<u>DRAFT REPORT</u>

MARIN – CALIFORNIA

COMMUNITY CHOICE
AGGREGATION
BUSINESS PLAN

January 2008

TABLE OF CONTENTS

ACKNOWLEDGEMENTS

The following individuals are members of the Local Government Task Force, which has contributed to the development and review of this Draft Business Plan to support the Marin Communities' CCA initiative.

Belvedere	
Barbara Morrison	Councilmember
John Telischak	Mayor
George Rodericks	City Manager
Pierce MacDonald	Planning
Corte Madera	
Melissa Gill	Mayor
Carla Condon	Councilmember
Bob Pendoley	Dir. of Planning
Tony Gokoffski	Senior Engineer
David Bracken	Town Manager
Fairfax	
Lew Tremaine	Councilmember
Larry Bragman	Mayor
Linda Kelly	Town Manager
Larkspur	
Larry Chu	Mayor
Dan Hillmer	Councilmember (Alt)
Jean Bonander	City Manager
Mill Valley	
Chris Raker	Mayor
Shawn Marshall	Councilmember
Anne Montgomery	City Manager
Eric Ericson	Finance Department
Novato	
Carole Dillon-Knutson	Mayor
Dan Keen	City Manager
Jennifer Goldfinger	Asst to City Mgr
Jim Leland	Councilmember
Ross	
Richard (Rick) Strauss	Mayor
Scott Hunter	Councilmember
Gary Broad	Town Administrator
Elise Semonian	Senior Planner
Bill Cahill	Councilmember
San Anselmo	
Barbara Thornton	Councilmember
Debbie Stutsman	Town Manager
San Rafael	
Paul Cohen	Vice Mayor
Cyr Miller	Councilmember
Linda Jackson	Principal Planner
Ken Nordhoff	City Manager
Sausalito	
Jonathan Leone	Councilmember
Herb Weiner	Councilmember
Mike Kelly	Mayor
Paul Kermoyan	Community Development
Kevin Bryant	Asst to City Mgr

Tiburon	
Paul Smith	Mayor
Jeff Slavitz	Vice Mayor
Miles Berger	Councilmember
Heidi Bigall	Interim Town Manager
Nick Nguyen	Dir. of Public Works
Peggy Curran	City Manager
MMWD	
Paul Helliker	General Manager
Cynthia Kohler	Board President
NMWD	
Dennis Rodoni	Board Member
Robert Clark	Facilities Superintendent
Chris DeGabriel	General Manager
Jack Baker	Board Member
County of Marin	
Hal Brown	Supervisor
Charles McGlashan	Supervisor
Joshua Townsend	State Assembly Member Rep
Alex Hinds	CDA
Dawn Weisz	CDA
Omar Peña	CDA
Leslie Alden	BOS
Cyno Connelly	BOS
Mattew Hymel	CAO
Alex McIntyre	CAO
Mike Lowrie	CAO
Technical Advisory Committee	
Gwen Rose	VoteSolar
Wally McOuat	HMH Energy Resources, Inc.
Ray Dracker	Center for Resource Solutions
Peter Luchetti	GFP Advisors
Sean Casey	Formerly SFPUC
Community Representatives	
Mr. Spofford	CCA for Sust. San Rafael
Sue Spofford	Sustainable San Rafael
Kiki La Porta	Sustainable San Rafael
Damon Connolly	
Peter Asmus	Stinson Solar
Edward Mainland	Environmental Ombudsman
Consultants	
Tim Rosenfeld	CDA
Jody London	Jody London Consulting
John Dalessi	Navigant Consulting, Inc.
Kirby Dusel	Navigant Consulting, Inc.

EXECUTIVE SUMMARY

Beginning in 2004, the County of Marin and the eleven cities within the county ("Marin Communities" or "Marin") initiated a process to investigate offering retail electric services to customers located within the Marin Communities through a program known as Community Choice Aggregation ("CCA").[1] Marin's primary long-term goal in offering CCA service is to achieve 100% renewable energy supply within the Marin Communities, affecting significant reductions in Greenhouse Gas Emissions (GHG) consistent with Marin's voluntary International Council for Local Environmental Initiatives (ICLEI) targets (a 15% reduction in total GHG below 1990 levels by 2020, countywide).

The CCA program was established by the legislature in 2002 (AB 117) to give cities and counties the authority to procure electricity in bulk for resale to customers within their jurisdictional boundaries. Under this CCA program, PG&E would deliver the electricity to end use customers and PG&E would continue to read the electric meters and issue monthly bills to customers enrolled in the CCA program. Unlike traditional utility service, the source of the electric supply (generation) and the price paid by customers for the generation services procured by the CCA program would be determined by the CCA. Customers would have the choice of being automatically enrolled in the program following a notification process or remaining with the incumbent utility by following the opt-out process described in the customer notices.

Marin conducted feasibility studies during 2004-2005 to identify the benefits and risks of forming CCA programs. The feasibility studies, which were subject to peer review by a team of independent, expert consultants, generally found that Marin could significantly increase its use of renewable energy while providing electric rate stability and potentially reduced electric rates over the long-term relative to PG&E. The CCA's ability to finance generation projects at low cost was identified as a key factor in being able to achieve these objectives. Following consideration of the feasibility study findings, the Marin Communities decided to jointly develop a comprehensive business plan that would address issues not included within the feasibility study scope and to confirm the study's findings in certain key respects.

This business plan presents a proposal for Marin to form a regional CCA program serving the unincorporated areas of the county as well as eleven cities located within the county's geographic boundary. The plan sets forth proposals for how a Marin CCA program would be organized, funded and operated. Highlights of the plan include:

- The County of Marin and eleven participating cities would form a new Joint Powers Agency during early 2009 (potentially earlier, depending on various requisite approvals by the county and cities), tentatively named the Marin Power Authority ("Authority") for purposes of offering CCA services to customers beginning in 2010 (subject to further refinement of this plan).

[1] The eleven cities located with the County of Marin include: Belvedere, Corte Madera, Fairfax, Larkspur, Mill Valley, Novato, San Anselmo, San Rafael, Sausalito, Tiburon and Ross.

- The Authority would negotiate contracts with third party electric suppliers to provide electricity to customers and provide other technical services required for the program under a public/private partnership model.
- The Authority would offer two distinct renewable energy supply options to program customers, reflecting differing preferences within the Marin Communities:
    - 100% renewable energy supply from resources such as wind, solar, geothermal and biomass, at a specified price premium reflective of renewable energy and related program operating costs; or
    - A graduated renewable supply option with rates equivalent to those of the incumbent utility – under this option, the Authority would initially supply 25% renewable power, increasing this supply to more than 50% by 2014.
- The Authority would continue to increase its renewable energy procurement/deliveries within the graduated renewable supply option to achieve the long-term goal of 100% renewable energy supply for the entire program subject to economic and operational constraints.
- The Authority would develop or otherwise obtain entitlements to up to 200 MW of new renewable generation by 2014, financed with tax-exempt revenue bonds.
- The Authority would leverage existing state and federal incentives to achieve a targeted deployment of at least 13 MW of distributed solar (photovoltaic) systems within its boundaries by 2019.
- The Authority would promote additional energy efficiency efforts and ultimately seek to administer all energy efficiency programs within its jurisdiction, as envisioned by AB 117.
- Through implementation of the proposed CCA Program, the Cities would cause a reduction in greenhouse gas emissions of between 302,330 and 534,369 metric tons per year by 2019, as the renewable resources procured and developed by the Authority would displace production from natural gas fueled power plants.

The financial plan and customer rate impacts presented in Chapter 4 should be considered illustrative pending incorporation of prices that will be provided by the market in a Request for Bid that will be issued around January 2009, subject to various requisite approvals by the county and cities. For the time being, information contained in the Financing Plan is based on energy prices received by other CCA programs, such as the aspiring East Bay CCA Program and the San Joaquin Valley Power Authority ("SJVPA"), from the market. While this plan provides guidelines related to many key areas of CCA operation, certain plan components will also require input from the county's and cities' legal and financial professionals, as indicated in this plan. Once the business plan is finalized and reviewed by the Marin Communities (March 2008), the county and cities will need to decide whether to proceed with formation of the JPA, which would adopt the Implementation Plan for submission to the California Public Utilities Commission as required by AB 117.

The key planning elements that are statutorily required in an Implementation Plan are addressed in this business plan. The Public Utilities Code specifies that a CCA Implementation Plan must include the following components:

- Organizational structure of the program, its operations, and funding;

- Rate setting and other costs to participants;
- Disclosure and due process in setting rates and allocating costs among participants;
- Methods for entering and terminating agreements with other entities;
- The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures;
- Termination of the Program; and
- A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

California's CCA program is relatively new, and, to date, only one CCA has registered with the California Public Utilities Commission. California's lone CCA, the SJVPA is comprised of a consortium of cities and counties in the central San Joaquin Valley. The SJVPA submitted its CCA Implementation Plan on January 29, 2007.[2] On April 30, 2007, the California Public Utilities Commission provided notice to the SJVPA certifying that its Implementation Plan contained sufficient data, as required by California Public Utilities Code Section 366.2. In addition to the SJVPA, there are several other CCA development efforts under way in San Francisco, the East Bay, West Los Angeles, and Chula Vista.

The major elements of the business plan are summarized as follows.

1. Governance and Organization

The program would be implemented by a new JPA whose Board of Directors, comprised of one elected official from each of the participating communities, would have primary responsibility for managing all aspects of the CCA program. The JPA would adopt the Implementation Plan required by the CCA legislation (AB 117) and register with the California Public Utilities Commission as a Community Choice Aggregator.

Decisions by the Authority would take place in public meetings under voting procedures defined in the Joint Powers Agreement. As currently envisioned, all votes on a particular matter will be subject to a two-tier approval process: first, any decision must be approved by a simple majority of the Directors at the Governing Board meeting; second, assuming the first requirement is reached, those Directors voting in the affirmative must constitute over 50 percent of a weighted voting percentage comprised of equal treatment of each Member's electricity requirements (expressed as a ratio of each Member's electricity requirements divided by total energy requirements of the Program) and a pro rata percentage of total membership. An alternative two-tier approval process, which weights voting based on customer accounts rather than electricity requirements, has also been included in this Business Plan.

The Authority would be established under the terms of a Joint Powers Agreement, which would institute the Authority with a broad set of powers to study, promote, develop and conduct electricity related projects and programs. The JPA agreement would specify the

[2] Revisions to SJVPA's Implementation Plan were subsequently submitted on April 27, 2007; additional revisions were filed with the CPUC on August 27, 2007.

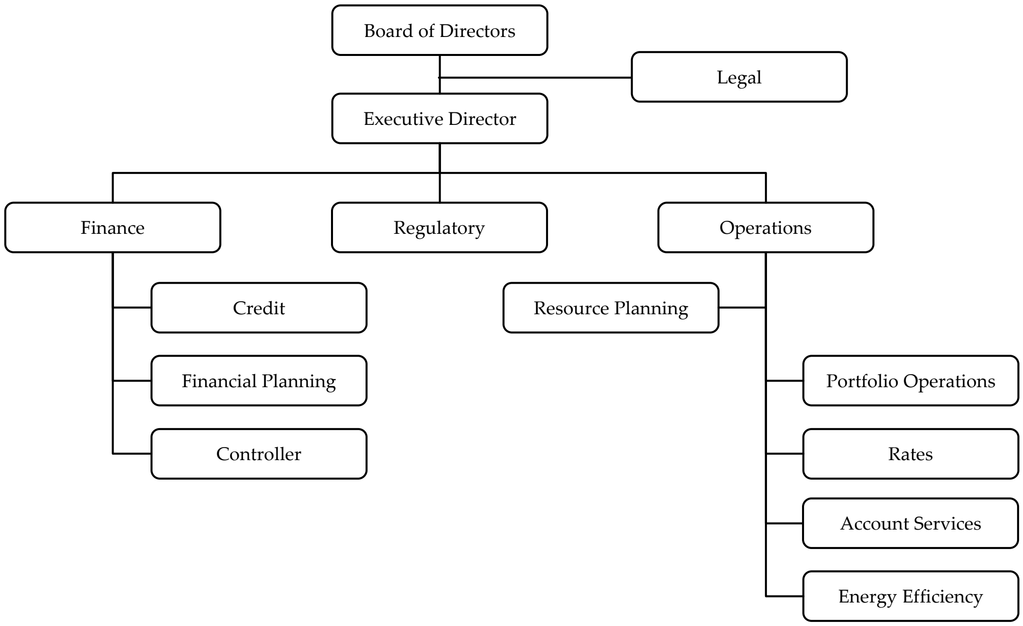
governance provisions of the Authority. Proposed principles for a JPA Agreement are discussed in Chapter 2.

The CCA program would most likely be established pursuant to a separate project agreement (Program Agreement No. 1 or PA-1) executed by and among the Authority and the members (eleven cities and Marin County). The PA-1 would transfer the members' authority under AB 117 to the Authority and authorize the initiation of CCA service to customers within the member's jurisdiction, subject to specified withdrawal rights.

Operations of the program would be the responsibility of an Executive Director, appointed by the Authority's Board of Directors. The Executive Director would manage staff, contractors and third party electric providers, in accordance with the general policies established by the Board. Because the Authority expects to commence Program operations under a full-requirements supply contract with an experienced, third-party energy supplier, the Executive Director will manage this contractual relationship to ensure performance under the contract's specified terms and conditions.[3] This organizational relationship, including functional areas for which the full-requirements supplier will be responsible is shown below in Figure 1.

[3] As a public entity, any business relationship between the Authority and a third-party contractor is assumed to result from a competitive solicitation/selection process.

Figure 1: Program Organization – Short-Term



After the Program has established itself, has identified internal staff/management to assume responsibility for necessary administrative and operational responsibilities, and has properly trained appropriate individuals to carry out their respective duties, the Authority may transition many responsibilities to internally staffed positions. Most operational responsibilities, particularly technical functions associated with managing and scheduling electric supplies and those related to retail customer settlements would be performed by a third-party contractor, likely the supplier providing service under the Authority's initial full-requirements contract.

In the event that the Authority transitions administrative and operational responsibilities to internally staffed positions, it would likely have a full time staff of approximately twenty employees to perform its responsibilities, primarily related to program and contract management, legal and regulatory, finance and accounting, energy efficiency, marketing and customer service. As previously noted, technical functions associated with managing and scheduling electric supplies and those related to retail customer settlements would be performed by an experienced third party(ies). In the longer term, these technical functions may be performed by internal staff or continue to be provided by third parties.

Staffing and contractor costs related to program startup activities are estimated at approximately $3.4 million. It is estimated that the Authority would need working capital (likely in the form of a letter of credit) in the range of $6.4 million to initiate the Program and provide the working capital needed for service to customers in Phases 1 and 2. Credit requirements may increase to as much as $15.8 million dollars for Phase 3. These figures include working capital related to power purchases that may ultimately be carried by the Program's electric supplier, subject to negotiations during the supplier selection process.

2. Phased Customer Enrollment

Service would be offered to customers in three phases, beginning with the service accounts affiliated with the members of the Authority (municipal accounts). The second phase would include the medium to large commercial and industrial customers, and the third phase would include all remaining customers. The proposed schedule for customer enrollments is shown below:

Table 1: Customer Phase-In Schedule

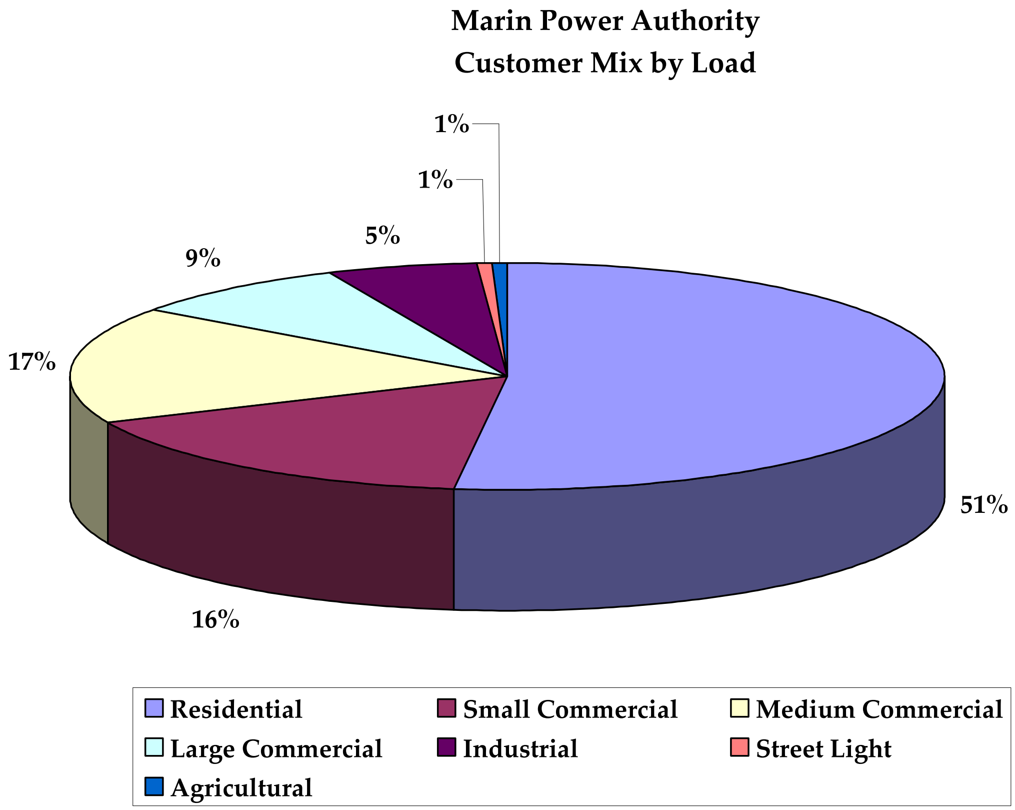
Phase	Start	Eligibility	Customer Accounts[4]
Phase 1	January 2010	Municipal Accounts	565
Phase 2	May 2010	Commercial and Industrial Accounts	1,192
Phase 3	January 2011	All Others	109,344

The phasing schedule enables the Authority and third party electricity suppliers to make any adjustments that may be necessary to ensure the program is operating effectively. It would also allow for any potential billing, settlement or cash flow problems to be addressed while the actual number of accounts and revenue requirements are small relative to full scale operations. The Authority's Board of Directors would have final authority for initiating service to Phase 1 customers and to approve transitioning from one phase to the next.

At full implementation in 2011, the Program is projected to serve over 111,000 retail customers and have annual electricity sales of over 1,300 GWh. Annual revenues are projected to be approximately $128 million. The break down of projected sales by major customer class is shown in the following figure.

