in
18-22W CFL Screw-in
18-22W CFL Hard-wire
23-26W CFL Screw-in
23-26W CFL Hard-wire
26-50W CFL Screw-in
26-50W CFL Hard-wire

Base Refrigerator
HE Refrigerator - Energy Star
Refrigerator - Early Replacement

Base Freezer
HE Freezer

Base 40 gal. Water Heating (EF=0.88)
Heat Pump Water Heater (EF=2.9)
HE Water Heater (EF=0.93)
Solar Water Heat
Low Flow Showerhead
Pipe Wrap
Faucet Aerators
Water Heater Blanket

Base Clothes washer (EF=1.18)
Energy Star CW (EF=2.5)
SEHA CW Tier 2 (EF=3.25)

Base Clothes Dryer (EF=.46)
HE Clothes Dryer (EF=.52)

Base Dishwasher (EF=0.46)
Energy Star DW (EF=0.58)

Base Pool Pump
High Efficiency Pool Pump and Motor

Commercial Measure Description

Lighting
10W CFL Screw-in, Base 40W Incandescent (Inc)
10W CFL Hardwired, Base 40W Inc
15W CFL Screw-in, Base 60W Inc
15W CFL Hardwired, Base 60W Inc
20W CFL Screw-in, Base 75W Inc
20W CFL Hard-wire, Base 75W Inc
38W CFL Screw-in, Base 120W Inc
38W CFL Hard-wire, Base 120W Inc
Interior Metal Halide 70W, Base 200W Inc
Interior Metal Halide 100W, Base 300W Inc
Interior Metal Halide 175W, Base 500W Inc
Interior Metal Halide 250 W, Base 750W Inc
Exterior Pulse Start Metal Halide 100W, Base 300W Inc
Exterior Pulse Start Metal Halide 175W, Base 500W Inc
Exterior Pulse Start Metal Halide 250W, Base 700W Inc
HE T8 or T5 fixtures w/ Elec Ballast (4Ft) Fixture
T8 Lamps, 2nd Gen Elec Ballast (8Ft) Fixture
14W CFL Reflector - Screw-in, Base as 60W Inc
Interior HID fixture 36-70 W (merc. vapor base case)
Interior HID fixture 71-100W (merc. vapor base case)
Interior HID fixture 101-175 W (merc. vapor base case)
Exterior 100W MH (merc. vapor base case)
Exterior Pulse Start MH 175W> (merc. vapor base case)
Exterior Pulse Start 250W MH (400W merc. vapor base)
Interior HID fixture 176-250 W (merc. vapor base case)
Interior Metal Halide (Pulse Start) Fixture
HO T5 4-lamp Hi-Bay fixture
Photocell control
Time clock control
Photocell/Time clock Control (400W merc. vapor base)
Electronic ballast, dimming (w/daylighting)
LED Exit signs
Occupancy Sensor - Motion Sensor - Retrofit
Occupancy Sensor - Plug Load
Reflectors with Delamping, (4-foot lamp removed)
Reflectors with Delamping, (8-foot lamp removed)

Space Cooling
Single Package AC <65 kBtuh, SEER 14 - Base SEER 13
Split-System AC <65 kBtuh, SEER 14 - Base SEER 13
SS/SP AC & HP 65-135 kBtuh, EER 12.0 - Base EER 10.1
SS/SP AC & HP 135-240 kBtuh, EER 12.0 - Base EER 9.7
SS/SP AC & HP 240-760 kBtuh, EER 14.0 - (W/C) Base EER 10.1
SS/SP AC & HP >760 kBtuh, EER 10.8 - Base EER 9.3
HE Chiller - 0.51 kW per Ton, 500 Tons, Base 5.8 kW/Ton
Cooling Cir. Pumps - VSD
Cool Roof (Chiller)
Cool Roof (DX)
Reflective Window Film - Single Pane - Retrofit (base chiller)
Reflective Window Film - Single Pane - Retrofit (base DX)
Programmable Thermostat
DX Tune Up / Advanced Diagnostics
Chiller Tune Up / Diagnostics
Evaporative Pre-Cooler (DX)

