MARIN ENERGY AUTHORITY

COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PLAN AND STATEMENT OF INTENT

marin energy authority

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CHAPTER 1 – Introduction

The Marin Energy Authority ("MEA" or "Authority") is a public agency comprised of eight municipalities[1], located within the geographic boundaries of Marin County, formed for the purposes of implementing a community choice aggregation ("CCA") program and other energy-related programs targeting significant greenhouse gas emissions ("GHG") reductions. Member Agencies of the Authority include the cities of Belvedere, Fairfax, Mill Valley, San Anselmo, San Rafael, Sausalito and Tiburon and the County of Marin ("Members" or "Member Agencies"). This Implementation Plan describes the Authority's plans to implement a voluntary CCA Program for electric customers within the jurisdictional boundaries of its Member Agencies that currently take bundled electric service from Pacific Gas and Electric Company ("PG&E"). The CCA Program, which has been named Marin Clean Energy ("MCE" or "Program"), will give electricity customers the opportunity to join together to procure electricity from competitive suppliers, with such electricity being delivered over PG&E's transmission and distribution system. The planned start date for the Program is June 1, 2010 (subject to the final review and approval of the Authority's Board). All current PG&E customers within the Authority's service area will receive information describing the Program and will have multiple opportunities to express their desire to remain full requirement customers of PG&E, in which case they will not be enrolled in the Program. Thus, participation in the CCA Program is completely voluntary; however, customers, as provided by law, will be automatically enrolled unless they affirmatively elect to opt-out of the CCA Program.

Implementation of MCE will enable customers within MEA's service area to take advantage of the opportunities granted by Assembly Bill 117 ("AB 117"), the Community Choice Aggregation Law. MEA's primary objective in implementing this Program is to increase utilization of renewable energy supplies and promote significant GHG emissions reductions by offering customers at least two new energy supply options: 1) 25 percent renewable content, which will be the default service option for participating customers; or 2) 100 percent renewable content. The prospective benefits to consumers include a substantial increase in renewable energy supply, stable and competitive electric rates, public participation in determining which technologies are utilized to meet local electricity needs, and local/regional economic benefits.

Because providing retail electric service can be a complex undertaking and the Authority has no operational experience in procuring electricity for retail customers, the Authority will receive assistance from experienced energy suppliers and contractors in providing energy services to Program customers during the early years of program operations. Following a competitive solicitation process and subsequent contract negotiations, three qualified firms were selected for consideration as the Authority's initial energy services provider and scheduling coordinator. Information regarding the three shortlisted companies is contained in Chapter 10. The final supplier selection is scheduled to be made by the MEA Board in February 2010.

[1] MEA's member municipalities include Belvedere, Fairfax, Mill Valley, San Anselmo, San Rafael, Sausalito, Tiburon and Marin County.

MEA's Implementation Plan reflects a collaborative effort among the Authority, its Members, and the private sector to bring the benefits of competition and choice to Member residents and businesses. By exercising its legal right to form a CCA Program, the Authority will enable its Members' constituents to access the competitive market for energy services and obtain access to increased renewable energy supplies and resultant reductions in GHG emissions. Absent action by the Authority or its individual Members, most customers would have no ability to choose an electric supplier and would remain captive customers of their incumbent utility.

The California Public Utilities Code provides the relevant legal authority for the Authority to become a Community Choice Aggregator and invests the California Public Utilities Commission ("CPUC" or "Commission") with the responsibility for establishing the cost recovery mechanism that must be in place before customers can begin receiving electrical service through the Authority's CCA Program. The CPUC also has responsibility for registering the Authority as a Community Choice Aggregator and ensuring compliance with basic consumer protection rules. The Public Utilities Code requires that an Implementation Plan be adopted at a duly noticed public hearing and that it be filed with the Commission in order for the Commission to determine the cost recovery mechanism to be paid by customers of the Program in order to prevent shifting of costs. Each of these milestones has been accomplished, and the Authority now submits this Implementation Plan to the CPUC. On December 3, 2009, the Authority, at a duly noticed public hearing, considered and adopted this Implementation Plan, through MEA Resolution No. 2009-10 (a copy of which is included as part of Appendix A). The Commission has established the methodology that will be used to determine the cost recovery mechanism, and PG&E now has approved tariffs for imposition of the cost recovery mechanism. Finally, each of the Authority's Members has adopted an ordinance to implement a CCA program through its participation in the Authority (copies of individual ordinances are included as Appendix A). Following the CPUC's certification of its receipt of this Implementation Plan and resolution of any outstanding issues, the Authority will take the final steps needed to register as a CCA prior to initiating the customer notification and enrollment process.