[4] Customer account totals represent estimates based on an escalation of 2005 account data provided by PG&E. An annual escalation rate of 0.5% was applied to this PG&E data with an assumption that 100% of Phase 1 customers and 90% of Phase 2 and 3 customers were retained (10% opt-out per class).

Figure 2: Projected Customer Mix In 2011



3. Electric Resources

Beginning with the commencement of service to Phase 1 customers in 2010 through 2013, the Authority would contract with a third party electric supplier under a "full requirements" contract, which places the responsibility for arranging for power to be delivered to program customers with the supplier. The Authority would establish specific renewable standards that the supplier must meet. The proposed renewable standard begins at 56% in 2010 (based on a weighted average of program customers participating in a 100% renewable supply tariff as well as the 25% renewable supply provided to cost-sensitive program customers – these two distinct tariff options are discussed in additional detail below). Beyond 2013, the Program intends to promote additional renewable energy utilization to the level of 80% (based on a weighted average of program customers participating in the 100% renewable supply tariff as well as the 51% renewable supply provided to cost-sensitive program customers, a planned increase from the 25% introductory renewable supply level that occurs in 2014) or greater; achievement of this ambitious goal will likely depend on the Authority's investment in the development of new renewable generation capacity.

To meet this goal, the Authority would develop and potentially finance 200 MW of renewable generating capacity, scheduled to be online in 2014. Resource development and financing would likely be conducted with another public agency or agencies with experience in electric resource development. Additional renewable energy purchases would supplement the Authority's generation to sustain or exceed the 80% renewable energy target. In addition, the

Authority would promote expanded customer side energy efficiency and demand response programs and target deployment of approximately 13 MW of distributed solar within its service area by 2019.

The clean electric supply portfolio developed by the Authority is expected to result in net reductions in greenhouse gas emissions of between 302,330 to 534,369 tons per year by 2019 due to displacement of natural gas generation that would otherwise be used. GHG reductions of this magnitude represent between 10% and 17% of the Marin Communities' current emissions total (from all sectors).

4. Rates

The ability to meet these goals will be confirmed during the program's supplier solicitation process. The Program's preliminary goals are based on the development of two distinct rate tariffs between which program customers may choose: 1) 100% renewable, or "Green," energy supply; and 2) a graduated renewable energy supply option, or "Light Green." The 100% Green Tariff will provide program customers with 100% renewable energy supply at a rate premium of approximately 1.9 cents/kWh. This premium will be directly related to the incremental cost incurred by the program to procure necessary renewable energy supplies as well as administrative costs, including increased reserve requirements, related thereto. The Light Green Tariff is designed with cost-sensitive customers in mind, providing these residents and businesses with a relatively high level of renewable energy supply (25% in 2010, increasing to 51% in 2014) at a generation rate equivalent to the incumbent utility, PG&E. Projected program rates for each of the program's two tariffs are shown in the following table. ***The following rates are illustrative and subject to change pending the pricing information that will be requested from potential suppliers.***[5]

[5] Based on initial supplier responses received by the SJVPA and the East Bay communities as well as the Program's expressed interest in achieving a highly renewable resource mix when operations commence, the Program will likely set rates that are equivalent to those of the incumbent utility, PG&E.

Table 2: Marin CCA Program Estimated 2011 Program Rates

Customer Class	Program Rates – 100% Green (Cents Per kWh)	Program Rates – Light Green (25/51%) (Cents Per kWh)	PG&E Generation Rate (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 at 3.5% per year to 2011.			

The Authority would establish its rates on an annual basis, as it adopts its budget for the coming year. Program customers would be provided with notices of rate changes and be given the opportunity to comment on proposed rate changes before they are made effective by the Authority's Board of Directors at a duly noticed public meeting.

Customers would be provided with four notices and opportunities to opt-out of the program without penalty of any kind, twice within 60 days prior to enrollment and twice within the first two months of service. Following the free opt-out period, customers would be allowed to discontinue service, subject to payment of a nominal Termination Fee. The proposed Termination Fee includes an Administrative Fee (proposed at $5 for residential customers) and, if necessary, a Cost Recovery Charge to prevent shifting of costs to remaining Program customers. The Authority's Board would establish the Cost Recovery Charge as part of its ratesetting responsibilities in the case where the costs of the program's electric supply commitments exceed the prevailing market price for electricity. The Cost Recovery Charge would provide a financial backstop to be used as partial security for financing of the Authority's power supply commitments and as credit support for the electric supply agreement. Additional refinement of the Termination Fee would require input from the Cities' financial advisors, investment bankers, bond counsel and customers for inclusion in the Program's Implementation Plan. The Authority's Board of Directors would also 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.

5. Financial Plan

It is estimated the Authority would need to procure full requirements power supply for the four-year Implementation Period at an average cost of 8.8 cents per kWh (for power supply corresponding with the conventional/renewable mix provided in the Light Green Tariff) to be able to offer rates equal to those of PG&E. A pro forma for the implementation period, including generation rates equivalent to PG&E, is shown in the following table, based on a full requirements contract price of 8.8 cents per kWh. Costs and revenues presented in ***the table below are illustrative and subject to change based on responses to the County's and Cities' request for information and proposals from third party electric suppliers.***

Table 3: Marin Power Authority
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

6. Financings

To achieve program commencement in January 2010, the Authority would need to establish credit in mid 2009 sufficient to obtain short term financing, likely a letter of credit, for approximately $6.4 million to cover program startup costs and working capital associated with Phases 1 and 2. Additional capital requirements for Phase 3 are estimated at $9.4 million. These amounts would be repaid over a five to seven year term.

Financing to support development of the Authority's renewable generation capacity would require an approximately $500 million issuance of revenue bonds. The bonds could be issued by the Authority or by another public agency which would sell the output to the Authority. This financing would occur once specific projects are completely sited and the CCA Program is fully up and running. The anticipated financial close for the renewable resource project would be winter 2010. The financing would be in the range of a 20 to 30 year term.

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

Table 4: Anticipated Authority Financings

PROPOSED FINANCING	ESTIMATED 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 Financing	$500 million	20-30 years	Late 2011

7. Implementation Schedule

There are several major steps that would need to be accomplished prior to the initiation of the CCA Program outlined in this business plan. Five of these steps represent decision points or "off ramps" that allow for program participants to periodically evaluate the prospective CCA program based on current market conditions, evolving community preferences and various other considerations before proceeding with the implementation process.

Five natural decision points or "off ramps" are built into the business plan. The first occurs once the business plan is finalized and the county and cities elect whether to continue with development and filing of a formal Implementation Plan or to terminate their investigation of CCA. The goal is for the county and cities to have sufficient information with respect to the likelihood of the program meeting its renewable energy and rate objectives, assurance that the risks are understood and manageable, and that the plan is financially sound for the county and cities to make an informed decision whether to continue. The second decision point occurs after the JPA Agreement and the Implementation Plan have been drafted and each participating community has been given the opportunity to review and comment on the documents. At that time, the county and cities will determine whether or not to continue with actual program implementation in the form of unique ordinances, consistent with the statutory requirements of AB 117. This second off-ramp provides an opportunity for leadership within each participating community to consider community-specific feedback before deciding to participate in the JPA. Following the passage of ordinances, participating Members will commence operation of the Marin Power Authority and will issue a Request for Bid to prospective energy suppliers.

The third and fourth off-ramps require the Authority's Board to approve both the Implementation Plan and Program Agreement 1. Following approval of the Implementation Plan, this document would be filed with the CPUC for certification. The fifth, and final, decision point occurs after the CPUC certifies the Implementation Plan, and the county and cities elect whether or not to continue with actual program implementation. This decision point allows the JPA to deal with potential regulatory decisions that could materially change the program as well as any developments in current market conditions that may preclude the program from meeting its economic and/or renewable supply objectives.

The planned sequence of events showing major steps prior to the CCA program beginning to serve customers is shown in Table 5.

Table 5: Timeline for Implementation

ACTIVITY	TIMELINE
Complete Business Plan	February 2008
Task Force Recommendation to Proceed	March 2008
Complete JPA Agreement	March 2008
Develop Draft Implementation Plan	March 2008
Public Workshops	March 2008 – April 2008
City and County Ordinances	April 2008 – December 2008
Commencement of the Authority	+30 Days
Issue Supplier Request for Bids and Select Seller	+30 Days
Approve Implementation Plan	+120 Days
Approve Program Agreement 1	+120 Days
File Implementation Plan with CPUC	+120 Days
Final Evaluation upon CPUC Certification of filed Implementation Plan	+180 Days
Final Go/No Go Decision by the Marin Power Authority	+200 Days
File Registration Package with CPUC	+230 Days
Resolve Outstanding Issues	+240 Days
Execute Supplier/Vendor Contracts	+260 Days
Finalize Initial Rates	+270 Days
60 Day Notice	+270 Days
Go live phase 1	+330 Days

CHAPTER 1 – Introduction

Following passage of Assembly Bill 117 in 2002, which created the legal authority for cities and counties to provide electric service through Community Choice Aggregation, the County of Marin, on behalf of the unincorporated areas of the county as well as the eleven cities within its geographic boundaries, which include San Rafael, Novato, Corte Madera, Mill Valley, Larkspur, Sausalito, San Anselmo, Tiburon, Fairfax, Ross and Belvedere, initiated a feasibility study to evaluate the costs and benefits of implementing CCA programs within its jurisdiction. Under California law, CCA allows cities, counties, or joint power agencies (JPA's) comprised of cities and/or counties to implement programs that aggregate the electric loads of customers within their jurisdictional boundaries for purposes of electricity procurement. This allows the city/county/JPA (CCA Provider) to make wholesale purchases of electricity on behalf of its constituents, providing an alternative to the incumbent utility, PG&E.

The feasibility study found that it would be economically feasible for the county and the eleven cities to jointly implement a CCA program and significantly increase the use of renewable energy resources in fulfilling the electricity requirements of the communities. The studies found that the county and cities could jointly provide electricity to program customers at costs lower than the rates projected to be charged by PG&E due in large part to the ability of these local governments to finance generation facilities using low cost, tax-exempt bonds. The feasibility study found that additional cost savings could be achieved if the county and cities joined together to procure electricity for the program and conduct certain common activities. The feasibility studies also identified several risks and uncertainties that would need to be addressed as the program is implemented and operated. Finally, the feasibility study identified the steps that must be completed in the formation of a CCA program, including the development of the legally required Implementation Plan that identifies how the program would be organized, funded and operated.

Marin County retained an independent consultant to perform a peer review of the feasibility study. The peer review concluded that the feasibility study provided sufficient information to proceed with the next phase of the project, which involves development of a program business plan. The peer review also suggested changes in certain underlying analytical assumptions and recommended additional sensitivity analyses that should be included in the next phase of study.

A limited feasibility study update was subsequently performed, incorporating the recommendations of the peer review team. The results of the updated feasibility study generally fell within the range of sensitivities contained in the original feasibility study. The updated analyses did not change the overall conclusions and recommendations contained in the original study.

The Marin Communities then decided to collaboratively develop a business plan for implementing a joint CCA program. During this process, leadership within the Marin Communities expressed an interest in understanding the potential impacts of a CCA program that would offer a 100% renewable energy supply to its customers. Specifically, the Marin Communities wanted to determine the extent to which local climate impacts could be mitigated through the implementation of a highly renewable energy supply portfolio. After evaluating the economic and environmental implications of such a program (program rates would likely exceed utility rates over the near term of 5-10 years; significant, sustained GHG reductions could be achieved), the Marin Communities jointly decided to proceed with the development of a CCA business plan that will offer customers 100% renewable energy supply and will affect GHG reductions up to 17% of current totals within the Marin Communities. This business plan outlines a framework for how a CCA program serving Marin County and the eleven cities located therein could be organized, governed, operated, and financed. Many aspects included within this business plan are universally applicable to any local government(s) that may choose to pursue CCA. However, each CCA program will have unique goals, objectives and demographic profiles as well as many other characteristics impacting program development. The unique characteristics, specific to Marin's CCA Program, have been identified herein and addressed in the program-specific analyses underlying this business plan. Details reflected in this business plan were developed in consideration of the current legal and regulatory frameworks affecting CCA participants. This business plan contains the following sections:

- Organizational Plan
- Load Forecast and Resource Plan
- Financial Plan
- Ratesetting and Program Terms
- Procurement Process
- Program Termination

The business plan will be subject to much discussion and refinement among the county's and cities' representatives, stakeholders, outside experts and the public before a decision to proceed with developing a formal Implementation Plan can be made. Ultimately, the evaluation will incorporate price offers from third party electric suppliers, which will provide the certainty needed to determine whether the program can offer the rates proposed herein, while meeting the program's specified renewable energy targets, upon initiation. Information from potential electric suppliers has not been requested at this time, but the Marin Communities have utilized the information received by the SJVPA and the East Bay Communities in response to their non-binding requests for information.

This document represents a comprehensive draft business plan for the Marin CCA program. It presents to the Marin Communities a compilation of proposed plans for organization and governance, ratesetting policies and processes, staffing plans, roles and responsibilities, detailed startup costs and financing, a phased customer enrollment plan, energy efficiency and distributed generation plans, suggested renewable resource technologies and generally defined locations for development, program terms and conditions, and a process for procuring the key third party services needed for program implementation. Final revisions to this draft business plan will be based on input received from the Marin Communities as well as other interested stakeholders and advisors. Several preliminary concepts are presented in this plan that will require input from the county's and cities' financial advisors, bankers and attorneys. The ability to offer competitive rates will be addressed in greater detail once the Marin Communities have formed a joint powers agency and have issued a request for bid to potential suppliers (January 2009). At that time, the JPA's Governing Board will evaluate the responses received from potential suppliers and will initiate a full analysis of financial sensitivities to ensure that the program can meet its specified objectives. For the time being, many of the quantitative analyses supporting this business plan utilize energy prices that were offered by private energy suppliers to the East Bay Communities and the SJVPA.

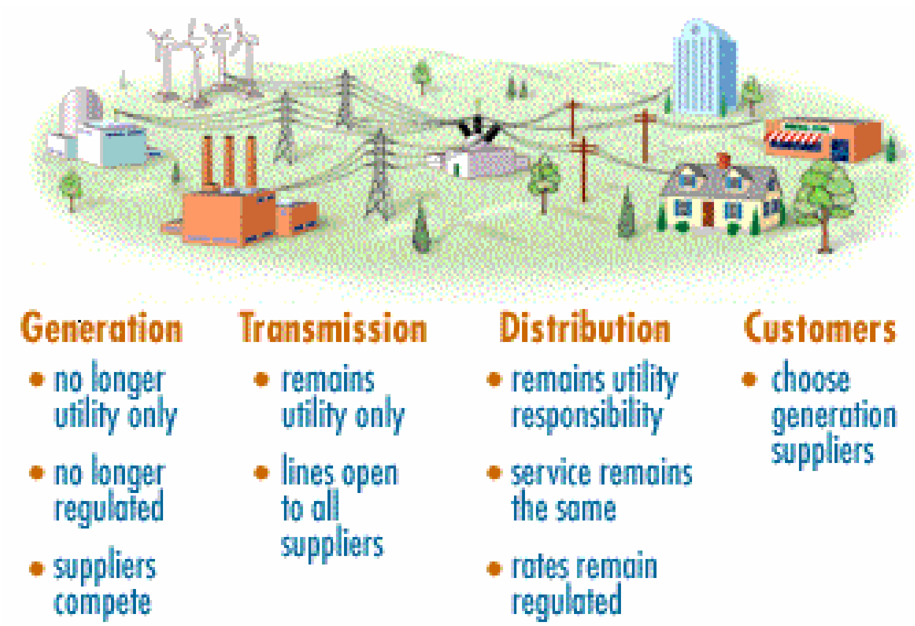
Five natural decision points or "off ramps" are built into the business plan. The first occurs once the business plan is finalized and the county and cities elect whether to continue with development and filing of a formal Implementation Plan or to terminate their investigation of CCA. The goal is for the county and cities to have sufficient information with respect to the likelihood of the program meeting its renewable energy and rate objectives, assurance that the risks are understood and manageable, and that the plan is financially sound for the county and cities to make an informed decision whether to continue. The second decision point occurs after the JPA Agreement and the Implementation Plan have been drafted and each participating community has been given the opportunity to review and comment on the documents. At that time, the county and cities will determine whether or not to continue with actual program implementation in the form of unique ordinances, consistent with the statutory requirements of AB 117. This second off-ramp provides an opportunity for leadership within each participating community to consider community-specific feedback before deciding to participate in the JPA. Following the passage of ordinances, participating Members will commence operation of the Marin Power Authority and will issue a Request for Bid to prospective energy suppliers.

The third and fourth off-ramps require the Authority's Board to approve both the Implementation Plan and Program Agreement 1. Following approval of the Implementation Plan, this document would be filed with the CPUC for certification. The fifth, and final, decision point occurs after the CPUC certifies the Implementation Plan, and the county and cities elect whether or not to continue with actual program implementation. This decision point allows the JPA to deal with potential regulatory decisions that could materially change the program as well as any developments in current market conditions that may preclude the program from meeting its economic and/or renewable supply objectives.

Following these predetermined off-ramps, CCA customers are given four additional opportunities to opt-out of program service by responding to service notices included in their utility bills. Each of these off-ramps, coupled with the customer notification requirement and related opt-out provisions, will ensure that this CCA program is undertaken by well-informed decision-makers and subscribed to by willing customers.

Background on CCA
AB 117 provides for the CCA Program to be an opt-out program, meaning that all customers are included in the program unless they make a positive declaration that they do not wish to participate.

The CCA Provider will only procure the electric energy commodity; the actual delivery of the commodity remains the obligation of PG&E. PG&E will continue to provide all non-generation-related services, including delivery, metering, billing, customer service, and traditional retail customer services. This is an important distinction of CCA compared to a municipal utility that owns the transmission and distribution wires and distributes electricity. The following figure illustrates the potential electricity delivery under a CCA Program.



In the current electric marketplace, PG&E no longer owns a substantial amount of generation, with the exception of its hydroelectric and nuclear assets. However, PG&E has announced plans to invest billions in new generation over the next several years and is poised to re-enter the generation market that it exited during the restructuring period of the late 1990s. PG&E purchases the rest of its electric needs from the wholesale marketplace and is the monopoly provider of transmission and distribution services. Under CCA, the customer (i.e. the CCA Provider) chooses the types and amount of generation that it purchases (or owns) for its constituents. Customers are able to choose the generation services offered by the CCA or the generation services offered by the incumbent utility. The wires (transmission and distribution) continue to be provided by the local monopoly.