Ventilation
Fan Motor, 5 HP, 1800 rpm, 89.5%
Variable Speed Drive Control, 5 HP
Fan Motor, 15 HP, 1800 rpm, 92.4%
Variable Speed Drive Control, 15 HP
Fan Motor, 40 HP, 1800 rpm, 94.1%
Variable Speed Drive Control, 40 HP

Office Equipment
Power management enabling
Purchase LCD monitor
Network power management enabling
Power management enabling
External hardware control
Nighttime shutdown

Refrigeration
Replace single line compress syst w a multiplex system
Permanent-split capacitor (PSC) evaporator fan motor
Electronically commutated (ECM) evaporator fan motor
Efficient low temperature compressor with EER of >= 5.2
Efficient condenser added to standard multiplex system
Elec comm (ECM) evaporator fan motor for walk-ins
Anti-Sweat Heater Controls - low temp glass door cases
New glass doors wECM fan motors, T8 lamps and elec ballasts
New glass doors wECM fan motors, T8 lamps and elec ballasts
Floating head pressure controller - multiplex compress
Night Covers for horizontal display case
Night Covers for vertical display case
Install strip curtails on doorways of walk-ins
Evap fan motor controller for walk-in coolers

Industrial Measure Description

Compressed Air
Compressed Air-O&M
Compressed Air - Controls
Compressed Air - System Optimization
Compressed Air- Sizing
Comp Air - Replace 1-5 HP motor
Comp Air - ASD (1-5 hp)
Comp Air - Motor practices-1 (1-5 HP)
Comp Air - Replace 6-100 HP motor
Comp Air - ASD (6-100 hp)
Comp Air - Motor practices-1 (6-100 HP)
Comp Air - Replace 100+ HP motor
Comp Air - ASD (100+ hp)
Comp Air - Motor practices-1 (100+ HP)
Power recovery
Refinery Controls
Energy Star Transformers

Pumps
Pumps - O&M
Pumps - Controls
Pumps - System Optimization
Pumps - Sizing
Pumps - Replace 1-5 HP motor
Pumps - ASD (1-5 hp)
Pumps - Motor practices-1 (1-5 HP)
Pumps - Replace 6-100 HP motor
Pumps - ASD (6-100 hp)
Pumps - Motor practices-1 (6-100 HP)
Pumps - Replace 100+ HP motor
Pumps - ASD (100+ hp)
Pumps - Motor practices-1 (100+ HP)
Power recovery
Refinery Controls
Energy Star Transformers

Fans
Fans - O&M
Fans - Controls
Fans - System Optimization
Fans- Improve components
Fans - Replace 1-5 HP motor
Fans - ASD (1-5 hp)
Fans - Motor practices-1 (1-5 HP)
Fans - Replace 6-100 HP motor
Fans - ASD (6-100 hp)
Fans - Motor practices-1 (6-100 HP)
Fans - Replace 100+ HP motor
Fans - ASD (100+ hp)
Fans - Motor practices-1 (100+ HP)
Optimize drying process
Power recovery
Refinery Controls
Energy Star Transformers

Lighting
RET 2L4' Premium T8, 1EB
CFL Hardwired, Modular 36W
Metal Halide, 50W
Occupancy Sensor, 4L4' Fluorescent Fixtures
Energy Star Transformers

Other Processes
Other Process Controls (batch + site)
Efficient desalter
New transformers welding
Efficient processes (welding, etc.)
Process control
Power recovery
Refinery Controls
Energy Star Transformers

Drives
Bakery - Process (Mixing) - O&M
O&M/drives spinning machines
Air conveying systems
Replace V-Belts
Drives - EE motor
Gap Forming paper machine
High Consistency forming
Optimization control PM
Efficient practices printing press
Efficient Printing press (fewer cylinders)
Light cylinders
Efficient drives
Clean Room - Controls
Clean Room - New Designs
Drives - Process Controls (batch + site)
Process Drives - ASD
O&M - Extruders/Injection Molding
Extruders/injection Molding-multipump
Direct drive Extruders
Injection Molding - Impulse Cooling
Injection Molding - Direct drive
Efficient grinding
Process control
Process optimization
Drives - Process Control
Efficient drives - rolling
Drives - Optimization process (M&T)
Drives - Scheduling
Machinery
Efficient Machinery
Energy Star Transformers