Organization of this Implementation Plan

The content of this Implementation Plan complies with the statutory requirements of AB 117. As required by PU Code Section 366.2(c)(3), this Implementation Plan details the process and consequences of aggregation and provides the Authority's statement of intent for implementing a CCA program that includes all of the following:

- Universal access;
- Reliability;
- Equitable treatment of all customer classes; and
- Any requirements established by state law or by the CPUC concerning aggregated service.

The remainder of this Implementation Plan is organized as follows:

Chapter 2: Aggregation Process
Chapter 3: Organizational Structure
Chapter 4: Startup Plan and Funding
Chapter 5: Program Phase-In
Chapter 6: Load Forecast and Resource Plan
Chapter 7: Financial Plan
Chapter 8: Ratesetting
Chapter 9: Customer Rights and Responsibilities
Chapter 10: Procurement Process
Chapter 11: Contingency Plan for Program Termination
Appendix A: Authority Resolution 2009-10 and Authority Member Ordinances
Appendix B: Joint Powers Agreement

The requirements of AB 117 are cross-referenced to Chapters of this Implementation Plan in the following table.

AB 117 Cross References

AB 117 REQUIREMENT	**IMPLEMENTATION PLAN CHAPTER**
Process and consequences of aggregation	Chapter 2: Aggregation Process
Organizational structure of the program, its operations and funding	Chapter 3: Organizational Structure Chapter 4: Startup Plan and Funding Chapter 7: Financial Plan
Ratesetting and other costs to participants	Chapter 8: Ratesetting Chapter 9: Customer Rights and Responsibilities
Disclosure and due process in setting rates and allocating costs among participants	Chapter 8: Ratesetting
Methods for entering and terminating agreements with other entities	Chapter 10: Procurement Process
Participant rights and responsibilities	Chapter 9: Customer Rights and Responsibilities
Termination of the program	Chapter 11: Contingency Plan for Program Termination
Description of third parties that will be supplying electricity under the program, including information about financial, technical and operational capabilities	Chapter 10: Procurement Process
Statement of Intent	Chapter 1: Introduction

Chapter 2 – Aggregation Process

Introduction

This chapter describes the background leading to the development of this Implementation Plan and describes the process and consequences of aggregation, consistent with the requirements of AB 117.

Beginning in 2004, the County of Marin ("County"), each of the municipalities within its geographic boundaries[2] and the two water districts within the County began investigating formation of a CCA Program, pursuant to California state law, with the following primary objectives: 1) promoting use of renewable energy resources; 2) reducing GHG emissions in the region; 3) promoting energy efficiency; and 4) creating local economic benefits. A feasibility study for a CCA Program serving the region was completed in March 2005, and an independent review of the feasibility study and a supplemental risk analysis were completed in August 2005 and May 2006, respectively.

After nearly a year of collaborative work by representatives of the participating municipalities, independent consultants, local experts and stakeholders, the participating municipalities released a business plan in April 2008, which described the planned organization, governance and operation of the CCA Program. Consistent with the business plan's described organizational structure, the MEA was formed in December 2008 to implement the CCA Program and other energy-related programs targeting significant GHG reductions. As previously noted, Member Agencies of the Authority include the cities of Belvedere, Fairfax, Mill Valley, San Anselmo, San Rafael, Sausalito and Tiburon and the County of Marin.

The proposed CCA Program, Marin Clean Energy, represents a culmination of planning efforts that are responsive to the expressed needs and priorities of the citizenry and business community within Marin. Through MCE, the Marin Energy Authority plans to expand the energy choices available to eligible customers, including the creation of a 100% renewable energy product. In effect, MCE would provide Marin residents and businesses with three electric service options, which include: 1) 100% renewable energy service; 2) 25% (minimum) renewable energy service; or 3) bundled energy service from the incumbent utility. It is MEA's long-term goal to supply its customers entirely with clean, renewable energy, subject to economic and operational constraints.