PG&E supported AB 117, but its responses to prospective CCA programs throughout the state have been consistently negative. When given the opportunity to comment on specific CCA documents (such as business plans or implementation plans) and/or various programmatic objectives, PG&E has been reluctant to identify any specific aspects of these programs which it supports without qualification or reservation. Furthermore, PG&E has offered limited constructive feedback to prospective CCA programs since the passage of AB 117, choosing to focus its efforts on downplaying and/or challenging the environmental and potential economic benefits of such programs. Nevertheless, PG&E has provided all of the information that the county and cities have requested to date and remains cooperative in the Marin Communities' efforts to gather information necessary to evaluate CCA, which is consistent with the minimum requirements imposed by AB 117. Based on PG&E's active opposition to the SJPVA CCA program and public criticism of the proposed CCA program for the City and County of San Francisco, Marin should expect PG&E to oppose its efforts going forward, including targeted lobbying of large energy customers and political officials.

CCA Program Components (Implementation Plan Requirements)

This section contains a broad overview of the major components of the CCA Program organized under the requirements of AB 117, which state that all CCA Programs must, at a minimum, address the following:

- Organizational structure of the program, its operations, and funding;
- Rate setting and other costs to participants;
- Disclosure and due process in setting rates and allocating costs among participants;
- Methods for entering and terminating agreements with other entities;
- The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures;
- Termination of the Program; and
- A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

Additionally, AB 117 added Section 366.2 (c)(3) to the California Public Utilities Code requiring that an Implementation Plan provide for:

- Universal access;
- Reliability;
- Equitable treatment of all classes of customers; and
- Any requirements established by state law or by the CPUC concerning aggregation services.

There are several other cities or potential groups of cities and/or counties around California that are also considering implementing a CCA program. To date there is only one CCA program operating in California, the San Joaquin Valley Power Authority, scheduled to begin serving customers in 2008.[6] The first CCA Implementation Plan in California was submitted to the California Public Utilities Commission by a new joint powers agency, the SJVPA, which

[6] Community aggregation programs also exist in other states including Massachusetts, Texas, and Ohio. The Ohio program is very similar to the CCA programs proposed for California.

represents municipalities in the greater Fresno area, on January 29, 2007. Subsequent to this submittal, the SJVPA filed revisions with the CPUC on April 27, 2007 and again on August 27, 2007. On September 7, 2007, the California Public Utilities Commission provided notice to the SJVPA certifying that its current Implementation Plan contained sufficient data, as required by California Public Utilities Code Section 366.2. Much has been and will continue to be learned from the experiences of the SJVPA as it proceeds with its formation and commencement of operations during 2007. Other notable CCA efforts include the City and County of San Francisco, the East Bay Communities, the City of Chula Vista, and the Cities of Beverly Hills and West Hollywood.

Program Implementation
There are several major steps that would need to be accomplished prior to the initiation of the CCA program outlined in this business plan. Following completion of the final business plan, creation of the necessary program agreements, and a decision to proceed with developing an Implementation Plan, the first major step would be for the county and cities to approve a joint powers agreement and to form the JPA. The county and each city would also need to pass unique ordinances, as required by AB 117, declaring the county's and each city's intent to file a CCA Implementation Plan through the Authority. Formation of the JPA will be a significant milestone. Once formed, the JPA can solicit offers for power supply and other services, adopt an Implementation Plan, and file the Implementation Plan with the CPUC. These activities would take place before a final program evaluation is made, making formation of the Authority a critical step in the CCA evaluation process.

The planned sequence of events showing major steps prior to the CCA program beginning to serve customers is shown in Table 6. Approval of voters is not legally required for formation of a CCA program, but the county and cities have allowed time in their implementation schedule for individual communities to hold an election on this issue, if this becomes necessary.[7] As proposed, the JPA would require at least three participants, including the County of Marin, the City of San Rafael and the City of Novato, to execute the JPA agreement to become effective.

[7] The County of Marin has mentioned that the decision to proceed with CCA may require a ballot measure for the county and certain participating cities in the event that a rate increase, relative to generation rates charged by PG&E, is projected. Potential generation rates of the Program will become more certain after the Program receives responses to its request for bids from energy suppliers in January 2009.

Table 6: Timeline for Implementation

ACTIVITY	TIMELINE
Complete Business Plan	February 2008
Task Force Recommendation to Proceed	March 2008
Complete JPA Agreement	March 2008
Develop Draft Implementation Plan	March 2008
Public Workshops	March 2008 – April 2008
City and County Ordinances	April 2008 – December 2008
Commencement of the Authority	+30 Days
Issue Supplier Request for Bids and Select Seller	+30 Days
Approve Implementation Plan	+120 Days
Approve Program Agreement 1	+120 Days
File Implementation Plan with CPUC	+120 Days
Final Evaluation upon CPUC Certification of filed Implementation Plan	+180 Days
Final Go/No Go Decision by the Marin Power Authority	+200 Days
File Registration Package with CPUC	+230 Days
Resolve Outstanding Issues	+240 Days
Execute Supplier/Vendor Contracts	+260 Days
Finalize Initial Rates	+270 Days
60 Day Notice	+270 Days
Go live phase 1	+330 Days

CHAPTER 2 – Organizational Plan

This section outlines a proposed organizational plan for Marin's CCA program, including proposed governance principles for a new joint powers agency that would administer the program. This section defines the necessary agreements and describes how the program would be governed, managed, and staffed.

Organizational Overview

Pursuant to AB 117, a CCA may be a city, a county, a city and county, or a combination of cities and counties that have elected to jointly implement a CCA program through formation of a joint powers agency ("JPA"). The geographic boundaries of participating cities and/or counties need not be contiguous. The proposed governance structure for the program is formation of a new JPA whose Board of Directors would have primary responsibility for managing all aspects of a common CCA program for the County of Marin, California (County) as well as the eleven cities within the geographic boundaries of the County. According to the implementation timeline presented above in Table 6, a deadline of December 31, 2008 has been imposed for the County of Marin as well as each of the eleven cities to vote on joining the JPA (and pass a related ordinance in accordance with state law). For purposes of this business plan, the new JPA will be referred to as the Marin Power Authority or simply the "Authority".

As proposed, the Program would be governed by the Authority's Board of Directors (Board), appointed by the Members. The Authority would be a joint exercise of powers agency formed under California law. The County of Marin and each city that has elected to offer the Program to its constituents would become a Member of the Authority. The Authority would be the CCA entity that would register with the CPUC, and it would be responsible for implementing and managing the program pursuant to the Joint Powers Agreement. The Program would be operated under the direction of an Executive Director appointed by the Board of Directors. The Executive Director would report to the Authority's Board of Directors comprised of one representative from each participating Member of the Authority. Those who will be eligible to serve as representatives on the Board will be elected officials from the then-current County Board of Supervisors (one Board representative will be selected from the County Board of Supervisors) and the City Councils (one representative will be selected from each of the eleven City Councils) of the eleven member cities. Representatives serving on the Board may be provided with a periodic stipend ($100 per representative per month, for example) as part of their participation in this governing body. The Board may adjust or discontinue the payment of such stipends at its discretion.

The Board of Director's primary duties would be to establish program policies, set rates and provide policy direction to the Executive Director, who will have general responsibility for program operations, consistent with the policies established by the Board. The Board will also determine necessary staffing levels, individual titles and related compensation within the

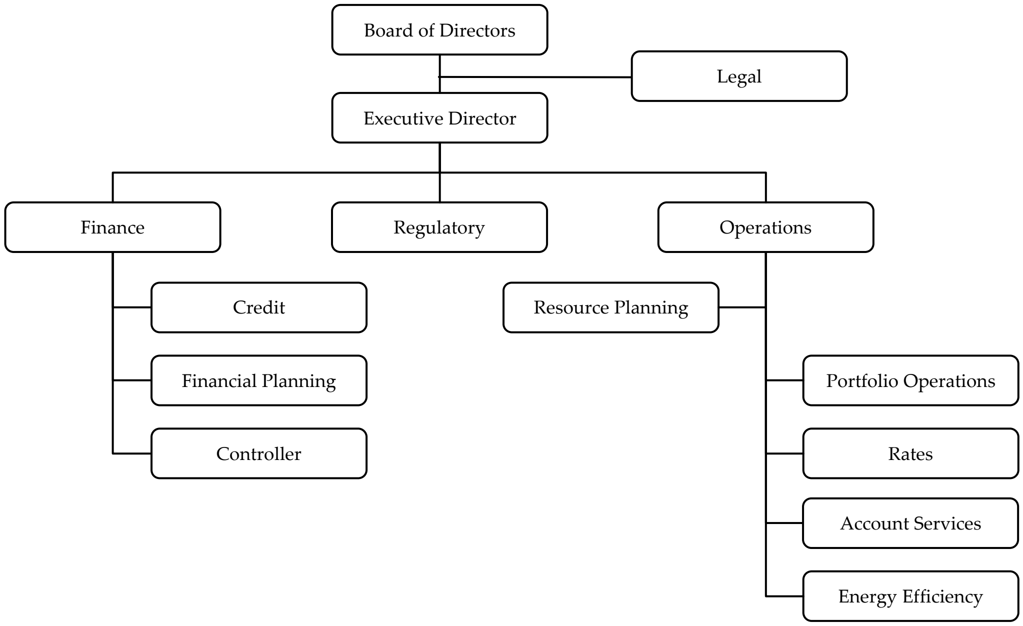
Authority. The Board may also adjust staffing levels and compensation over time in response to varying workloads, specific programs and/or general responsibilities of the Authority.

The Executive Director could be an employee of the Authority, an individual under contract with the Authority, a corporation, or any other person so designated by the Board. The Board would be responsible for evaluating the Executive Director's performance and is ultimately responsible for hiring and terminating the Executive Director.

The Board would also establish a Chairman and other officers from among its membership and may establish an Executive Committee and other committees and sub-committees as needed to address issues that require greater expertise in particular areas (e.g., finance or contracts). The Authority will establish an "Energy Commission" formed of Board-selected designees. The Energy Commission will have responsibility for evaluating various issues that may affect the Authority and its customers, including rate setting, and will provide analytical support and recommendations to the Board in these regards. The following chapter contains proposed elements of a JPA agreement. Once the principles are agreed to by representatives of the county and cities, a JPA agreement that defines the terms and conditions by which the Authority will be governed would be developed by qualified legal counsel.

The Executive Director would have responsibilities over the functional areas of Finance, Regulatory Affairs, and Operations. It is recommended that operations would be conducted utilizing a combination of internal staff and contractors. Certain specialized functions needed for program operations, namely the electric supply and customer account management functions described below, should be performed initially by experienced third-party contractors. The Program organizational chart showing relationships among the Board of Directors, the Executive Director and the functional areas is shown in Figure 3.

Figure 3: Program Organization



Governance

The Authority would have a Board of Directors consisting of one representative from each of the Members. As previously noted, those who will be eligible to serve as representatives on the Board will be elected officials from the then-current County Board of Supervisors and the City Councils of the eleven member cities. The Board would meet at regular intervals to provide the overall management and guidance for the Authority. All Board meetings would be public and held in accordance with the Ralph M. Brown Act.

Decisions by the Authority would take place under voting procedures defined in the JPA Agreement. All votes on a particular matter are subject to a two-tier approval process: first, any decision must be approved by a simple majority of the Directors at the Governing Board meeting; second, assuming the first requirement is reached, those Directors voting in the affirmative must constitute over 50 percent of a weighted voting percentage comprised of equal treatment of each Member's electricity requirements (expressed as a ratio of each Member's electricity requirements divided by total energy requirements of the Program) and a pro rata percentage of total membership. That is, one-half of the combined vote is based upon the total number of Members (i.e., 12 Members each receive 4.17 percent [50%/12]) and one-half of the combined vote is based upon annual electric usage. Table 7A is illustrative of the proposed voting percentages for the **second tier** vote.

Table 7A
Voting Percentages for the Second Tier Vote

Member	Estimated Percent of Total Program Load	Load Voting Percentage (50%)	Pro Rata Percentage (50%)	Total Voting Percentage (Tier 2)
Belvedere	0.79%	0.40%	4.17%	**4.57%**
Corte Madera	5.70%	2.85%	4.17%	**7.02%**
Fairfax	1.78%	0.89%	4.17%	**5.06%**
Larkspur	4.79%	2.40%	4.17%	**6.57%**
Marin County	25.05%	12.52%	4.17%	**16.69%**
Mill Valley	4.88%	2.44%	4.17%	**6.61%**
Novato	20.20%	10.10%	4.17%	**14.27%**
Ross	1.00%	0.50%	4.17%	**4.67%**
San Anselmo	3.60%	1.80%	4.17%	**5.97%**
San Rafael	25.04%	12.52%	4.17%	**16.69%**
Sausalito	3.94%	1.97%	4.17%	**6.14%**
Tiburon	3.22%	1.61%	4.17%	**5.78%**
	100%	50.0%	50.0%	**100.00%**

An alternative second tier voting structure would emphasize number of customer accounts as opposed to electricity requirements. In this case, the first tier vote, which must achieve simple majority approval, does not change. However, in the alternative second tier voting structure, those Directors voting in the affirmative must constitute over 50 percent of a weighted voting percentage comprised of equal treatment of each Member's customer account total (expressed as a ratio of each Member's customer account total divided by the total number of customer accounts within the Program) and a pro rata percentage of total membership. That is, one-half of the combined vote is based upon the total number of Members (i.e., 12 Members each receive 4.17 percent [50%/12]) and one-half of the combined vote is based upon number of customer accounts. Table 7B illustrates the proposed alternative voting percentages for the **second tier** vote.

Table 7B
Alternative Voting Percentages for the Second Tier Vote

Member	Estimated Percent of Total Program Accounts	Account-Based Voting Percentage (50%)	Pro Rata Percentage (50%)	Total Voting Percentage (Tier 2)
Belvedere	0.95%	0.47%	4.17%	4.64%
Corte Madera	3.87%	1.94%	4.17%	6.11%
Fairfax	3.07%	1.53%	4.17%	5.70%
Larkspur	5.48%	2.74%	4.17%	6.91%
Marin County	24.96%	12.48%	4.17%	16.65%
Mill Valley	5.60%	2.80%	4.17%	6.97%
Novato	19.20%	9.60%	4.17%	13.77%
Ross	0.80%	0.40%	4.17%	4.57%
San Anselmo	4.94%	2.47%	4.17%	6.64%
San Rafael	22.93%	11.46%	4.17%	15.63%
Sausalito	4.35%	2.17%	4.17%	6.34%
Tiburon	3.86%	1.93%	4.17%	6.10%
	100%	50.0%	50.0%	**100.00%**

Officers

The Authority would have a Chair and Vice-Chair elected to one-year terms by the Board of Directors. Both the Chair and Vice-Chair must be members of the Board. In addition, the Authority would have a Board Clerk and Auditor; neither of which will be members of the Board of Directors. The JPA Agreement will provide further details on each of these positions.

Committees

The Authority may elect to have additional committees or working groups to address various topics. Potential committees include: Resource Committee, Finance/Budget/Audit Committee, Legal/Regulatory Committee, and Risk Management Committee. In addition to these potential committees, the Authority would form an appointed Energy Commission, which will be comprised of Board designees from the Member communities. Appointments will be made based on various skill sets and expertise that will be useful in evaluating matters affecting the Authority and its customers, specifically issues related to rate setting and other technical matters. The Energy Commission will provide the Board with recommendations and related analysis to support policy-level decisions of the Board. Any additional committees and their functions would be determined by the Board of Directors at the time each committee is created.

Addition/Termination of Participation

The proposed principles for a JPA Agreement provide for the addition of new participants subject to the affirmative vote of the Authority's Board of Directors pursuant to the voting structure described above. The Board would determine the specific terms and conditions under which a new Member could be admitted; for example, a new Member might be subject to a buy-down fee for costs incurred by the original Members in establishing the Program.

A JPA Member would be able to withdraw itself from the JPA subject to the specific terms and conditions ultimately contained in the JPA Agreement. As proposed, withdrawal of individual Members may occur 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 the Authority 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 the Authority, however, the non-municipal accounts (such as residential, commercial and industrial accounts) would remain customers of the Authority and would continue to receive electricity procured by the Authority on their behalf. Because these non-municipal accounts would remain customers of the Authority, 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 Authority 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 the Authority; 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.

Termination of the Authority

The proposed principles for a JPA Agreement include provisions addressing termination of the Authority. As proposed, termination of the Authority would only occur after a majority of the Member's governing bodies (County Board of Supervisors and/or City Councils) adopt a termination ordinance or resolution and provide adequate notice to the Authority (such as 90 days). Following such notice, the Authority 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.). Termination of the Authority is also addressed in Chapter 8, Program Termination.

Agreements Overview

There are two principal agreements that would govern the Authority and its CCA Program: the JPA Agreement and Program Agreement No. 1 (PA-1). Each of these agreements and its functions are discussed below.

Joint Powers Agreement

The JPA Agreement would create the Authority and delineate a broad set of powers related to the study, promotion, development, and conduct of electricity-related projects and programs. It is anticipated that the Authority would have broad authorities and powers, but a very limited role without implementing agreements ("program agreements") to carryout specific programs. This structure is intended to provide flexibility for the Authority to undertake other programs in the future that may be unrelated to CCA on behalf of all or a subset of the Authority's Members. However, the Board will have limited decision making authority regarding land use within the Member communities. Any issues involving land use within Member communities will be raised with the potentially effected Member. In these instances, the land use and building regulations of each Member shall apply to any JPA facilities located within the jurisdiction of that Member.

Any amendments to the JPA Agreement will be subject to prior approval by each of the Member's governing bodies (County Board of Supervisors and/or City Councils). Following such approval, the Authority would vote on prospective amendments subject to a two-tiered vote, as previously described.

The first program agreement or PA-1, discussed in greater detail below, would provide for the development, implementation and operation of a CCA Program. At the Authority's Members' discretion, future program agreements could provide for other energy related programs. The JPA Agreement specifies the governance provisions of the Authority, which is discussed in greater detail below.

Program Agreement No. 1

PA-1 would outline the framework for the CCA Program, and transfer the participating Members' authority under AB 117 to the Authority. Approval of PA-1 by a participant would authorize the initiation of the CCA Program for its jurisdiction, subject to a commencement notice to be made by the JPA Board. It is anticipated that the county and cities would consider approval of PA-1 after proposals have been received in response to the Authority's supplier selection process and the economics of the Program have been confirmed.

Agency Operations

The Authority would conduct program operations through its own internal staff and through contracting for services with third parties. The Authority would have its own General Counsel to manage its legal affairs. The Authority's Executive Director will have responsibility for day-to-day operations of the Program. To assist the Executive Director, the Authority will hire a full-time Administrative Assistant, who will also serve as Board Clerk, as well as a full-time Policy Analyst to provide analytical support and regulatory review.