Other
Replace V-belts
Membranes for wastewater
Energy Star Transformers

Heating
Bakery - Process
Drying (UV/IR)
Heat Pumps - Drying
Top-heating (glass)
Efficient electric melting
Intelligent extruder (DOE)
Near Net Shape Casting
Heating - Process Control
Efficient Curing ovens
Heating - Optimization process (M&T)
Heating - Scheduling
Energy Star Transformers

Refrigeration
Efficient Refrigeration - Operations
Optimization Refrigeration
Energy Star Transformers

Space Cooling
DX Packaged System, EER=10.3, 10 tons
DX Tune Up/ Advanced Diagnostics
DX Packaged System, EER=10.9, 10 tons
Window Film - DX
Evaporative Pre-Cooler
Prog. Thermostat - DX
Cool Roof - DX
Energy Star Transformers

Centrifugal Chillers
Centrifugal Chiller, 0.51 kW/ton, 500 tons
Window Film - Chiller
EMS - Chiller
Cool Roof - Chiller
Chiller Tune Up/Diagnostics
Cooling Circ. Pumps - VSD
Energy Star Transformers

ATTACHMENT B – INDUSTRIAL MEASURE INCENTIVE AMOUNTS

APPENDIX C - INDUSTRIAL MEASURE INCENTIVE AMOUNMTS

Measure #	Measure Description	Percent Incremental Cost	Measure #	Measure Description	Percent Incremental Cost	Measure #	Measure Description	Percent Incremental Cost
100	Base Compressed Air	0%	400	Base Drives	0%	603	New transformers welding	60%
101	Compressed Air-O&M	47%	401	Bakery - Process (Mixing) - O&M	47%	604	Efficient processes (welding, etc.)	60%
102	Compressed Air - Controls	60%	402	O&M/drives spinning machines	47%	605	Process control	50%
103	Compressed Air - System Optimization	60%	403	Air conveying systems	60%	606	Power recovery	47%
104	Compressed Air- Sizing	60%	404	Replace V-Belts	60%	607	Refinery Controls	50%
105	Comp Air - Replace 1-5 HP motor	20%	405	Drives - EE motor	60%	608	Energy Star Transformers	40%
106	Comp Air - ASD (1-5 hp)	20%	406	Gap Forming papermachine	60%	700	Base Centrifugal Chiller, 0.58 kW/ton, 500 tons	0%
107	Comp Air - Motor practices-1 (1-5 HP)	60%	407	High Consistency forming	60%	701	Centrifugal Chiller, 0.51 kW/ton, 500 tons	47%
108	Comp Air - Replace 6-100 HP motor	40%	408	Optimization control PM	40%	702	Window Film - Chiller	47%
109	Comp Air - ASD (6-100 hp)	60%	409	Efficient practices printing press	60%	703	EMS - Chiller	47%
110	Comp Air - Motor practices-1 (6-100 HP)	60%	410	Efficient Printing press (fewer cylinders)	60%	704	Cool Roof - Chiller	47%
111	Comp Air - Replace 100+ HP motor	60%	411	Light cylinders	60%	705	Chiller Tune Up/Diagnostics	47%
112	Comp Air - ASD (100+ hp)	60%	412	Efficient drives	60%	706	Cooling Circ. Pumps - VSD	47%
113	Comp Air - Motor practices-1 (100+ HP)	60%	413	Clean Room - Controls	40%	707	Energy Star Transformers	40%
114	Power recovery	60%	414	Clean Room - New Designs	60%	710	Base DX Packaged System, EER=10.3, 10 tons	0%
115	Refinery Controls	40%	415	Drives - Process Controls (batch + site)	50%	711	DX Tune Up/ Advanced Diagnostics	47%