Each of the Member Agencies has adopted an ordinance to implement a CCA program through its participation in the Authority. The final Implementation Plan was adopted at a duly noticed public hearing of the Authority on December 3, 2009.

Process of Aggregation

Before customers are enrolled in the Program, customers will receive two written notices in the mail, from the Authority, that will provide information needed to understand the Program's

[2] The municipalities participating in CCA investigation and analysis included Belvedere, Corte Madera, Fairfax, Larkspur, Mill Valley, Novato, San Anselmo, San Rafael, Sausalito, Tiburon and Ross.

terms and conditions of service and explain how customers can opt-out of the Program, if desired. All customers that do not follow the opt-out process specified in the customer notices will be automatically enrolled, and service will begin at their next regularly scheduled meter read date at least thirty days following the date of automatic enrollment, subject to the service phase-in plan described in Chapter 5. The initial opt-out notices will be provided to the first phase of customers in March 2010. Initial opt-out notices will be provided to subsequent customer phases consistent with statutory requirements and based on schedule(s) determined by the Authority's Board of Directors – notices will be sent to customers in subsequent phases beginning 90 to 105 days prior to commencement of service or twice within 60 days of automatic enrollment. Follow-up opt-out notices will be provided within the first two months of service for each customer phase.

Customers enrolled in the Program will continue to have their electric meters read and be billed for electric service by the distribution utility (PG&E). The electric bill for Program customers will show separate charges for generation procured by the Program and all other charges related to delivery of the electricity and other utility charges that will continue to be assessed by PG&E.

After service cutover, customers will be given two additional opportunities to opt-out of the Program and return to the distribution utility (PG&E) following receipt of their first and second bills. Customers that opt-out between the initial cutover date and the close of the post enrollment opt-out period will be responsible for program charges for the time they were served by the Authority but will not otherwise be subject to any penalty for leaving the program. Customers that have not opted-out within thirty days of the fourth opt-out notice will be deemed to have elected to become a participant in the Program and to have agreed to the Program's terms and conditions, including those pertaining to requests for termination of service, as further described in Chapter 8.

Consequences of Aggregation

Rate Impacts

Program customers will see no immediate changes in electric service other than the price and composition of their electric bills. Customers will pay the generation charges set by the Authority and no longer pay the costs of PG&E generation. Customers enrolled in the Program will be subject to the Program's terms and conditions, including responsibility for payment of all Program charges as described in Chapter 9.

The Authority's rate setting policies described in Chapter 7 establish a goal of providing rates that are initially competitive (at or below) with the projected generation rates offered by the incumbent distribution utility (PG&E). The Authority will establish rates sufficient to recover all costs related to operation of the Program, and actual rates will be adopted by the Authority's governing board.

Initial Program rates will be established following approval of the Authority's inaugural program budget, reflecting final costs from the Program's energy supplier(s). The Authority's rate policies and procedures are detailed in Chapter 7. Information regarding final Program rates will be disclosed along with other terms and conditions of service in the pre-enrollment opt-out notices sent to potential customers.

Once the Program gives definitive notice to PG&E that it will commence service, Program customers are not expected to be responsible in any way for costs associated with the utilities' future electricity procurement contracts or power plant investments. Certain pre-existing generation costs will continue to be charged by PG&E to CCA customers through a separate rate component, called the Cost Responsibility Surcharge or CRS. This charge is shown in PG&E's tariff, which can be accessed from the utility's website, and the costs are already included in rates currently paid.

Renewable Energy Impacts

A second consequence of the Program will be an increase in the proportion of energy generated and supplied by renewable resources. The resource plan includes procurement of renewable energy sufficient to meet a minimum of 25 percent of the Program's electricity needs. Customers of the Authority may voluntarily participate in a 100 percent renewable supply option. To the extent that customers choose to participate in this voluntary program, the renewable content of MEA's power supply would increase. Initially, this renewable energy will be met contractually, but may be complemented, at an indeterminate point in the future, by the development of new renewable generation resources by or for the Authority subject to then-current considerations (such as development costs, regulatory requirements and other concerns).