Major Authority functions that will be performed and managed by the Executive Director are summarized below.

Resource Planning

The Authority would be charged with developing both short (one and two-year) and long-term resource plans for the program. The Executive Director would manage staff and contractors to develop the resource plan under the guidance provided by the Board and in compliance with California Law, and other requirements of California regulatory bodies (CPUC and CEC).

Long-term resource planning includes load forecasting and supply planning on a ten- to twenty-year time horizon. The Authority's CCA planners will develop integrated resource plans that meet program supply objectives and balance cost, risk and environmental considerations. Integrated resource planning considers demand side energy efficiency and demand response programs as well as traditional supply options. The CCA Program will require an independent planning function even if the day-to-day supply operations are contracted to a third party energy supplier. A preliminary long-term resource plan is contained in Chapter 3. It is anticipated that such plans would be updated and adopted by the Board on an annual basis.

Portfolio Operations

Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These highly specialized activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of program customers.

- *Risk Management* – standard industry techniques will be employed to reduce exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices.

- *Load Forecasting* – develop accurate load forecasts, both long term for resource planning and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.

- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO.

The Authority will initially contract with an experienced and financially sound third party to perform most of the portfolio operation requirements for the CCA Program. This will include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading. A description of the planned selection process for the third parties that will be supplying electricity under the program is contained in Chapter 6.

As the Authority gains experience and begins internalizing more of the functions initially provided by third parties, it will be important for the Authority to approve and adopt a set of

<u>Program Controls</u> that would serve as the risk management tools for the Executive Director and any third party involved in the program's portfolio operations. Program Controls will define risk management policies and procedures and a process for ensuring compliance throughout the organization. During the initial startup period, the chosen full requirements electric supplier will bear the majority of program risks, pursuant to the terms and conditions of the electric supply agreement.

Energy Efficiency
A key focus of the CCA Program will be the development and implementation of an energy efficiency program for the Authority's Members. The Executive Director will be responsible for further development of this Program. To assist the Executive Director in this regard, the Authority will hire a full-time Energy Efficiency Program Manager and three full-time Energy Efficiency Project Managers to administer the energy efficiency program, develop energy efficiency marketing strategies, perform customer outreach and conduct related analyses to support chosen courses of action. As experience is gained from the retail energy side of the CCA Program, the Authority will continue enhancing its Energy Efficiency program to achieve desired goals and objectives of the program. Energy efficiency program potential is discussed in Chapter 3.

The Authority would administer energy efficiency, demand response programs, and distributed (solar) generation that can be used as cost-effective alternatives to procurement of supply-side resources. The Authority would attempt to consolidate existing demand side programs into this organization and leverage the structure to expand energy efficiency offerings to customers throughout its service territory, potentially through the CPUC application process for third party administration of energy efficiency programs and use of funds collected through the existing public goods surcharges paid by the Authority's customers.

Rate Setting
The Board of Directors would have the ultimate responsibility for setting the electric generation rates for the Program's customers. The Executive Director in cooperation with the Authority's Energy Commission would be responsible for developing proposed rates and options for the Board to consider before the finalization of the actual rates, subject to the notice requirements and process described in Chapter 5 ("Ratesetting and Program Terms and Conditions"). The final approved rates must, at a minimum, meet the annual revenue requirement developed by the Executive Director, including any reserves or coverage requirements set forth in bond covenants. The Board will have the flexibility to consider rate adjustments within certain ranges, provided that the overall revenue requirement is achieved; this provides an opportunity for economic development rates or other rate incentives.

Financial Management/Accounting
The Executive Director will be responsible for managing the financial affairs of the Authority, including the development of an annual budget and revenue requirement; managing and maintaining cash flow requirements; potential bridge loans and other financial tools; and a large

volume of billing settlements. The Executive Director will use contractors and/or staff in support of these activities, as appropriate.

The Finance function arranges financing for capital projects, prepares financial reports, and ensures sufficient cash flow for the program. This function also plays an important role in risk management by monitoring the credit of suppliers so that credit risk is properly understood and mitigated by the Program. In the event that changes in a supplier's financial condition and/or credit rating are identified, the Program will be able to take appropriate action, as would be provided for in the electric supply agreement. The Finance function establishes credit policies that the program must follow.

It is planned that the retail settlements (customer billing) would be contracted out to an organization with the necessary infrastructure and capability to handle approximately 111,000 accounts during Phase 3 implementation in January 2011. This function is described under Customer Services, below.

Customer Services

In addition to general program communications and marketing, a significant focus on customer service, particularly representation for key accounts, will be necessary. This will include both a call center designed to field customer inquiries and routine interaction with customer accounts. The Executive Director will be responsible for the Customer Services function.

The Customer Account Services function performs retail settlements-related duties and manages customer account data. It processes customer service requests and administers customer enrollments and departures from the program, maintaining a current database of customers enrolled in the program. This function coordinates the issuance of monthly bills through the distribution utility's billing process and tracks customer payments. Activities include the electronic exchange of usage, billing, and payments data with the distribution utility and the Authority, tracking of customer payments and accounts receivable, issuance of late payment and/or service termination notices, and administration of customer deposits in accordance with Authority credit policies.

The Customer Account Services function also manages billing related communications with customers, customer call centers, and routine customer notices. The Authority would initially contract with a third party, which has demonstrated the necessary experience and administers appropriate computer systems (customer information system), to perform the customer account and billing services functions.

The Authority would conduct the general program marketing and key customer account management functions. These responsibilities include the assignment of account representatives to key accounts, which will ensure high levels of customer service to these businesses, and implementation of a marketing strategy to promote customer satisfaction with the CCA program. Ongoing communications, marketing messages, and information regarding the CCA Program to all customers will be critical for the overall success of the CCA Program.

Legal and Regulatory Representation

The CCA Program will require ongoing regulatory representation to file resource plans, resource adequacy, compliance with California RPS, and overall representation on issues that will impact the Authority and its Members. The Authority will maintain an active role at the CPUC, CEC, and, as necessary, FERC and the California legislature. Day-to-day analysis and reporting of pertinent legal and regulatory issues will be completed by the Executive Director's Policy Analyst.

The Authority would retain legal services, as necessary, to administer the Authority, review contracts, and provide overall legal support to the activities of the Authority.

Roles and Functions

The Authority Board would perform the functions inherent in its policy-making, management and planning roles. The Authority would also be the public face of the program and have a direct role in marketing, communications and customer service. As previously noted, other highly specialized functions, such as energy supply and account management, would be contracted out to third parties with sufficient experience, technical and financial capabilities. The functions that would initially be performed by the Authority's Board of Directors, the Executive Director and third parties are specified below:

Organization	***Roles/Functions/Activities***
Authority Board of Directors	*Executive/Policy/Legal*
Executive Director	*Finance*
	Legal and Regulatory - *Legal support* - *Participation in regulatory proceedings* - *Regulatory reporting*
	Marketing/Communications
	Rates & Support - *Rate policy* - *Rate design* - *Cost-of-service planning*
	Resource Planning - *Load research* - *Load forecasting* - *Supply-side/Demand side portfolio planning*
	Contract Management – RFP/RFQ
	Customer Service - *Account representatives* - *Energy efficiency program management*
Energy Supplier	*Supply Operations* - *Procurement* - *Scheduling coordination* - *Settlements (ISO/Wholesale)* - *Short-term load forecasting*
Customer Account Services Provider/Data Manager	*Account Management (Customer Information System)* - *Customer switching* - *New customer processing* - *Data exchange (EDI)* - *Payment processing (AR/AP)* - *Billing and retail settlements* - *Call center*

The Authority would enter into two key contracts with third parties to provide the day-to-day operational functions necessary to procure electricity and manage customer account data. The first of these contracts is with the Program's energy supplier to perform the Supply Operations. The second key contract is with a data management provider to perform the Account Management functions. The Authority would select the contractors for these key roles through a competitive solicitation. Information on the recommended solicitation process to select qualified potential service providers is contained in Chapter 6.

Staffing

Staffing requirements for the above Authority functions are approximately twenty and one-half full time equivalent positions, once the customer phase-in is complete and the program is fully operational. These staffing requirements are in addition to the services provided by the third party energy suppliers and the data manager. The Executive Director would have discretion whether to internally staff these required functions or to contract for these services.

Table 8 illustrates the expectations for start-up, near-term (two to five years), and long-term anticipated staffing roles.

Table 8: Expectations for Staffing Roles

Function	Start-Up	Near-Term (2 to 5 Years)	Long-Term
Program Governance	Authority Board	Authority Board	Authority Board
Program Management	Authority ED	Authority ED	Authority ED
Outreach	Authority ED	Authority ED	Authority ED
Customer Service	Authority ED	Authority ED	Authority ED
Key Account Management	Authority ED	Authority ED	Authority ED
Regulatory	Third Party (Authority ED and Regulatory Analyst support)	Authority ED (Regulatory Analyst support)	Authority ED (Regulatory Analyst support)
Legal	Authority ED	Authority ED	Authority ED
Finance	Authority ED	Authority ED	Authority ED
Rates: Approve Develop	Authority Board Authority ED (third Party support)	Authority Board Authority ED (third Party support)	Authority Board Authority ED
Resource Planning	Third Party (Authority ED support)	Authority ED (third party support)	Authority ED
Energy Efficiency	Third Party	Third Party (Authority ED and Program Energy Efficiency Staff support)	Authority ED (Program Energy Efficiency Staff)
Resource Development	Authority ED (third party support)	Authority ED (third party support)	Authority ED
Portfolio Operations	Third Party	Third Party (Authority ED support)	Authority ED
Scheduling Coordinator	Third Party	Third Party	Third Party (potentially Authority ED)
Data Management	Third Party	Third Party	Third Party (potentially Authority ED)

Staff would be added incrementally to match workloads involved in forming the new organization, managing contracts, and initiating customer outreach/marketing during the pre-operations period. During the pre-startup period, minimal staffing requirements would include an Executive Director, an Assistant to the Executive Director, a Policy Analyst and a Sales and Marketing Manager (4 full time equivalent positions). The Authority anticipates hiring the Executive Director, Assistant to the Executive Director, Policy Analyst and Marketing Manager as its direct staff but may choose to fill all other necessary positions with staff and/or contractors at the discretion of the Executive Director and the Authority's Board. Following these initial staffing efforts, additional staff and/or contractors would be added during the Phase 1 customer enrollment period and following commencement of service to Phase 1 customers. The organization should be nearly fully staffed by the time the Phase 2 customers are enrolled. Phase 2 contains the key commercial and industrial customer segments, the largest of which would have assigned customer account representatives.

Table 9 provides an estimate of the appropriate staff additions (internal staff or equivalent contracted functions) that the Authority would require for 2009–2010 to implement and operate the CCA Program. Actual staff will be dependent upon several factors, including the ability to recruit and hire qualified staff and personnel policies ultimately established by the Executive Director and the Board of Directors.

Table 9: Internal Staffing Estimates

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	Jun-10
Management													
Executive Director	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Policy Analyst	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Administrative Assistant	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Finance and Rates													
Manager	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Rates Analyst	-	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0
Accounting/Billing Analyst	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Sales And Marketing													
Manager	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Account Representatives	-	-	-	-	-	-	-	-	-	3.0	4.0	4.0	4.0
Communications Specialist	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0
Administrative Assistant	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0
Energy Efficiency													
Manager	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0
Project Manager	-	-	-	-	-	-	-	-	3.0	3.0	3.0	3.0	3.0
Regulatory													
Manager	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Regulatory Analyst	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Information Technology													
IT Specialist	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Human Resources													
HR Specialist	-	-	-	-	-	-	-	-	0.5	0.5	0.5	0.5	0.5
Subtotal Staffing	4.0	4.0	4.0	4.0	4.0	5.0	9.0	9.0	14.5	18.5	20.5	20.5	20.5

Table 10 shows the staffing plan for the Authority at initial full-scale operational levels (Phase 3). Customer service for the mass market residential and small commercial customers will be provided by the Program's third party customer account services provider.

Table 10: Staffing Plan for the Marin Power Authority Community Choice Aggregation Program

Position	Staff (Full Time Equivalents)
Management	
Executive Director	1.0
Policy Analyst	1.0
Administrative Assistant	1.0
Finance and Rates	
Manager	1.0
Rates Analyst	1.0
Accounting/Billing Analyst	1.0
Sales and Marketing	
Manager	1.0
Account Representative	4.0
Communications Specialist	1.0
Administrative Assistant	1.0
Energy Efficiency	
Manager	1.0
Project Manager	3.0
Regulatory	
Manager	1.0
Regulatory Analyst	1.0
Information Technology	
IT Specialist	1.0
Human Resources	
HR Specialist	0.5
Total Staffing	20.5

CHAPTER 3 - LOAD FORECAST AND RESOURCE PLAN

Introduction

This Chapter describes the Marin Power Authority's proposed ten-year integrated resource plan, which would create a highly renewable, diversified portfolio of electricity supplies capable of meeting the electric demands of the Authority's retail customers, plus sufficient reliability reserves. This integrated resource plan reflects a long-term, programmatic goal of 100% renewable energy supply. Within five years of program commencement (2014), this significant commitment to renewable resources is projected to result in the Authority meeting over 80% of its total electric needs through renewable resources. As the program moves forward, incremental renewable supply additions will be made based on resource availability as well as economic goals of the program. The Authority's aggressive commitment to renewable generation adoption will involve both direct investment in new renewable generating resources through partnerships with experienced public power developers/operators, significant purchases of renewable energy from third party suppliers and, potentially, the purchase of Renewable Energy Certificates (RECs) from the market. The resource plan also sets forth ambitious targets for improving customer side energy efficiency as well as for deployment of approximately 13 MW of new distributed solar capacity within the jurisdictional boundaries of the Authority by 2019 (year ten of Program operations).

The plan described in this section would accomplish the following by 2019:

- Procure energy needed to offer two generation rate tariffs: 100% Green and 25% Light Green through a full-requirements contract with an experienced, financially stable energy supplier. Through this contract, the remaining energy requirements for the Light Green Tariff will be supplied from efficient, low emission conventional generating resources.
- Increase the renewable content of the Light Green Tariff to over 50% and the average renewable energy supplies of the program to over 80% by 2014, based on projected levels of participation in the Authority's two available generation tariffs.
- Continue increasing renewable energy supplies beyond 2014 based on resource availability and economic goals of the program.
- Develop partnership(s) with experienced public power developer(s) to facilitate development of Program-owned/controlled renewable generating capacity.
- Invest in 200 MW of new renewable generating capacity to be online by 2014.
- Achieve incremental reductions in greenhouse gas emissions ranging from 302,330 to 534,369 tons per year, as much as 17% of the Marin Communities' total GHG emissions.

The Authority would be responsible to comply with regulatory rules applicable to California load serving entities. The Authority would arrange for the scheduling of sufficient electric supplies to meet the hour-by-hour demands of its customers. The Authority would also need to adhere to capacity reserve requirements established by the CPUC and the CAISO designed to address uncertainty in load forecasts and potential supply disruptions caused by generator outages and/or transmission contingencies. These rules also ensure that physical generation capacity is in place to serve the Program's customers, even if there were to be a need for the Program to cease operations and return customers to PG&E. In addition, the Authority would be responsible for ensuring that its resource mix contains sufficient production from renewable energy resources needed to comply with the statewide renewable portfolio standards (20% renewable energy supply by 2010). The resource plan would meet or exceed all of the applicable regulatory requirements related to resource adequacy and the renewable portfolio standard.

Program Phase-In

The Authority would phase-in its CCA Program over the course of three stages:

1. Participant (Municipal) Accounts
2. Commercial and Industrial Accounts
3. All Remaining Accounts

This approach provides the Authority with the ability to start slow, address any problems or unforeseen challenges on a small manageable program before gradually building to full program integration for an expected 111,000 plus customer base. This approach also provides for the Authority and its primary contractors to address all system requirements (billing, collections, payments) under a phase-in approach to minimize potential exposure to uncertainty and financial risk by introducing the Program on a small, highly manageable scale prior to expanding the Program in deliberate, incremental stages.

Phase 1 – Participant Accounts

Phase 1 of the Program would be targeted to begin on January 1, 2010; subject to the following conditions being met: CPUC approval of the Authority's Implementation Plan; final approval of the Program by the Parties (via the JPA Agreement and approval of Program Agreement No. 1); completion of all necessary implementing agreements including those with suppliers, the investor-owned utilities, and potentially others; and execution of the Authority's start-up staffing plan.

Phase 1 will consist solely of the direct electric accounts of the Program Participants' (Member cities and Marin County) loads. Under this approach it is expected that the opt-out rate for accounts (and load) for the Marin Communities will be zero percent. Of the participating accounts, it is assumed that all accounts will participate in the Authority's 100% Green Tariff. This would result in approximately 600 accounts representing a load of 21 GWh annually, all of which would be served with 100% renewable energy supplies. Energy supply for Phase 1 would be met via agreements entered into by the Authority with third-party energy service providers.

Phase 2 – Large Accounts

Phase 2 of the Program is targeted to begin approximately five months after Phase 1; however, the Authority's Board of Directors would have the authority to potentially adjust this starting date depending upon the performance of the Program under Phase 1. The intent is to ensure that the Program is operating properly, including proper procurement and delivery of electricity, as well as billing and receivables from the Member Participants' own loads prior to rolling the Program out to commercial customers.

Phase 2 of the Program is focused on medium and large electric users; those accounts that typically have demands in excess of 50 kW, in addition to the customers already included in Phase 1.[8] For modeling purposes it is assumed that 100% of direct access customers and 10 percent of bundled service customers will opt-out of the CCA Program entirely and that the following tariff-specific participation rates will apply to remaining customers included in Phase 2, subject to marketing efforts of the program:

- Medium Commercial: 70% participation in 100% Green; 30% participation in Light Green Tariff;
- Large Commercial: 5% participation in 100% Green; 95% participation in Light Green Tariff;
- Industrial: 5% participation in 100% Green; 95% participation in Light Green Tariff; and
- Agricultural: 20% participation in 100% Green; 80% participation in Light Green Tariff.

This provides for an estimate incremental Phase 2 customer class of approximately 1,200, with an annual load of 364 GWh.

Phase 3 – All Accounts

The final Phase (Phase 3) provides for all electric customers within the service territory of the Authority's Participating Members to have the option of participating in the CCA Program. Within Phase 3, it is expected that all direct access customers and 10% of eligible bundled service customers will opt out of the CCA program. Of the 90% of Phase 3 customers that remain with the program, it is expected that 70% will elect to participate in the 100% Green Tariff. The remaining 30% of participating Phase 3 customers are assumed to participate in the Light Green Tariff due to cost sensitivity. This represents a significant increase in the number of customers and the overall energy requirements for the program as the incremental growth for Phase 3 is approximately 109,000 customers and 837 annual GWh.