116	Energy Star Transformers	40%	416	Process Drives - ASD	60%	712	DX Packaged System, EER=10.9, 10 tons	47%
200	Base Fans	0%	417	O&M - Extruders/Injection Moulding	47%	713	Window Film - DX	47%
201	Fans - O&M	47%	418	Extruders/Injection Moulding-multipump	60%	714	Evaporative Pre-Cooler	47%
202	Fans - Controls	40%	419	Direct drive Extruders	60%	715	Prog. Thermostat - DX	47%
203	Fans - System Optimization	60%	420	Injection Moulding - Impulse Cooling	60%	716	Cool Roof - DX	47%
204	Fans- Improve components	60%	421	Injection Moulding - Direct drive	60%	717	Energy Star Transformers	40%
205	Fans - Replace 1-5 HP motor	20%	422	Efficient grinding	60%	800	Base Lighting	0%
206	Fans - ASD (1-5 hp)	20%	423	Process control	40%	801	RET 2L4' Premium T8, 1EB	47%
207	Fans - Motor practices-1 (1-5 HP)	60%	424	Process optimization	40%	802	CFL Hardwired, Modular 36W	47%
208	Fans - Replace 6-100 HP motor	40%	425	Drives - Process Control	40%	803	Metal Halide, 50W	47%
209	Fans - ASD (6-100 hp)	60%	426	Efficient drives - rolling	60%	804	Occupancy Sensor, 4L4' Fluorescent Fixtures	47%
210	Fans - Motor practices-1 (6-100 HP)	60%	427	Drives - Optimization process (M&T)	50%	805	Energy Star Transformers	47%
211	Fans - Replace 100+ HP motor	60%	428	Drives - Scheduling	47%	900	Base Other	0%
212	Fans - ASD (100+ hp)	60%	429	Machinery	60%	901	Replace V-belts	47%
213	Fans - Motor practices-1 (100+ HP)	60%	430	Efficient Machinery	60%	902	Membranes for wastewater	47%
214	Optimize drying process	60%	431	Energy Star Transformers	40%	903	Energy Star Transformers	40%
215	Power recovery	60%	500	Base Heating	0%			
216	Refinery Controls	40%	501	Bakery - Process	60%			
217	Energy Star Transformers	40%	502	Drying (UV/IR)	60%			
300	Base Pumps	0%	503	Heat Pumps - Drying	60%			
301	Pumps - O&M	47%	504	Top-heating (glass)	60%			
302	Pumps - Controls	40%	505	Efficient electric melting	60%			
303	Pumps - System Optimization	60%	506	Intelligent extruder (DOE)	60%			
304	Pumps - Sizing	60%	507	Near Net Shape Casting	60%			
305	Pumps - Replace 1-5 HP motor	20%	508	Heating - Process Control	50%			
306	Pumps - ASD (1-5 hp)	20%	509	Efficient Curing ovens	60%			
307	Pumps - Motor practices-1 (1-5 HP)	60%	510	Heating - Optimization process (M&T)	60%			
308	Pumps - Replace 6-100 HP motor	40%	511	Heating - Scheduling	50%			
309	Pumps - ASD (6-100 hp)	60%	512	Energy Star Transformers	40%			
310	Pumps - Motor practices-1 (6-100 HP)	60%	550	Base Refrigeration	0%			
311	Pumps - Replace 100+ HP motor	60%	551	Efficient Refrigeration - Operations	60%			
312	Pumps - ASD (100+ hp)	60%	552	Optimization Refrigeration	60%			
313	Pumps - Motor practices-1 (100+ HP)	60%	553	Energy Star Transformers	40%			
314	Power recovery	60%	600	Base Other Process	0%			
315	Refinery Controls	40%	601	Other Process Controls (batch + site)	50%			
316	Energy Star Transformers	40%	602	Efficient desalter	60%			