The assumed start date for Phase 3 of the Program is eight months after the commencement of Phase 2, again subject to the final review and approval of the Authority's Board of Directors.

Resource Plan Overview

The criteria used to guide development of the proposed resource plan includes the following:

- Environmental responsibility and commitment to renewable resources
- Price/Rate Stability
- Reliability and maintenance of adequate reserves
- Cost effectiveness

[8] Phase 2 would include the A-10, E-19 and E-20 customer classes.

To meet these objectives and the applicable regulatory requirements, the Authority's resource plan should include a diverse mix of generation, power purchases, renewable energy, new energy efficiency programs, demand response, and distributed generation. A diversified resource plan minimizes risk and volatility that can occur from over-reliance on a single resource type or fuel source. The ultimate goal of the Authority's resource plan is to maximize use of renewable resources subject to economic and operational constraints. The result is a resource plan that would source over 80% of the resource mix from renewable resources by 2014. The planned resource mix is initially comprised of power purchases from third party electric suppliers and, in the longer-term, also includes renewable generation assets owned and/or controlled by the Authority.

The Authority's renewable generation, which would be directly owned by the Authority or controlled under long-term power purchase agreement with a proven public power developer, would provide a portion of the Authority's electricity requirements on a cost-of-service basis. Electricity purchased under a cost-of-service arrangement should be more cost-effective than purchasing renewable energy from third party developers, which will allow the Program to pass on cost savings to its customers through competitive generation rates. As discussed in Chapter 4, the amount of generation proposed to be financed by the Authority will be a influenced by security requirements necessary for issuance of revenue bonds needed to finance the project. Once the Program demonstrates it can operate successfully for a number of years, additional generation investments would be expected. Additional refinement of security requirements in consultation with the Marin Communities' financial advisors, investment bankers, attorneys, and potentially with customer input may increase the assumed debt carrying capacity of the Program and enable greater investment than shown in this plan.

As an alternative to direct investment, the Authority may partner with an experienced public power developer and enter into a long-term (20-to-30 year) power purchase agreement that would support the development of new renewable generating capacity within Marin County or at an alternative location within the Greater Bay Area. Such an arrangement could be structured to virtually eliminate the Program's operational risk associated with capacity ownership while providing Program customers with all renewable energy generated by the facility under contract. This option may be preferable to the Authority as it works to achieve increasing levels of renewable energy supply to its customers.

The Authority's resource plan will integrate supply-side resources with programs that will help customers reduce their energy costs through improved energy efficiency and other demand-side measures. As part of its integrated resource plan, the Authority would actively pursue, promote and ultimately administer a variety of customer energy efficiency programs that can cost-effectively displace supply-side resources. Included in this plan is a targeted deployment of over 13 MW of distributed solar by 2019.

Beginning on January 1, 2007, all owners of distributed solar capacity that applied for state-sponsored rebates were obligated to participate in their respective utility's time-of-use rate tariff. The significantly higher rates in these tariffs have discouraged distributed solar installations in the first quarter of 2007 relative to the same time period in 2006. In fact, on May

8, 2007 the Los Angeles Times reported a 78% reduction in solar rebate requests during this three month period, year-over-year, which has been substantially attributed to the time-of-use rate mandate. Public Utilities Code, Section 2851(a)(4) specifies that time-of-use rate structures must create "the maximum incentive for ratepayers to install solar energy systems." On May 16, 2007, President Peevey of the CPUC issued a Proposed Decision in Rulemaking 06-03-004 staying the time-of-use rate mandate until such time that the Commission is able to develop a new time-of-use rate tariff that meets the expressed requirement of Section 2851.

Unlike customers of the investor-owned utilities who own distributed solar capacity, customers of the Authority will not be constrained by PG&E's time-of-use rate structures, as the Authority may design rates at the discretion of its Board of Directors. The Authority would be free to maximize solar installations without a for-profit entity's concern that reducing customer net energy consumption would detract from shareholder profits. With this in mind, the Authority may develop unique rate schedules that create specific incentives for owners of distributed renewable capacity, ensuring that distributed renewable capacity additions continue to occur throughout its jurisdiction. Through the creative development of rate structures that encourage the installation of distributed renewable resources and support ongoing operation of these systems, the Program can ensure high levels of distributed renewable installation as a form of energy efficiency. Over time, the Authority will be able to modify these rate structures, based on customer behavior, to achieve desired levels of distributed renewable capacity.

The Authority's proposed resource plan for the years 2010 through 2019 is summarized in the following table.

Marin Power Authority
Energy Balance
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Marin Demand (GWh)										
Retail Demand	-267	-1,234	-1,240	-1,246	-1,252	-1,259	-1,265	-1,271	-1,278	-1,284
Distributed Generation	6	8	10	12	13	15	17	18	19	19
Energy Efficiency	0	4	11	15	15	15	15	15	15	16
Losses and UFE	-18	-86	-85	-85	-86	-86	-86	-87	-87	-87
Total Demand	-280	-1,308	-1,304	-1,305	-1,309	-1,314	-1,319	-1,325	-1,330	-1,337
Marin Supply (GWh)										
Renewable Resources										
Generation	0	0	0	0	794	794	794	794	794	794
Power Purchase Contracts	145	858	855	856	191	195	198	203	206	212
Total Renewable Resources	145	858	855	856	985	989	992	997	1,001	1,006
Conventional Resources										
Generation	0	0	0	0	0	0	0	0	0	0
Power Purchase Contracts	135	450	449	449	324	325	326	328	329	331
Total Conventional Resources	135	450	449	449	324	325	326	328	329	331
Total Supply	280	1,308	1,304	1,305	1,309	1,314	1,319	1,325	1,330	1,337
Energy Open Position (GWh)	0	0	0	0	0	0	0	0	0	0

Supply Requirements

The starting point for the Authority's resource plan is a projection of participating customers and associated electric consumption. Projected electric consumption is evaluated on an hourly basis, and matched with resources best suited to serving the aggregate of hourly demands or the program's "load profile". As a basis for the customer forecast, the Marin Communities requested historic load data for each of their respective jurisdictions. This data was organized and analyzed, becoming the starting point from which an annual load forecast was developed. An annual growth rate of 0.5%, consistent with Marin's population growth rate, was applied to this data, resulting in a long-term annual load forecast for the county and cities. From the annual load forecast, hourly demands were calculated based on historic usage profiles for the county and cities. The electric sales forecast and load profile will be affected by the Authority's plan to introduce the program to customers in phases and the degree to which customers choose to remain with PG&E during the customer enrollment and opt-out periods. The Authority's phased roll-out plan and assumptions regarding customer participation rates are discussed below.

Customer Participation Rates

Customers will be automatically enrolled in the Authority's electricity program unless they opt-out during the customer notification process conducted during the 60-day period prior to enrollment and continuing through the 60-day period following commencement of service. The Authority anticipates an overall customer participation rate of 100 percent during Phase 1, when service is being offered to the service accounts that are affiliated with the Authority's participating members (municipal accounts). It is assumed that each of these service accounts will participate in the Authority's 100% Green Tariff. Participation rates are expected to be 90 percent of bundled service customers and 0 percent of direct access customers during Phases 2 through 3 based on experience with similar opt-out style municipal aggregation programs developed in other states; these have ranged from 5 percent in Massachusetts to 10 percent in Ohio. The participation rate is not expected to vary significantly among customer classes, in part due to the fact that the Authority will offer two distinct rate tariffs that will address the needs of cost-sensitive customers within the Marin Communities as well as the needs of both residential and business customers that prefer a highly renewable energy product. These participation rates should also be supported by the Authority's focused marketing efforts directed towards commercial and industrial customers who may otherwise be more inclined to remain with a known entity like PG&E. The assumed participation rates will be refined as the Authority's public outreach efforts continue to develop and experience is gained by other California CCA programs.

Customer Forecast

Once customers enroll in each implementation phase, they will be switched over to service by the Authority on their regularly scheduled meter read date over an approximately thirty day period. Approximately 19 service accounts per day will be switched over during the first month of service. For Phase 2, the number of accounts switched over to CCA service will double to about 40 accounts per day. However, during Phase 3, the Authority's customer account systems must be capable of processing customer enrollments of over 3,600 accounts per day. The number of accounts served by the Authority at the end of each phase is shown in the table below.

Marin Power Authority
Enrolled Retail Service Accounts
Phase-In Period (End of Month)

Marin Customers	**Jan-10**	**May-10**	**Jan-11**
Residential	2	2	97,443
Small Commercial	341	339	11,704
Medium Commercial	32	1,062	1,067
Large Commercial	3	156	157
Industrial	-	11	11
Street Lighting & Traffic	186	186	542
Ag & Pump.	1	1	177
Total	565	1,757	111,101
Customer Additions	565	1,192	109,344

The forecast of service accounts (customers) served by the Authority for each of the next ten years is shown in the following table.

Marin Power Authority
Retail Service Accounts (End of Year)
2010 to 2019

Marin Customers	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Residential	2	97,443	97,930	98,420	98,912	99,406	99,903	100,403	100,905	101,409
Small Commercial	341	11,704	11,762	11,821	11,880	11,940	11,999	12,059	12,120	12,180
Medium Commercial	1,062	1,067	1,073	1,078	1,083	1,089	1,094	1,100	1,105	1,111
Large Commercial	156	157	158	159	159	160	161	162	163	164
Industrial	11	11	11	11	11	11	11	11	12	12
Street Lighting & Traffic	186	542	545	548	550	553	556	559	561	564
Ag & Pump.	1	177	178	179	180	181	182	183	183	184
Total	1,759	111,101	111,657	112,215	112,776	113,340	113,907	114,476	115,049	115,624

Sales Forecast

The Authority's forecast of kWh sales reflects the roll-out and customer enrollment schedule shown above. The annual electricity needed to serve the Authority's retail customers increases from approximately 280 GWh in 2010 to just over 1,300 GWh at full roll-out in 2011. Annual energy requirements are shown below.

Marin Power Authority
Energy Requirements
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Marin Demand (GWh)										
Retail Demand	267	1,234	1,240	1,246	1,252	1,259	1,265	1,271	1,278	1,284
Distributed Generation	-6	-8	-10	-12	-13	-15	-17	-18	-19	-19
Energy Efficiency	0	-4	-11	-15	-15	-15	-15	-15	-15	-16
Losses and UFE	18	86	85	85	86	86	86	87	87	87
Total Load Requirement	280	1,308	1,304	1,305	1,309	1,314	1,319	1,325	1,330	1,337

Capacity Requirements

The CPUC's resource adequacy standards applicable to the Authority require a demonstration one year in advance that the Authority has secured physical capacity for 90 percent of its projected peak loads for each of the five months May through September, plus a minimum 15 percent reserve margin. On a month-ahead basis, the Authority must demonstrate 100 percent of the peak load plus a minimum 15 percent reserve margin.

A portion of the Authority's capacity requirements must be procured locally, from the Greater Bay area as defined by the CAISO and antother portion must be procured from outside the Greater Bay Area. The Authority would be required to demonstrate its local capacity requirement for each month of the following calendar year. The local capacity requirement is a percentage of the total (PG&E service area) local capacity requirements adopted by the CPUC based on the Authority's forecasted peak load. The formula is as follows:

Authority Local Capacity Requirement = [Authority Capacity Requirement/Total PG&E Service Area Capacity Requirement]*Total Local Capacity Requirement in PG&E's Service Area

The Authority must demonstrate compliance or request a waiver from the CPUC requirement as provided for in cases where local capacity is not available. If necessary, the Authority would be able to request relief from the local procurement obligation with a demonstration that it has made every commercially reasonable effort to contract for local capacity resources. A waiver request would have to demonstrate that the Authority actively sought products and either received bids with prices in excess of an administratively determined local attribute price ($40 to $73 per kW-year) or received no bids.

The waiver applies to Commission-imposed penalties only. If deficient, the Authority would be responsible for any applicable backstop procurement costs even if it received a waiver from penalties. The CAISO would procure local capacity as a backstop and would charge a fee based on its costs of procuring the capacity. For 2007, the backstop cost was approximately $73 per kW-year.

The Authority's first resource adequacy filing could take place as early as October 2009, according to the schedule established by the CEC for evaluating statewide resource adequacy based on resource plans filed by all load serving entities in the state. The forward resource adequacy requirements for 2010 through 2012 are shown in the following tables.

Marin Power Authority
Summer Peak Loads
(MW)
2010 to 2012

Month	2010	2011	2012
January	3	222	220
February	4	237	236
March	3	193	191
April	3	188	186
May	66	174	172
June	68	200	198
July	64	195	193
August	66	221	219
September	73	205	203
October	69	205	203
November	67	227	225
December	61	222	220

Marin Power Authority
Forward Capacity and Reserve Requirements
(MW)
2010 to 2012

Month	2010	2011	2012
January	4	256	253
February	4	273	271
March	4	222	219
April	4	216	213
May	76	200	197
June	79	230	228
July	74	224	222
August	75	254	251
September	84	236	234
October	79	235	233
November	77	261	259
December	70	255	253

The Authority's plan would ensure sufficient reserves are procured to meet its peak load at all times. The Authority's annual capacity requirements are shown in the following table.

Marin Power Authority
Capacity Requirements
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Demand (MW)										
Retail Demand	72	228	229	230	231	232	234	235	236	237
Distributed Generation	(4)	(5)	(6)	(8)	(9)	(10)	(12)	(12)	(13)	(13)
Energy Efficiency	-	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Losses and UFE	5	16	15	15	15	15	15	15	15	15
Total Net Peak Demand	73	237	236	235	234	234	234	235	235	236
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	11	36	35	35	35	35	35	35	35	35
Capacity Requirement Including Reserve	84	273	271	270	270	269	269	270	270	272

Local capacity requirements are a function of the PG&E area resource adequacy requirements and the Authority's projected peak demand. The Authority would need to work with the CPUC's Energy Division and potentially staff at the California Energy Commission to obtain the data necessary to calculate the Authority's monthly local capacity requirement. A preliminary estimate of the Authority's annual local capacity requirement for the ten year planning period ranges from approximately 32 to 102 MW as shown in the following table.

Marin Power Authority
Local Capacity Requirements
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PG&E Planning Area System Peak (MW)	22,425	22,717	23,012	23,311	23,614	23,921	24,232	24,547	24,866	25,189
Total Capacity Requirement (115%)	25,789	26,124	26,464	26,808	27,156	27,509	27,867	28,229	28,596	28,968
Authority Peak (MW)	73	237	236	235	234	234	234	235	235	236
Authority Share of Planning Area	0.3%	0.9%	0.9%	0.9%	0.9%	0.9%	0.8%	0.8%	0.8%	0.8%
Local Capacity Requirement - Greater Bay Area	4,896	4,959	5,024	5,089	5,155	5,222	5,290	5,359	5,429	5,499
Local Capacity Requirement - Other PG&E	6,232	6,313	6,395	6,478	6,562	6,648	6,734	6,822	6,910	7,000
Authority Local Capacity Requirement Greater Bay	14	45	45	45	45	44	44	45	45	45
Authority Local Capacity Requirement Other PG&E	18	57	57	57	57	57	57	57	57	57

Renewable Portfolio Standards Energy Requirements

Basic RPS Requirements

As a CCA, the Authority would be required by law and ensuing CPUC regulations to procure a minimum percentage of its retail electricity sales from qualified renewable energy resources. Under the California renewable portfolio standards (RPS) program and policies established in the state's Energy Action Plan, the Authority must generally increase its percentage utilization of renewable energy by no less than 1 percent per year and achieve a minimum of 20 percent by 2010. For purposes of determining the Authority's renewable energy requirements, the same standards for RPS compliance that are applicable to the distribution utilities are assumed to apply to the Authority.

The Commission has so far ruled that CCAs must comply with five fundamental aspects of the RPS program: 1) meeting the 20 percent requirement by 2010; 2) increasing their renewable sales by at least 1 percent per year; 3) reporting their progress to the Commission; 4) utilizing flexible compliance mechanisms; and 5) being subject to penalties and penalty processes. Additional specifics of how CCAs, unregulated energy service providers and multi-jurisdictional utilities are to comply with the RPS and how their compliance may be different in some respects than the rules that are applicable to the distribution utilities are being addressed in the ongoing CPUC proceeding, R.06-02-012. The rules ultimately adopted for CCAs may provide greater flexibility than assumed in this plan, for instance, by allowing use of short-term contracting or unbundled renewable energy certificates for RPS compliance. Future resource plans should incorporate any changes in these assumptions that result from the Commission's rulemaking process.

RPS Compliance Rules

CPUC Decision No. 04-06-014 clarifies the methodology for calculating the annual renewable energy requirements needed to comply with the RPS. In that decision, the Commission defines two related terms to measure a load serving entity's progress toward meeting its RPS obligations. The "Annual Procurement Target" (APT) is the total amount of renewable energy needed to meet the requirement to increase renewable procurement by at least 1 percent of retail sales per year, subject to Commission rules for flexible compliance. It is the sum of the baseline, representing renewable generation needed to continue to satisfy obligations under the RPS targets of previous utilities years, and the "Incremental Procurement Target" (IPT), which is at least 1 percent of the previous utilities year's total retail electrical sales.

The CPUC's flexible compliance rules allow a load serving entity to defer up to 25 percent of the IPT without explanation, as long as the shortfall is made up within three years. Shortfalls greater than 25 percent of IPT will be permitted upon demonstration of one or more of the following: 1) insufficient response to a request-for-offers; 2) contracts in hand that will make up the deficit in future years; 3) inadequate public goods funds to cover above market renewable contract costs; and 4) seller non-performance. Flexible compliance does not currently extend the

20 percent by 2010 requirement. Noncompliance will result in penalties of 5 cents per kWh, capped at $25 million per year.

The Authority's Renewable Portfolio Standards Requirement

Because the Authority will have no baseline of renewable energy procurement (i.e., no existing contracts or resources) and no prior retail electrical sales, its first year APT calculated as described above is zero. In 2011, the expected second year of the program, the Authority must meet the full 20 percent renewable standard (based on 2010 retail sales). The Authority's annual RPS requirements are shown in the table below.

Marin Power Authority
RPS Requirements
(MWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales	261,264	1,222,384	1,219,080	1,219,581	1,223,812	1,228,073	1,232,365	1,238,339	1,242,859	1,249,170
Baseline	-	-	52,253	244,477	243,816	243,916	244,762	245,615	246,473	247,668
Incremental Procurement Target	-	52,253	192,224	(661)	100	846	852	858	1,195	904
Annual Procurement Target	-	52,253	244,477	243,816	243,916	244,762	245,615	246,473	247,668	248,572
% of Current Year Retail Sales		4%	20%	20%	20%	20%	20%	20%	20%	20%

The Authority's Renewable Energy Goals

The Authority would target a 56% renewable energy percentage during the first two phases of program operations, based on projected participation in the program's 100% Green and Light Green Tariffs, and would then further exceed the RPS as it builds towards more than 80% by 2014. Beyond 2014, the Authority intends to increase its procurement of renewable energy supplies subject to economic and operational constraints. It is the long-term goal of the Marin Power Authority to procure 100% of its energy supplies from renewable sources. The Authority would therefore significantly exceed the minimum RPS requirements as shown below; provided that the competitive wholesale market provides qualified responses to the Authority's resource solicitations.

Marin Power Authority
RPS Requirements and Program Renewable Energy Targets
(MWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales (MWh)	261,264	1,222,384	1,219,080	1,219,581	1,223,812	1,228,073	1,232,365	1,238,339	1,242,859	1,249,170
Annual RPS Target (Minimum MWh)	-	52,253	244,477	243,816	243,916	244,762	245,615	246,473	247,668	248,572
Program Target (% of Retail Sales)	56%	70%	70%	70%	81%	81%	81%	81%	81%	81%
Program Renewable Target (MWh)	**145,048**	**857,657**	**855,339**	**855,691**	**985,245**	**988,676**	**992,131**	**996,940**	**1,000,579**	**1,005,660**
Surplus In Excess of RPS (MWh)	**145,048**	**805,404**	**610,862**	**611,875**	**741,329**	**743,914**	**746,517**	**750,467**	**752,911**	**757,088**
Annual Increase (MWh)	145,048	712,609	(2,318)	352	129,555	3,431	3,456	4,809	3,639	5,081

Resources
The Authority would seek to maximize use of its own cost-based renewable generation resources in its resource plan, subject to the Authority's ability to finance or otherwise obtain an entitlement to such projects. The ability to procure output from or invest capital in generation resources financed with tax-exempt debt is an important factor in the Authority's ability to increase use of renewable energy while offering rates that are competitive with PG&E. Power purchases from renewable and the cleanest non-renewable (natural gas-fired) resources would supply the remaining majority of the resource mix. The Authority's electric portfolio would be managed by a third party electric supplier, at least during the initial implementation period. Through a power services agreement, the Authority would obtain full requirements electric service for the Authority's retail customers, including providing for all electric and ancillary services and the scheduling arrangements necessary to provide delivered electricity to the retail customers' end use meters through 2013. A subsequent power services agreement would provide for integration of the Authority's renewable generation or power purchase contracts; or alternatively, the Authority may gain the expertise by that time to manage the portfolio with internal staff.

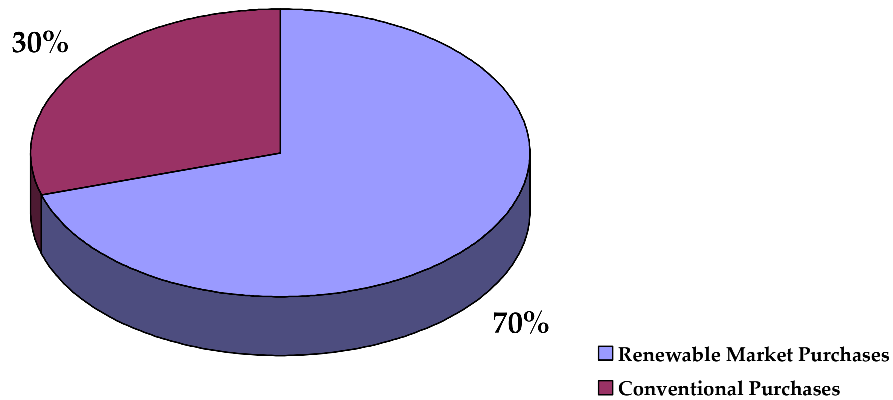
The Authority's resource plan anticipates the development of a diverse renewable resource portfolio, which includes contributions from four commercially viable generating sources with aggregated production characteristics that are consistent with the Marin load profile:

- Wind – 30% (of renewable supply portfolio)
- Solar – 25%
- Biomass and/or Geothermal – 55%

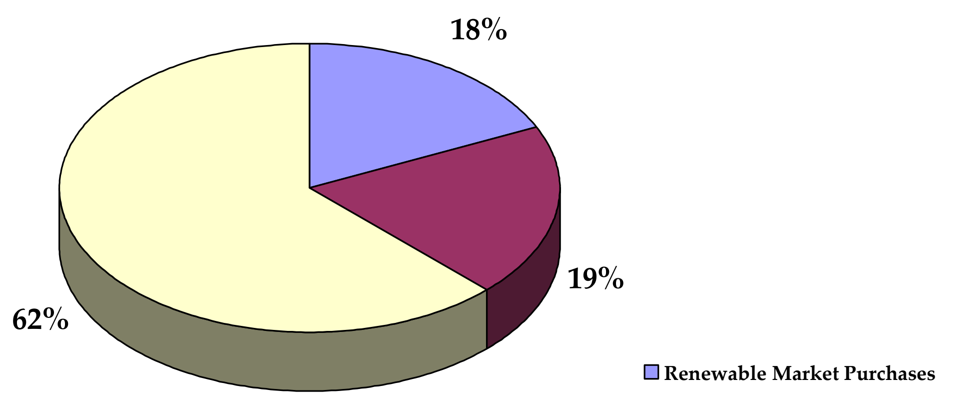
As part of its renewable resource portfolio, the Authority plans to develop both a wind and biomass generation resource within the PG&E service area planned to be online by 2014. The plan calls for initial development of 200 MW of these resources to meet approximately 62% of the Authority's annual electricity requirements. It is likely that additional investment would be made after several years of successful operating experience. Wind and biomass technologies were selected for this plan due to the maturity of the respective technologies and the fact that wind and biomass are generally the lowest cost renewable resources currently available. However, other technologies such as solar and geothermal should also be investigated as the Program moves forward. Approximately 18% of the total resource mix is anticipated to come from power purchases from third party renewable energy developers. Non-renewable baseload, peaking and shoulder load requirements would generally be met with power purchase contracts for the balance of this planning horizon.

The planned resource mix for 2011 and 2017 are shown in the figures on the following page. It is important to note that the portions of the Authority's supply portfolio from renewable energy sources should be considered "carbon free" for the purpose of comparison to a utility supply portfolio.

Marin Power Authority 2011 Resource Mix



Marin Power Authority 2017 Resource Mix



Purchased Power

Power purchased from utilities, power marketers, public agencies, and/or generators will be the exclusive source of supply from 2010 to 2013 and will remain a significant source of power supply after the Authority's initial renewable generation begins producing electricity, anticipated to be 2014. During the period from 2009 – 2013, the Authority would obtain all of its electricity from a third party electric provider under a full requirements power supply agreement, and the supplier will be responsible for procuring a mix of power purchase contracts, including specified renewable energy targets, to provide a stable and cost-effective resource portfolio for the Program.

Initially, the Program's third party electric supplier will be responsible for managing the overall supply portfolio. Details of the electric supply portfolio and risk management practices that will be employed by the Program's electric supplier will be established as the contract is negotiated with the selected electric supplier. It is anticipated that a mix of short and long term power purchases will be used to meet the hour-by-hour demand requirements of the Authority's customers, and that prices would be predominantly fixed for the contract term.

Renewable Resources

To meet its aggressive renewable energy goals, the Authority would initially secure power purchase contracts for qualified renewable energy resources at an amount equal to 56% of retail demand, which equates to approximately 858,000 MWh by 2011. To qualify as eligible for California's RPS, a generation facility must use one or more of the following renewable resources or fuels:

- Biomass
- Biodiesel
- Fuel cells using renewable fuels
- Digester gas
- Geothermal
- Landfill gas
- Municipal solid waste
- Ocean wave, ocean thermal, and tidal current
- Photovoltaic
- Small hydroelectric (30 MW or less)
- Solar thermal
- Wind

Renewable technologies that are predominant and generally commercially available are wind, geothermal, biomass, land fill gas, and solar (thermal or photovoltaic). Studies sponsored by the CEC show that over 7,000 MW of eligible renewable resources are economically developable statewide by 2010, and a study sponsored by the CPUC indicated nearly 50,000 MW of renewable resource potential could be utilized by 2020.[9] The vast majority of the resource potential identified by the CEC is located in Southern California, concentrated in four specific

---

[9] *Strategic Value Analysis for Integrating Renewable Energy Technologies in Meeting Target Renewable Penetration; In Support of the 2005 Integrated Energy Policy Report; Davis Power Consultants, June 2005.* Costs are in 2005 dollars. Resources identified as being economically developable by the CEC were those found to have positive impacts on the transmission system, if developed and for which the levelized costs are estimated to be at or below a market price benchmark of 6.05 cents per kWh. The referenced CPUC study is *Achieving A 33% Renewable Energy Target; J.Hamrin, R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger; November 2005.*

areas: Tehachapi area and Riverside County wind resources (2,800 MW), utility-scale solar in the Southern California deserts (1,000 MW), and geothermal in the Imperial Valley (1,600 MW). There are an estimated 450 MW of resources in the PG&E territory economically developable by 2010, primarily represented by wind resources in Solano and Alameda Counties (400 MW) and geothermal (45 MW) near the Geysers.

Near Term Renewable Potential

While renewable resource potential within the state is vast, the lack of existing transmission facilities necessary to interconnect the renewable resource areas – which are typically far from population centers – and the lack of sufficient transfer capability on key transmission paths to enable delivery to load centers may be a limiting factor in acquiring low cost renewable energy to meet the Authority's resource planning goals (until the transmission system is expanded). Existing transmission constraints generally limit the quantity of renewable energy that can be delivered to the Authority's customers from resources located outside of the larger host utility (PG&E, SCE, SDG&E) service territory, without causing transmission congestion charges to be incurred. Considering transmission constraints and current transmission expansion plans of the investor owned utilities, there are an estimated 14 million MWh per year of economically developable renewable resources currently available (by 2010) as shown in the following table, with about 2.6 million MWh of this annual production potential located within the PG&E service territory.

Resources Identified for Potential CCA Development by 2010, Considering Existing and Planned Network Transmission System Capacity (MWh)

Resource Type	PG&E Area	SCE Area	SDG&E Area[10]
Geothermal	1,576,800	0	5,085,180
Wind	525,236	4,780,800	394,200
Biomass	525,000	1,094,562	156,366
Total	**2,627,036**	**5,875,362**	**5,635,746**
Source: Community Choice Aggregation Demonstration Project; Renewable Resource Development Roadmap; Navigant Consulting, Inc, June 2006.			

Ideally, the Authority would be able to procure renewable energy locally, or at least from within the PG&E service area. Transmission capacity for energy imports from outside the host utility service area (PG&E) is available during only certain times of the year, and electricity transmitted from points outside of the region would be subject to potential charges for use of congested transmission lines. Congestion charges will become a more significant economic factor as the CAISO transitions from the current zonal congestion pricing model to a nodal model as it implements its Market Redesign and Technology Update (MRTU).[11] The ideal energy source would be located within the County, near the load center. The next best

[10] The geothermal resources are located in Imperial Valley and will be deliverable to San Diego area loads following completion of Phase 1 of SDG&E's proposed Sunrise Powerlink in 2010. Wind resources in Eastern San Diego County are planned to be connected via tap lines to the Sunrise Powerlink.

[11] Under the current zonal model, there are potential congestion costs for transferring electricity between any of the three zones within California (NP15, ZP26 and SP15). The nodal model will expand the number of congestion pricing points, creating thousands of locational pricing nodes.

alternative would be for the resource to be located outside the CCA's boundaries but within or deliverable to the PG&E service territory. A study prepared for Marin County identified nearly 850 MW of renewable resource potential within the County, capable of producing approximately 1,300 GWh per year.[12] Considering that PG&E is expected to need over 6.5 million MWh per year of additional renewable energy procurement to meet its RPS obligation by 2010, the Authority will look first to local renewable resources and then to procurement of renewable energy from outside the area. The Authority may also supplement its procurement of physical resources with purchases of renewable energy certificates, which allow for the purchase of the renewable attributes of electricity generated by a renewable resource without regards to physical delivery to loads.[13]

For planning purposes, the Authority should anticipate procurement from the following types of large scale renewable resources in the near term, which would require little or no transmission expansion to ensure deliverability:

- Local resources (solar, wind, biogass, biomass)
- Wind resources in Solano County
- Existing Qualifying Facilities with expiring PG&E contracts
- Expansion and re-powering of wind resources in Alameda County
- Geothermal in Lake and Sonoma Counties
- Local biomass projects
- Renewable Energy Certificates

Medium And Long Term Renewable Potential

In the medium to long term, the Program will be able to utilize the transmission expansion projects that are underway by PG&E, SCE, and potentially other utilities and transmission owners/developers in the West, designed to expand access to renewable resource areas. PG&E, as well as any other utility, must offer access to its transmission system to generators and other market participants and provide transmission service comparable to the service it provides itself, according to well established open access regulations promulgated by the Federal Energy Regulatory Commission (FERC).[14] The CAISO administers access to PG&E's transmission system on a nondiscriminatory basis in accordance with tariffs on file with the FERC. As of January 2008, over 38,000 MW of renewable resources have applied for transmission interconnections with the CAISO.[15] According to the CAISO, about one half of all projects in the queue ultimately are developed. These projects represent proposed renewable projects that the Authority could potentially use to meet its renewable energy requirements, once the necessary transmission upgrades are completed.

[12] Increasing Renewable Energy Resources in the County of Marin, Jody London Consulting, November 11, 2007.
[13] The cost of potential congestion charges has been included in the risk analysis presented in Chapter 4.
[14] The open access framework for transmission is set forth in a series of orders by the Federal Energy Regulatory Commission: FERC Orders 888, 889, 889A and 890.
[15] 2008 CAISO Transmission Plan: A Long-Term Assessment of the California ISO's Controlled Grid (2008-2018), California Independent System Operator, January 2008.

PG&E has plans in place to invest up to $3.0 billion in new transmission infrastructure over the next decade, and has identified four major transmission projects specifically designed to expand access to renewable resources.[16] These four projects are projected to come on-line between 2008 and 2010, pending CAISO approval, at a total estimated cost ranging between $171 and $455 million. These four renewable-focused transmission projects are identified in the following table.

PG&E Transmission Expansion Plan Summary

Project Title	Purpose and Benefit	County	Project Scope	CAISO Approval Status	Expected Capacity Increase (MW)	Cost Range ($)	Targeted In-Service Date
Vaca Dixon – Contra Costa 230kV Reinforcement	Access Resource	Solano	Reconductor 230 kV Lines	Not Yet	Approx. 300 MW when completed w/other projects	20-50M	May 2008
Bogue Junction Reconfiguration	Access Resource	Sutter	Reconfigure 115 kV lines at Bogue Junction	Not Yet	Not Published	1-5M	May 2009
Midway – Gregg 500kV Line	Access Resource	Fresno, Kings & Kern	Increase Transmission Capacity to Access Resources	Not Yet	Approx. 1,250 MW	100-200M	2010
Vaca Dixon – Sobrante – Moraga 230kV Reinforcement	Access Resource	Solano and Contra Costa	Increase Transmission Capacity to Access Resources	Not Yet	Approx. 300 MW when completed w/other projects	50-200M	May 2010

In its Plan, PG&E notes that these projects are at "conceptual studying stages", and, as a result, definitive conclusions should not be drawn with respect to project details or timing. However, there is no doubt that PG&E will target certain renewable transmission projects for completion to further its achievement of the state's renewable portfolio standard, which mandates 20% renewable energy sales by 2010 and potentially 33% by 2020.

In addition to these specific projects/focus areas, PG&E is also involved in studying various other projects, such as the development of electric transmission to accommodate the transfer of 4,000 MW of wind generation from the Tehachapi Region. Based on CPUC Decision 04-06-010, the Tehachapi Collaborative Study Group was formed "to develop a comprehensive transmission development plan for the phased expansion of transmission capabilities in the Tehachapi area." Membership in this group includes PG&E, SCE, the CEC, the CPUC, the CAISO, wind energy developers and other stakeholders. Based on its studies, PG&E identified three transmission development alternatives that would accommodate importing 2,000 MW of wind generation from the Tehachapi region to northern California (another 2,000 MW would be available for southern import). A preferred alternative has been identified (new Tesla-Gregg

[16] PG&E 2006 Electric Grid Expansion Plan, December 29, 2006.

500 kV line and new Gregg-Midway 500 kV line, which was previously noted) and is still in PG&E's planning/study phases.

Other projects under consideration by PG&E include those considered by the Northwest Transmission Assessment Committee (NTAC), which would bring renewable and other generating resources to California from Canada and the Pacific Northwest, a submarine transmission interconnection to British Columbia from northern California and the Frontier Line, which would connect California to Wyoming capacity markets (primarily wind and "clean" coal). These projects have not yet been fully developed and are still being studied by PG&E.

As noted above, the Authority would have the same access as PG&E to this transmission once the projects are completed. For mid and long term planning purposes, the Authority should anticipate procurement from the following types of large scale renewable resources[17]:

- Wind imports from the Tehachapi Area
- Wind imports from the Pacific Northwest
- Geothermal imports from Nevada
- Geothermal imports from the Imperial Valley
- Solar CSP imports from Southern California (Riverside and San Bernardino Counties)

Although this resource plan identifies likely resource types and locations, it is not possible to predict what projects might be proposed in response to the Authority's solicitations for renewable energy or that may stem from discussions with other public agencies. Renewable projects that are located virtually anywhere in the Western Interconnection can be considered as long as the electricity is deliverable to the CAISO control area, as required to meet the Commission's RPS rules and any additional guidelines ultimately adopted by the Authority's Board of Directors. The costs of transmission access and the risk of transmission congestion costs would need to be considered in the bid evaluation process if the delivery point is outside of the Authority's load zone, as defined by the CAISO.

Initially, the electric supplier selected for the Program will be responsible for meeting the specified renewable energy requirements under a full requirements electricity agreement. In the longer term, the Authority would request proposals directly from renewable developers to meet its renewable energy requirements, and responses to the solicitations would determine the specific resource types and locations that will be utilized. Actual procurement of renewable resources can be conducted through a competitive solicitation, either directly by the Authority or in conjunction with another public agency. Once formed, the Authority can explore opportunities to partner with other public agencies, such as the Sacramento Municipal Utility District (SMUD) or the Northern California Power Agency (NCPA), that are currently developing renewable resources.