ATTACHMENT C – AVOIDED COST ASSUMPTIONS

Avoided Cost Bases

Customer Sector	Residential			Commercial			Industrial			Composite		
	Avoided Cost Rate by TOU	2005 Energy Use	Avoided Cost TOU Amount	Avoided Cost Rate by TOU	2005 Energy Use	Avoided Cost TOU Amount	Avoided Cost Rate by TOU	2005 Energy Use	Avoided Cost TOU Amount	2005 Energy Use	Avoided Cost TOU Amount	Avoided Cost Rate by TOU
Summer On ($/kWh)	0.101444444	204,061,018	$20,700,857	0.121131383	192,530,768	$23,321,518	0.134839044	32,053,411	$4,322,051	428,645,196	$48,344,426	$0.1128
Summer Off ($/kWh)	0.068444444	116,891,027	$8,000,541	0.081727198	95,894,485	$7,837,188	0.090975741	21,208,369	$1,929,447	233,993,880	$17,767,176	$0.0759
Winter On ($/kWh)	0.084333333	234,203,777	$19,751,185	0.082717515	168,913,647	$13,972,117	0.0931875	29,025,646	$2,704,827	432,143,070	$36,428,130	$0.0843
Winter Off ($/kWh)	0.056222222	135,314,704	$7,607,693	0.05514501	85,580,953	$4,719,363	0.062125	18,954,105	$1,177,524	239,849,762	$13,504,580	$0.0563
Total		690,470,525	$56,060,276		542,919,853	$49,850,185		101,241,530	$10,133,849	1,334,631,908	$116,044,311	$0.0869
Weight Average $/kWh			$0.081			$0.092			$0.100			

PG&E energy use hourly profiles are applied to 2005 billing data to allocate energy consumption into time-of-use periods.
Sector time-of-use consumption is applied to Marin CCA sector time-of-use avoided cost rates to render estimated sector avoided cost amounts.
Customer sector time-of-use energy consumption and avoided costs amounts are combined to calculate composite time-of-use avoided cost rates.

Avoided Energy Costs

Year	Summer ON-Peak $/kWh Gen	T&D	Env. Ext.	Total	Summer Off-Peak $/kWh Gen	T&D	Env. Ext.	Total
1	0.11			0.11	0.08			0.08
2	0.12			0.12	0.08			0.08
3	0.12			0.12	0.08			0.08
4	0.12			0.12	0.08			0.08
5	0.12			0.12	0.08			0.08
6	0.13			0.13	0.09			0.09
7	0.13			0.13	0.09			0.09
8	0.13			0.13	0.09			0.09
9	0.14			0.14	0.09			0.09
10	0.14			0.14	0.09			0.09
11	0.14			0.14	0.10			0.10
12	0.15			0.15	0.10			0.10
13	0.15			0.15	0.10			0.10
14	0.16			0.16	0.10			0.10
15	0.16			0.16	0.11			0.11
16	0.16			0.16	0.11			0.11
17	0.17			0.17	0.11			0.11
18	0.17			0.17	0.12			0.12
19	0.18			0.18	0.12			0.12
20	0.18			0.18	0.12			0.12

Year	Winter On-Peak $/kWh Gen	T&D	Env. Ext.	Total	Winter Off-Peak $/kWh Gen	T&D	Env. Ext.	Total
2009	0.08			0.08	0.06			0.06
2010	0.09			0.09	0.06			0.06
2011	0.09			0.09	0.06			0.06
2012	0.09			0.09	0.06			0.06
2013	0.09			0.09	0.06			0.06
2014	0.10			0.10	0.06			0.06
2015	0.10			0.10	0.07			0.07
2016	0.10			0.10	0.07			0.07
2017	0.10			0.10	0.07			0.07
2018	0.11			0.11	0.07			0.07
2019	0.11			0.11	0.07			0.07
2020	0.11			0.11	0.07			0.07
2021	0.11			0.11	0.08			0.08
2022	0.12			0.12	0.08			0.08
2023	0.12			0.12	0.08			0.08
2024	0.12			0.12	0.08			0.08
2025	0.13			0.13	0.08			0.08
2026	0.13			0.13	0.09			0.09
2027	0.13			0.13	0.09			0.09
2028	0.13			0.13	0.09			0.09

Annual escalation 2.5 percent; energy line losses 6.7%; discount rate 7.43 percent

Appendix C – List of Acronyms and Definitions

A-1 – Bundled electric service customer class of PG&E, which refers to Small Commercial customers

A-6 – Bundled electric service customer class of PG&E, which refers to Small Commercial customers on time-of-use schedules

A-10 – Bundled electric service customer class of PG&E, which refers to Medium Commercial customers (demand is above 200 kW but less than 499 kW for three consecutive months)