It bears mentioning that the Authority will be in competition for renewable resources with the three investor owned utilities, which together require nearly 12 million MWh annually to meet

[17] In the long term, new technologies such as wave or tidal energy may become economically feasible as well.

their RPS requirements by 2010. Over the longer term, the transmission expansion plans of the utilities will provide additional resource options for the Authority. The Authority, working with third party electric suppliers, will need to be aggressive in pursuing the renewable resources that are currently available to ensure that PG&E and the other utilities do not lock up the most economic resources for their own portfolio needs during the early years of the Program.[18] In contrast to PG&E, which is motivated by regulatory compliance with the Renewable Portfolio Standards, the Authority would elevate procurement and development of renewable energy as its primary mission, proactively seeking out opportunities to develop local resources and partnering with private developers and other public agencies.

Planned Renewable Generation Resources

The resource plan includes the anticipated development by the Authority of wind and biomass resources located within the PG&E service territory. These resources are planned to become operational in 2014. It should be understood that the specific resource types, locations and timing will be the result of a competitive solicitation process and may differ from those presented here. Possible locations for new wind development include wind resource areas in Solano County, the Altamont wind resource area in Alameda County and potentially the Tehachapi area. The latter location is within the SCE service territory, and would become a feasible location to site generation for the Authority once PG&E expands its import capabilities from that area as discussed above. Resources located in the Pacific Northwest may also be feasible if the Authority can partner with an entity such as SMUD or another California publicly owned utility that has transmission rights from Oregon into California (e.g., the California Oregon Transmission Project) or if PG&E follows through with plans to expand its transmission system northward.

The generation projects anticipated in this resource plan is summarized in the following table.

[18] It should be noted, however, that none of the respondents to the Cities' request for information identified availability of renewable resources as one of the challenges to meeting the Program's stated objective of over 80% renewable energy by 2014.

Table 11: Community Choice Wind/Biomass Project Summary

Generation Type	Wind
Location	Greater Bay Area (e.g. Solano County)
Year On Line	2014
Capacity	150 MW
Production	450,702 MWh Per Year
Total Initial Cost	Approx. $350 Million
Average Production Cost	$85 to $105 Per MWh

Generation Type	Biomass
Location	Marin County or the California Central Valley
Year On Line	2014
Capacity	50 MW
Production	343,392 MWh Per Year
Total Initial Cost	Approx. $145 Million
Average Production Cost	Approx. $65 to $80 Per MWh

Energy Efficiency

The CPUC and State energy policy, as expressed in the Energy Action Plan and reaffirmed in D 04-12-048, is to make energy efficiency the highest priority procurement resource. As such, cost-effective energy efficiency should be first in the "loading order" of resources used to meet customers' energy service needs.[19] In order to promote the resource procurement policies articulated in the Energy Action Plan and by the CPUC, energy efficiency activities funded by ratepayers should focus on programs that serve as alternatives to more costly supply-side resource options.[20]

California electric distribution utilities (investor-owned utilities and municipal utilities) are required by law to include a separate line item on customer bills containing a surcharge, termed the Public Goods Charge (PGC), to fund Public Purpose Programs or Public Good Programs. PGC funded programs include energy efficiency, renewable energy, low-income, and research and development programs. The PGC surcharge is non-bypassable, subject to payment regardless of whether the serving distribution utility provides the energy commodity. Therefore, customers purchasing energy from a private Energy Service Provider (ESP) or a CCA must pay the PGC and may participate in PGC funded programs. Additionally, AB 117 permits CCAs to apply to administer cost-effective energy efficiency programs. All electric utilities in the state include energy efficiency programs in their resource portfolios and annual budgets for California's distribution utilities are approximately $700 million. Energy efficiency programs provide a least cost resource, are environmentally superior to supply side resources, reduce customer bills and enhance customer service.

This section addresses the treatment of energy efficiency as a component of the Authority's integrated resource plan. As described below there are opportunities for significant cost

[19] CPUC Rulemaking R.01-08-028, ATTACHMENT 3 ENERGY EFFICIENCY POLICY MANUAL FOR POST-2005 PROGRAMS, Page 2, Rule II.1.

[20] Ibid., Page 3, Rule II.3.

effective energy efficiency programs within the region, and the Authority would seek to maximize end-use customer energy efficiency by facilitating customer participation in existing utility programs as well as by forming new programs that displace the Authority's need for procuring electric supply.

This energy efficiency potential forecast serves as a means to estimate the scope and types of energy efficiency programs the Program might include within its resource portfolio within the following customer segments:

1.) Residential – Low-Income and Multi-Family
2.) Residential
3.) Commercial/Small Commercial
4.) Large Commercial/Industrial

Preliminary program planning has been prepared based on the conduct of an energy efficiency forecast that employs key assumptions and methodologies adopted by California's investor owned utilities, tailored to the County'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.

Baseline Energy Efficiency Potential Estimates

Conservative estimates indicate cost effective ("economic") energy efficiency potential exists in the Program's territory to save 181,252 MWh annually. Discounting the economic potential for customer awareness and willingness to adopt based on industry standard assumptions yields achievable energy efficiency potential of 15,100 MWh annually achievable through implementing energy efficiency programs funded at approximately $2.8 million. Table E-1 summarizes these findings below:

Table E-1 Forecast Annualized Energy Efficiency Potential and Program Budgets

	Sector Use kWh	Technical Potential kWh	Economic Potential kWh	Achievable Program Potential kWh		Achievable Program Potential kW	Program Costs
Residential	732,840,248	217,934,292	107,356,272	7,459,777	1.0%	2,774	$1,889,983
Commercial	576,235,343	78,085,059	59,356,212	7,380,674	1.3%	1,334	$874,346
Industrial	107,454,070	15,924,110	14,539,192	255,323	0.2%	39	$37,825
Composite	1,416,529,661	311,943,461	181,251,677	15,095,774	1.1%	4,147	$2,802,154

The National Action Plan for Energy Efficiency states among its key findings "consistently funded, well-designed efficiency programs are cutting annual savings for a given program year of 0.15 to 1 percent of energy sales."[21] The American Council for an Energy-Efficient Economy (ACEEE) reports for states already operating substantial energy efficiency programs energy

[21] National Action Plan for Energy Efficiency, July 2006, Section 6: Energy Efficiency Program Best Practices (pages 5-6)

efficiency goals of 1%, as a percentage of energy sales, is a reasonable level to target.[22] Forecast achievable energy efficiency equal to 1.1% of the CCA's forecast energy sales as indicated in Table E-1 above appears to be a reasonable and conservative baseline for the demand-side portion of CCA's resource plan. These savings would be in addition to the savings achieved by PG&E administered programs.

CCA Program Energy Efficiency Goals

The Program's energy efficiency goals will reflect a strong commitment to increasing energy efficiency within the County and expanding beyond the savings achieved by PG&E's programs. A realistic goal would be to increase annual savings through energy efficiency programs to 2% (combined Authority and PG&E programs) of annualized electric sales, as has been adopted by the State of New York. Achieving this goal would mean at least a doubling of energy savings relative to the status quo situation without the CCA program. Authority programs would focus on closing the gap between the vast economic potential of energy efficiency within the County and what is actually achieved.

The following table summarizes the estimated energy efficiency potential for each type of energy efficiency initiative:[23]

Table 12
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%

The retrofit of existing buildings represents 85 percent of the total forecast energy efficiency market potential. Studies show that the residential customer sector presents the largest untapped efficiency gains.

A near-term objective of the Authority is to hire Program staff that would develop specific energy efficiency programs that would seek to obtain these energy savings. The Authority may also seek requisite program funding from the CPUC to administer the energy efficiency programs. Additional details of the Authority's energy efficiency plan would be developed once the CCA Program is staffed and has begun operations.

[22] Energy Efficiency Resource Standards: Experience and Recommendations, Steve Nadel, March 2006, ACEEE Report E063 (pages 28 - 30).

[23] 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.

Demand Response

Demand response programs provide incentives to customers to reduce demand upon request by the load serving entity (i.e., the Authority), reducing the amount of generation capacity that must be maintained as infrequently used reserves. Demand response programs can be cost effective alternatives to capacity otherwise needed to comply with the resource adequacy requirements. The programs also provide rate benefits to customers who have the flexibility to reduce or shift consumption for relatively short periods of time when generation capacity is most scarce. Like energy efficiency, demand response can be a win/win proposition, providing economic benefits to the electric supplier and customer service benefits to the customer.

In its ruling on local resource adequacy, the CPUC found that dispatchable demand response resources as well as distributed generation resources should be allowed to count for local capacity requirements. The CPUC found that it may not be possible to count dispatchable demand response resources until 2008. This plan assumes that the Authority's demand response programs would partially offset its local capacity requirements beginning in 2011.

PG&E offers several demand response programs to its customers, and the Authority intends to recruit those customers that have shown a willingness to participate in utility programs into the Authority's demand response programs.[24] The goal for this resource plan is to meet 5% of the Program's total capacity requirements through dispatchable demand response programs that qualify to meet local resource adequacy requirements. This goal translates into approximately 14 MW of peak demand enrolled in the Authority's demand response programs. Achievement of this goal would displace approximately 30% of the Authority's local capacity requirement within the Greater Bay Area.

Marin Power Authority
Demand Response Goals
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Capacity Requirement (MW)	84	273	271	270	270	269	269	270	270	272
Demand Response Target	-	14	14	13	13	13	13	14	14	14
Percentage of Local Capacity Requirment	0%	30%	30%	30%	30%	30%	30%	30%	30%	30%

The Authority would adopt a demand response program that enables it to request customer demand reductions during times when capacity is in short supply or spot market energy costs are exceptionally high. The level of customer payments should be pegged to the cost of local capacity that can be avoided as a result of the customer's willingness to curtail usage upon request. This value can range from $50 to $125 per kW-Year. For planning purposes, the customer incentive is assumed to be $75 per kW-year, which is near the backstop price for local capacity resources and above the incentive levels currently offered by PG&E.[25]

[24] These programs include the Base Interruptible Program (E-BIP), the Demand Bidding Program (E-DBP), Critical Peak Pricing (E-CPP), Optional Binding Mandatory Curtailment Plan (E-OBMC), the Scheduled Load Reduction Program (E-SLRP), and the Capacity Bidding Program (E-CBP).
[25] For example, the annual customer incentive in PG&E's Capacity Bidding Program is fixed at $43.35 per kW-year in 2007 - 2008.

Appropriate limits on customer curtailments, both in terms of the length of individual curtailments and the total number of curtailment hours that can be called should be included in the Authority's demand response program design. It will also be important to establish a reasonable measurement protocol for customer performance of its curtailment obligations. Performance measurement should include establishing a customer specific baseline of usage prior to the curtailment request from which demand reductions can be measured. The Authority would likely utilize experienced third party contractors to design, implement and administer its demand response programs.

Distributed Generation

Consistent with the Authority's environmental policies and the state's Energy Action Plan, clean distributed generation is a significant component of the integrated resource plan. The Authority would work with state agencies and PG&E to promote deployment of photovoltaic (PV) systems within the Authority's jurisdiction, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public goods surcharges. PV systems are relatively expensive sources of electricity, even after considering the available buy-downs, tax incentives and benefits of net energy metering. Average production costs are in the 30 to 40 cents per kWh range as shown below. For reference, the highest priced "Tier 5" rate charged by PG&E is currently 37 cents per kWh.

Residential Photovoltaic Costs

Size (KW)	1	2
Capacity Factor	17%	17%
Production (KWh/Year)	1,489	2,978
Installed Cost	$ 10,000	$ 20,000
CEC Incentive	$ (2,600)	$ (5,200)
Federal Tax Credit	$ (2,000)	$ (2,000)
Net Cost	$ 5,400	$ 12,800
Loan Term	30	30
Rate	8.5%	8.5%
Monthly Payment	$41.52	$98.42
Average Cost ($/KWh)	$ 0.33	$ 0.40

Although distributed PV is not cost competitive with other sources of renewable supply available to the Authority (e.g., large scale wind, biomass, and geothermal), there are significant associated environmental benefits and strong customer interest in distributed PV systems. The economics of PV should improve over time as utility rates continue to increase and the costs of the systems decline with technological improvements and added manufacturing capacity. The Authority can promote distributed PV without providing direct financial assistance by being a source of unbiased consumer information and by facilitating customer purchases of PV systems through established networks of pre-qualified vendors. It may also provide direct financial incentives from revenues funded by customer rates to further support use of solar power within the Marin Communities. Finally, the Authority could provide direct incentives for PV by offering a net metering rate to customers who install PV systems so that customers are able to sell excess energy to the Authority. A proposed net metering rate is discussed in Chapter 5.

The Authority's CCA customers would contribute funds to the California Solar Initiative (CSI) through the public goods charge collected by PG&E, and would be eligible for the incentives provided under that program for installation of PV systems. The California Solar Initiative provides $2.2 billion of funding to target installation of 1,940 MW of solar systems within the investor owned utility service areas by 2017. All electric customers of PG&E, SCE, and SDG&E are eligible to apply for incentives. Approximately 44% of program funding is allocated to the PG&E service territory. Assuming solar deployment would be proportionate to funding, the program is intended to yield approximately 775 MW of solar within the PG&E service area. A minimum of 13 MW should be deployed within the jurisdictional boundaries of the Authority.

California Solar Initiative Deployment

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
IOU Territory Target (MW)	176	353	529	705	882	1,058	1,235	1,411	1,587	1,764	1,940	1,940
Total Funding ($Millions)	320	320	320	240	240	240	160	160	160	5	0	0
PG&E Funding ($Millions)	140	140	140	105	105	105	70	70	70	2	0	0
PG&E Incentives Share	44%	44%	44%	44%	44%	44%	44%	44%	44%	40%	40%	40%
PG&E Area Deployment (MW)	77	154	231	309	386	463	540	617	694	705	776	776
Marin Share of PG&E Load	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
Marin Solar Deployment (MW)	1	3	4	5	6	8	9	10	12	12	13	13

The Authority could work to ensure that customers within its jurisdiction take full advantage of the solar incentives, with the goal of exceeding the deployment targets shown above. Additional solar programs developed by the Authority could also increase use of solar in the Marin Communities.

Impact of Resource Plan on Greenhouse Gas Emissions

Reductions in greenhouse gas emissions as a result of the Program' resource plan are estimated to range from 302,330 to 534,369 tons per year by 2019, an amount approximating as much as 17% of total GHG emissions (from all sectors, including transportation) within the Marin Communities. The basis for the estimate is an increase to more than 80% (beginning in 2014) in the contribution of renewable resources to the resource mix used to serve electric customers in the Marin Communities. The baseline for comparison is the resource mix used by PG&E versus the resource mix that would be utilized by the CCA Program. This comparison is likely conservative in that it assumes PG&E would meet the 20% RPS target even though PG&E has remained at between 12% and 14% in the six years since the RPS legislation was enacted. The actual impact would be greater if PG&E misses the RPS target and less if PG&E exceeds the target, either voluntarily or by future mandate.

The precise impact on greenhouse gas emissions will depend upon the resources that would be displaced by the CCA's renewable resources. New resources will generally displace the least efficient, highest cost resources in the system as resources are dispatched on the basis of variable operating costs. The baseload nuclear, coal and hydro resources currently in the system resource mix will likely not be displaced because of their low operating costs. The low end of the estimate assumes that new renewables compete with new, efficient natural gas fired resources, while the higher estimate assumes displacement of the less efficient existing fleet of gas-fired resources. The CO_2 conversion factors for avoided air emissions used in these estimates were obtained from figures reported by the California Energy Commission (400 tons per GWh vs. new gas-fired resources, and 707 tons per GWh vs. existing resources).[26]

Marin Power Authority
Greenhouse Gas Impact
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Marin Power Authority Renewables (MWh)	145,048	857,657	855,339	855,691	985,245	988,676	992,131	996,940	1,000,579	1,005,660
Renewables Per RPS (MWh)	44,415	244,477	243,816	243,916	244,762	245,615	246,473	247,668	248,572	249,834
Program Renewable Impact (MWh)	100,633	613,180	611,523	611,774	740,483	743,061	745,658	749,273	752,007	755,826
CO2 Reduction - Low (tonnes per year)	40,253	245,272	244,609	244,710	296,193	297,225	298,263	299,709	300,803	302,330
CO2 Reduction - High (tonnes per year)	71,148	433,518	432,347	432,524	523,521	525,344	527,180	529,736	531,669	534,369

The estimated impacts do not count renewable resources that are simply transferred from the PG&E portfolio to the CCA portfolio, unless the transferred resources are replaced with new renewable resources. For example, if PG&E is unable to meet the 20% RPS standard because the Authority contracted with existing Qualifying Facilities formerly under contract to PG&E, there would be no net increase in renewable energy production. However, if PG&E contracted with new renewable resources to replace the renewable energy supply "lost" to the Authority as it surpassed the RPS, there would be a net increase in renewable energy and the greenhouse gas impact would appropriately be characterized as a benefit of the Program.

Considering the challenges faced by PG&E in achieving the 20% RPS minimum by 2010 described in its renewable resource plans filed with the CPUC, it is unlikely that PG&E would voluntarily seek to exceed this level in the foreseeable future. However, some state policy makers, including the Governor, are advocating a 33% renewable portfolio standard by 2020, and a CPUC study that found such a goal could be achieved. The greenhouse gas reduction mandate of Assembly Bill 32 may also add momentum to a 33% renewable portfolio standard, although the compliance rules will not be known for several years. Under the assumption that the statewide standard is increased to 33% and PG&E complies, the greenhouse gas benefits of the CCA program would be reduced to a range of 237,374 to 419,558 per year.

[26] California Renewable Technology Market and Benefits Assessment, November 2001.

CHAPTER 4 – Financial Plan

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 the Authority. 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 the Authority. 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 the Authority 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
- 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 the Authority'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 the Authority'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 the Authority'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% 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 the Authority's electric rates (in each of the two proposed tariffs: 100% Green and Light Green) over the CCA program implementation period.

Marin Power Authority
Comparison of Electric Rates – Authority versus distribution utility

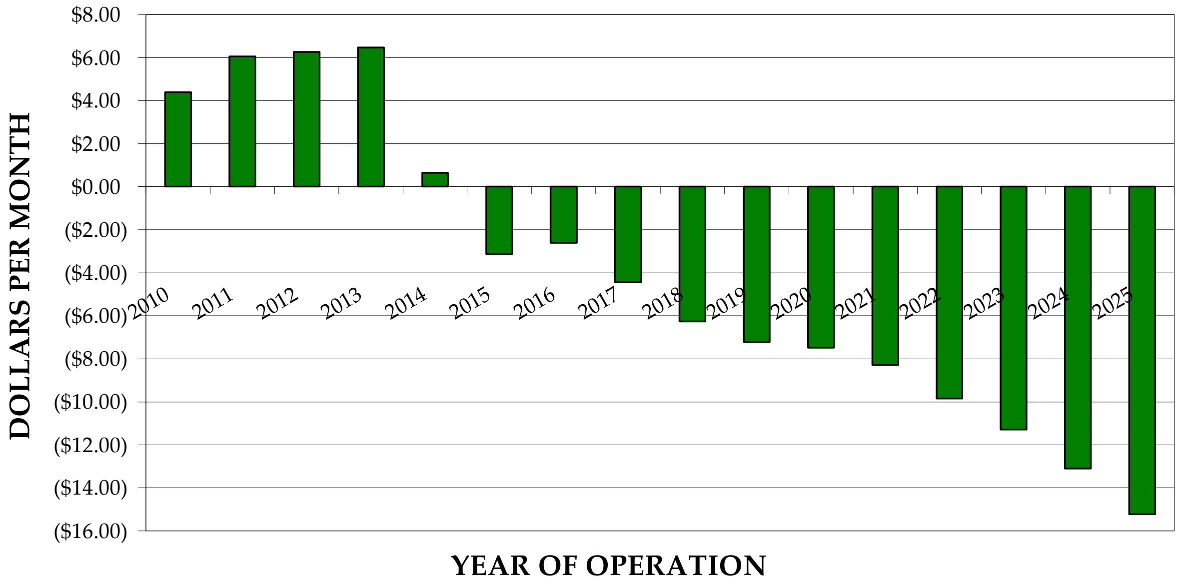
CATEGORY	2010	2011	2012	2013
Authority's Electric Rate ($/MWh)--100% Renewable	$112.34	$110.81	$114.75	$118.77
IOU Electric Rate ($/MWh)	$93.61	$92.34	$95.63	$98.97
Variance ($/MWh)	($18.72)	($18.47)	($19.13)	($19.79)
Variance in Generation Rate (%)	-20.0%	-20.0%	-20.0%	-20.0%
Impact to Monthly Residential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

CATEGORY	2010	2011	2012	2013
Authority'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, the Authority 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 the Authority at production costs, which are significantly lower than retail prices charged by energy suppliers participating in the market. Over time, the Authority'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% of the Authority'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 the Authority.[27]

[27] An "average" customer was determined based on participation levels in both the 100% 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% Green Tariff, who will pay a higher premium than that which is displayed in the chart.

**MARIN POWER AUTHORITY
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% goal), energy efficiency programs or other energy/climate initiatives within the scope of broad-based powers established for the Authority. Ultimately, the Authority 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 the Authority 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 the Authority, 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 the Authority 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 the Authority 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.

DRAFT

Marin Power Authority
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 the Marin Power Authority 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% Green Tariff during the implementation period. The incremental revenues would be used for paying the additional costs associated with the 100% renewable energy product. The premiums are projected to decline once the benefits of the Authority's renewable resources begin to be realized and as costs for fossil fuels increase.

MARIN POWER AUTHORITY
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 the Authority 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 the Authority 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 the Authority 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, the total financing requirement is estimated to be approximately $6.4 million, and subsequently grow to approximately $15.8 million following enrollment of Phase 3 customers. The Authority'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
- 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, the Authority 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 the Authority via a short-term financing, likely a letter of credit. The Authority 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 the Authority 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 the Authority 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 the Authority, the Authority 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.

Authority 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.

1. CCA Program start-up and working capital (Phases 1 and 2) – estimated at $6.4 million
2. CCA Program working capital (Phases 3 – estimated at $15.8 million
3. Renewable generation project financing – $500 million (may be financed by another entity)

---

[28] The cost of short term debt issued by the Authority is likely to be lower than the costs a supplier would charge to carry the float on the Authority's power purchases. This assumption should be confirmed once the Authority'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 the Authority and the third party supplier the amount could potentially be as low as $3.1 million because $3.3 million is for working capital related to power purchases that may ultimately be carried by the Program's electric supplier rather than the Authority. 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 the Authority'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 the Authority'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 the Authority 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 with the third-party supplier, it may be necessary for an additional $9.4 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 the Authority can put the payment "float" to the third-party energy supplier.

Renewable Resource Project Financing
This is the large project financings for the renewable resources (likely wind and biomass), currently estimated to be in the $500 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 the Authority, 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 the Authority, 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 the Authority 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, the Authority should be able to finance investments with less stringent security requirements (i.e, without the need for a Termination Fee). Additional investment by the Authority would create greater ratepayer benefits because power purchases would be displaced by production from lower cost community owned resources. The Authority 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. The Authority 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 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	$500 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 the Authority by each City.
- The CPUC's actions, if any, on the Implementation Plan submitted by the Authority.
- 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 the Authority 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% increase in market prices would increase the Authority'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 the Authority 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 the Authority.
- Customer opt-outs and turnover.

Once the Authority 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. The Authority'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 the Authority makes long term power supply commitments to renewable resources or other fixed priced electric supplies. The Authority'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 the Authority's rates or pay the Termination Fee to leave the program. The Authority'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 the Authority 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% 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% since 1980 and 5.2% 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.
- 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% 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 the Authority that much more attractive. PG&E rates may increase more than projected, and the Authority 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 the Authority 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.

Advanced Metering

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 the Authority 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 the Authority'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 the Authority 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.

The Authority's Board of Directors would approve the rate policies and procedures set forth in the Authority'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

The Authority 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 the Authority, 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% renewable energy supply option – 100% Green Tariff
- Rate competitive tariff option – Light Green Tariff
- Rate stability
- Equity among customers in each tariff
- Customer understanding
- Revenue sufficiency

Each of these objectives is described below.

Rate Competitiveness

The goal is to offer competitive rates for the electric services the Authority would provide to participating customers. For participants in the Authority's Light Green Tariff, the goal would be for the Authority's rates to be equivalent to the generation rates offered by PG&E. For participants in the Authority's 100% Green Tariff, the goal would be to offer the lowest possible customer rates with an incremental monthly cost increase of 10% 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% 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% Green Tariff, which will supply participating customers with 100% renewable energy supply at rates that reflect the program's cost for procuring necessary energy supplies. The Authority will also offer its customers a Light Green Tariff, which will maximize renewable energy supply (25% in 2010, increasing to 51% by 2014) while maintaining generation rates that are equivalent to PG&E. 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% 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 the Authority 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

The Authority 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 the Authority'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. The Authority would have more flexibility in procurement and ratesetting than PG&E to stabilize electricity costs for customers.

Equity among Customer Classes

The Authority'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 the Authority'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

The Authority's rates must collect sufficient revenue from participating customers to fully fund the Authority'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 the Authority's costs, subject to the disclosure and due process policies described later in this chapter.

100% Renewable Energy Delivery – "100% Green Tariff"

Because the Marin Communities have expressed an interest in increasing the supply of renewable energy as soon as practical, the Authority proposes to create a Green Tariff, which would allow interested customers to procure and receive 100% renewable energy supply. The 100% Green Tariff would be the Authority's default tariff, unless a customer of the program elects to participate in the Light Green Tariff option. Achieving high levels of participation in such a tariff require a well-developed marketing effort by the Authority to promote this opportunity. Due to the relatively high cost per kWh of renewable power under current market conditions, a 100% 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% renewable energy, approximately double the level of renewable energy supplied through the Authority'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% Green Tariff would be based on the current cost of renewable energy supply incurred by the Authority and may vary slightly from the guideline noted above.

By developing a 100% Green Tariff alternative for program customers, it is estimated that the Authority's renewable energy supply, expressed as a percentage of total energy supply, would increase to a level above 80% 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 the Authority 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% Green Tariff participation resulting from effective marketing efforts of the program, it appears that the program could achieve more than 80% renewable supply by 2014. Additional market research should be conducted to refine the participation assumptions.

Rate Design

The Authority'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 the Authority'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. The Authority'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). The

Authority 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 the Authority's program. The Authority may also introduce new rate options for customers, such as rates designed to encourage economic expansion or business retention within the Authority'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 the Authority as it matches the rate structures used by PG&E. PG&E's optional "rate ready" billing service, where PG&E calculates bills using the Authority'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 the Authority'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 5 cents per kWh for generation services, which is below the cost of purchasing the power from the wholesale market. If the Authority discounted all rates equally, the Authority'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. The Authority would have discretion to modify its rate design policies, and it is likely that over time the Authority'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. The Authority 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 the Authority 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, the Authority 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 the Authority. 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 the Authority'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, the Authority 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 Power Authority Estimated 2011 Program Rates

Customer Class	Program Rates – Green (Cents Per kWh)	Program Rates – Light Green (Cents Per kWh)	PG&E Generation Rate (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% per year.			

[31] The Authority 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.

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. The Authority's rates shown include all costs expected to be incurred by the Authority related to the aggregation program, including power supply costs, operations and administration costs, reserves, and billing and metering fees charged by PG&E to the Authority. For the sake of comparison, the Authority's rates are shown inclusive of the cost responsibility surcharges that the Authority'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.

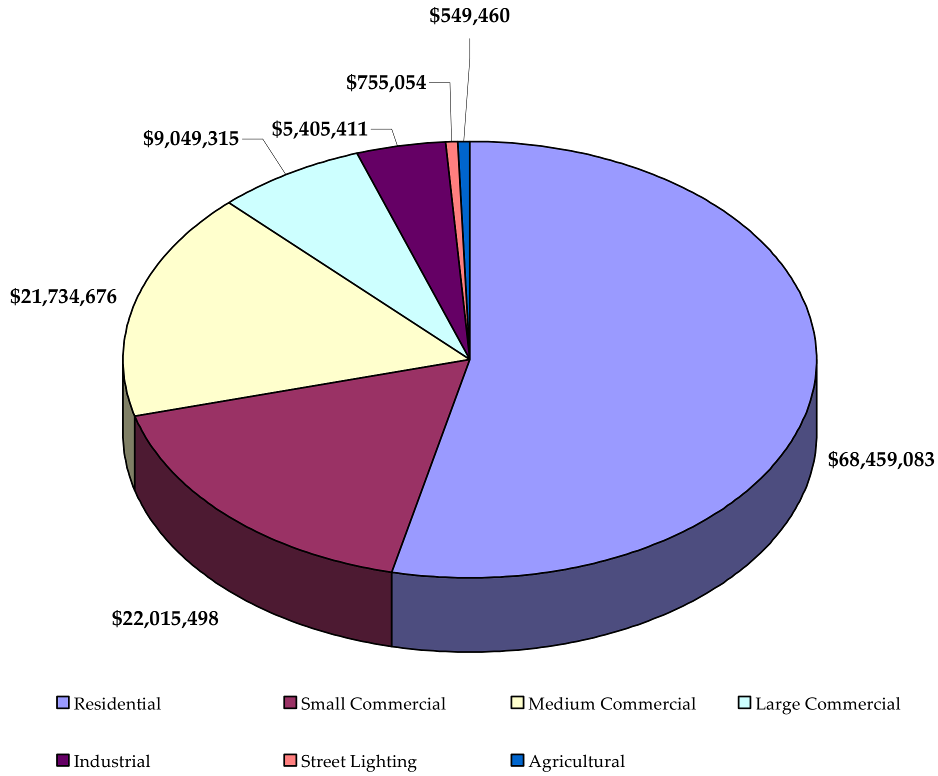
The Authority would initially adopt customer noticing requirements similar to those the CPUC requires of PG&E and SCE. These notice requirements are described as follows:

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 the Authority 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, the Authority 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 the Authority 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 the Authority are shown in the following chart:

Figure 4: 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 the Authority'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. The Authority 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, the Authority 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 the Authority'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 the Authority.

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. The Authority'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 the Authority 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 the Authority 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 the Authority'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 the Authority's Governing Board as part of the annual ratemaking process.

The long-term financial projections contained in Appendix A indicate that the Authority may be able to offer rates that are generally below those charged by PG&E and that the Authority's supply portfolio is projected to be competitive in the marketplace because of the financing advantages that the Authority enjoys. Under those conditions, most customers would not be expected to terminate their service with the Authority to return to the utility. Furthermore, if customers do terminate service, the Authority 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, the Authority's ability to assess a Cost Recovery Charge, if necessary, is an important condition for obtaining financing for the Authority's power supply. The low cost financing will, in turn, enable the Authority 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 the Authority 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 the Authority's Board of Directors, subject to the Authority'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
The Authority would establish policies covering confidentiality of customer data. The Authority'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 the Authority's discretion or as required by law or regulation.

Responsibility for Payment
Customers would be obligated to pay the Authority charges for service provided through the date of transfer including any applicable Termination Fees. Pursuant to current CPUC regulations, the Authority would not be able to direct that electricity service be shut off for failure to pay the Authority'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 the Authority's Board based on experience or regulatory changes that would provide the Authority 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 the Authority'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 the Authority'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.

CHAPTER 6 – Marketing Plan

This Chapter presents the key elements of a proposed marketing plan for Marin's CCA Program, including the promotion of its 100% 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 Power Authority 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 the Authority.

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 the Authority'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% of the Marin Communities' electric load; Industrial customers account for 5% of total load). To ensure that these accounts remain customers of the Authority, it will be important to identify ways in which the Authority 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 the Authority. For other large customers, additional incentives may be necessary to encourage a new business relationship with the Authority. In these instances, it will be incumbent upon the Authority 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, the Authority 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 the Marin Power Authority. While the specific graphics and/or verbiage displayed on this logo would need to be developed by the Authority, such a logo would likely display the following general message: "Proud Renewable Energy Partner of the Marin Power Authority." A logo or seal of this sort, used under a no-cost licensing agreement with the Authority, 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, the Marin Power Authority 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 the Authority, in addition to name recognition of the Authority'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, the Authority could develop a second logo or seal for large energy customers who choose to participate in its 100% 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 the Authority's Green Power Tariff. Due to the increased cost incurred by participants in the 100% Green Tariff, the Authority may choose to further distinguish this logo or seal by clearly displaying verbiage such as, "Powered by 100% Green Energy – Delivered from the Marin Power Authority." Many businesses may find that the rate increase incurred as a result of participating in the Authority's 100% 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, the Authority may choose to provide these Business Partners with additional and prominent, recognition for their participation in the 100% Green Tariff by displaying corporate/business logos on the "Home Page" of the Authority'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 the Authority 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.

CHAPTER 7 - Procurement Process

Introduction

This Chapter describes the Authority's initial procurement policies and the key third party service agreements by which the Authority would obtain operational services for the CCA Program. The Authority'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

The Authority would enter into agreements for a variety of services needed to support program development, operation and management. It is anticipated the Authority 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.

The Authority 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 the Authority'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 Power Authority has 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 the Authority 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 the Authority and will be required to meet the renewable portfolio requirements specified by the Authority 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% 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% in 2010, increasing to 70% 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
- 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 the Authority greater flexibility to change energy suppliers, if desired, without facing an expensive data migration issue.

It is anticipated that the Authority 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.

Chapter 8 - Program Termination

Introduction

This Chapter describes the process to be followed in the case of Program termination. In the unexpected event that the Authority 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 Authority

The Authority 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 the Authority/program, each governing body would be required to adopt a termination ordinance or resolution and provide adequate notice to the Authority (such as 90 days). Following such notice, the Authority 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 the Authority 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.

The Authority 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 the Authority 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 the Authority, however, the non-municipal accounts (such as residential, commercial and industrial accounts) would remain customers of the Authority and would continue to receive electricity procured by the Authority on their behalf. Because these non-municipal accounts would remain customers of the Authority, 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 Authority 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 the Authority; 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

DRAFT

Appendix A – Pro Forma 2014-2025

MARIN POWER AUTHORITY
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% 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% (all other residential programs)
Commercial: 80% (all other nonresidential programs)
Industrial: 80% (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:

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

where:

[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% 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% 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:

---

[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% . . .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 % 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."

[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.

Section 3 – Sources

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

ATTACHMENT A – SECTOR MEASURE LISTS

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

ATTACHMENT A – SECTOR MEASURE LISTS - *continued* –

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

ATTACHMENT A – SECTOR MEASURE LISTS - *continued* –

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 Avoided Cost Rate by TOU	Residential 2005 Energy Use	Residential Avoided Cost TOU Amount	Commercial Avoided Cost Rate by TOU	Commercial 2005 Energy Use	Commercial Avoided Cost TOU Amount	Industrial Avoided Cost Rate by TOU	Industrial 2005 Energy Use	Industrial Avoided Cost TOU Amount	Composite 2005 Energy Use	Composite Avoided Cost TOU Amount	Composite 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	Year	Winter On-Peak $/kWh Gen	T&D	Env. Ext.	Total	Winter Off-Peak $/kWh Gen	T&D	Env. Ext.	Total
1	0.11			0.11	0.08			0.08	2009	0.08			0.08	0.06			0.06
2	0.12			0.12	0.08			0.08	2010	0.09			0.09	0.06			0.06
3	0.12			0.12	0.08			0.08	2011	0.09			0.09	0.06			0.06
4	0.12			0.12	0.08			0.08	2012	0.09			0.09	0.06			0.06
5	0.12			0.12	0.08			0.08	2013	0.09			0.09	0.06			0.06
6	0.13			0.13	0.09			0.09	2014	0.10			0.10	0.06			0.06
7	0.13			0.13	0.09			0.09	2015	0.10			0.10	0.07			0.07
8	0.13			0.13	0.09			0.09	2016	0.10			0.10	0.07			0.07
9	0.14			0.14	0.09			0.09	2017	0.10			0.10	0.07			0.07
10	0.14			0.14	0.09			0.09	2018	0.11			0.11	0.07			0.07
11	0.14			0.14	0.10			0.10	2019	0.11			0.11	0.07			0.07
12	0.15			0.15	0.10			0.10	2020	0.11			0.11	0.07			0.07
13	0.15			0.15	0.10			0.10	2021	0.11			0.11	0.08			0.08
14	0.16			0.16	0.10			0.10	2022	0.12			0.12	0.08			0.08
15	0.16			0.16	0.11			0.11	2023	0.12			0.12	0.08			0.08
16	0.16			0.16	0.11			0.11	2024	0.12			0.12	0.08			0.08
17	0.17			0.17	0.11			0.11	2025	0.13			0.13	0.08			0.08
18	0.17			0.17	0.12			0.12	2026	0.13			0.13	0.09			0.09
19	0.18			0.18	0.12			0.12	2027	0.13			0.13	0.09			0.09
20	0.18			0.18	0.12			0.12	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

Authority – The Marin Power Authority, a Joint Powers Agency with membership consisting of Marin County and the eleven cities within the geographic boundaries of the County

CAISO – California Independent System Operator

CALMAC – California Measurement Advisory Council

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
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 – Renewable 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