A&G – Administrative and General

AB 32 – The California Global Warming Solutions Act of 2006, which provides mandates regarding future greenhouse gas emission levels in California

AB 117 – Assembly Bill 117, also known as the Community Choice Aggregation Law or CCA legislation

AB 1890 – Assembly Bill 1890

ACEEE – American Council for an Energy-Efficient Economy

APT – Annual Procurement Target

AR/AP – Accounts Receivable/Accounts Payable

CAISO – California Independent System Operator

CALMAC – California Measurement Advisory Council

CARE – California Alternate Rates for Energy

CCA – Community Choice Aggregation

CEC – California Energy Commission

CO2 – Carbon Dioxide

CPUC – California Public Utilities Commission

CRS – Cost Responsibility Surcharge

CSI – California Solar Initiative

CTC – Competition Transition Charge

DG – Distributed Generation

DWR – Department of Water Resources

E-19 – Bundled electric service customer class of PG&E, which refers to Large Commercial customers (demand exceeds 499 kW for three consecutive months)

E-20 – Bundled electric service customer class of PG&E, which refers to Industrial customers (demand exceeds 999 kW for three consecutive months)

ED – Executive Director

EDI – Electronic Data Interchange

ERRA – Energy Resource Recovery Account, a balancing account utilized by PG&E to record and recover power costs associated with PG&E's authorized procurement plan, pursuant to California Public Utilities Code Section 454.5 (d)(3) and applicable CPUC Decisions

ESP – Energy Service Provider

FERC – Federal Energy Regulatory Commission

Full-Requirements Contract – A power services contract under which the supplier provides all necessary services, including power procurement, scheduling coordination, data management, ancillary services, and requisite capacity reserves as well as other functions; a "turn-key" power procurement solution

GHG – Greenhouse Gas

GRC – General Rate Case

GW – Gigawatt: One gigawatt equates to 1,000 megawatts (MW), which is enough energy to power approximately 750,000-1,000,000 average California homes
GWh – Gigawatt hour: One thousand MWhs, which is enough energy to supply the electric needs of approximately 750-1,000 typical homes
ICLEI – International Council for Local Environmental Initiatives
IOU – Investor Owned Utilities
IPP – Independent Power Producer
IPT – Incremental Procurement Target
IT – Information Technology
JPA – Joint Powers Agency
KW – Kilowatt: Enough energy to power approximately one average California home
KWh – Kilowatt hour: Smallest unit of measurement used to quantify commercial energy production
LOC – Letter of Credit
MCE – Marin Clean Energy Joint Powers Authority, a Joint Powers Agency with membership consisting of Marin County and the eleven cities within the geographic boundaries of the County
MRTU – Market Redesign and Technology Upgrade
MW – Megawatt: One megawatt equates to 1,000 kilowatts (kW), which is enough energy to power approximately 750-1,000 average California homes
MWh – Megawatt hour: One megawatt produced for a duration of one hour, which is equivalent to 1,000 kilowatt hours (kWh) – enough energy to supply the electric needs of a typical home with an electric hot water system
NCPA – Northern California Power Agency
NEM – Net Energy Metering
NOPEC – Northern Ohio Public Energy Council
NOx – Nitrogen Oxides
NP15 – North of Path 15
NTAC – Northwest Transmission Assessment Committee
O&M – Operations and Maintenance
PA – Project Agreement
PG&E – Pacific Gas and Electric Company, the incumbent electric utility serving the Marin Communities
PTC – Production Tax Credit
PUC – Public Utilities Code
PUCO – Public Utilities Commission of Ohio
PV - Photovoltaic
QF – Qualifying Facilities
RE – Renewable Energy
REC – Renewable Energy Certificate
RFB – Request for Bids
RFP – Request for Proposals
RFQ – Request for Qualifications
RPS – Renewables Portfolio Standard
RRDR – Renewable Resource Development Report
SCE – Southern California Edison Company

SDG&E – San Diego Gas and Electric Company
SEP – Supplemental Energy Payment
SJVPA – San Joaquin Valley Power Authority
SMUD – Sacramento Municipal Utility District
VEE – Verification, Editing and Estimation