Energy Efficiency Impacts

A third consequence of the Program will be an increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by the distribution utility are not expected to change as a result of the Authority forming the Program. CCA customers will continue to pay the Public Goods Charge ("PGC") to the distribution utility which fund energy efficiency programs for all customers, regardless of generation supplier. The energy efficiency investments ultimately planned for the Program, as described in Chapter 5, will be in addition to the level of investment that would continue in the absence of the Program. Thus, the Program has the potential for increased energy savings and a further reduction in emissions due to expanded energy efficiency programs. As planned, MEA will apply for administration of requisite PGC program funding from the CPUC to independently administer energy efficiency programs within its jurisdiction.

CHAPTER 3 – Organizational Structure

This section provides an overview of the organizational structure of the Authority and its proposed implementation of the CCA program. Specifically, the key agreements, governance, management, and organizational functions of the Authority are outlined and discussed below.

Organizational Overview

The CCA program would be governed by MEA's Board of Directors ("Board"), appointed by the Members. MEA is a joint powers agency created in December 2008 and formed under California law. The County of Marin and eight municipalities within the geographic boundaries of the County that have elected to offer the Program to their constituents have become Members of MEA. The Marin Energy Authority is the CCA entity that will register with the CPUC, and it is responsible for implementing and managing the program pursuant to the Authority's Joint Powers Agreement ("JPA Agreement" or "Agreement"). The Program will be operated under the direction of a General Manager appointed by the Board. The General Manager will report to the Board comprised of one representative from each participating Member of MEA. Those who are 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 and Town Councils (one representative will be selected from each of the eight City and Town Councils) of the Members.

The Board's primary duties will be to establish program policies, set rates and provide policy direction to the General Manager, 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 for the organization. The Board may also adjust staffing levels and compensation over time in response to varying workloads, specific programs and/or general responsibilities of MCE.

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

The Board has established a Chairman and other officers from among its membership and has established an Executive Committee and Technical Committee and may establish other committees and sub-committees as needed to address issues that require greater expertise in particular areas (e.g., finance or contracts). MCE may also establish an "Energy Commission" formed of Board-selected designees. The Energy Commission would have responsibility for evaluating various issues that may affect MCE and its customers, including rate setting, and would provide analytical support and recommendations to the Board in these regards.

The General Manager will have responsibilities over the functional areas of Finance, Regulatory Affairs, and Operations. In performing his or her obligations to the Authority, the General Manager will utilize 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, will be performed initially by experienced third-party contractors.

Governance

MEA has a Board of Directors consisting of one representative from each of the Members. The Board meets at regular intervals to provide the overall management and guidance for MCE. All Board meetings will be public and held in accordance with the Ralph M. Brown Act.

Decisions by MEA are under voting procedures defined in the JPA Agreement, attached hereto as Appendix B. All votes on a particular matter are subject to the two-tiered approval process described in the JPA Agreement.

Officers

MEA has 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, MEA will have a Board Clerk and Auditor; neither of which will be members of the Board of Directors. The JPA Agreement provides further detail with respect to each of these positions.

Committees

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

Addition/Termination of Participation

The JPA Agreement provides for the addition of new participants subject to the affirmative vote of MEA's Board of Directors pursuant to the voting structure described in the Agreement. The Board will determine the specific terms and conditions under which a new Member can be admitted.

A JPA Member can withdraw itself from the JPA subject to the specific terms and conditions contained in the JPA Agreement.

Agreements Overview
There are two principal agreements that govern MEA and the initial operation of 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 created MEA and delineates a broad set of powers related to the study, promotion, development, and conduct of electricity-related projects and programs. The JPA Agreement describes the Authority as having broad powers, but a very limited role without implementing agreements ("program agreements") to carry out specific programs. This structure is intended to provide flexibility for MEA to undertake other programs in the future that may be unrelated to CCA on behalf of all or a subset of MEA's Members. 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 affected Member. 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 the Board.

The first program agreement or PA-1, discussed in greater detail below, would provide for electric generation service to customers of the CCA Program. At MEA's Members' discretion, future program agreements could provide for other energy related programs.

Program Agreement No. 1
PA-1 consists of three components: 1) the Edison Electric Institute ("EEI") Master Power Purchase & Sale Agreement ("Master EEI Agreement"), which is a standard industry contract used by public and private utilities across the United States; 2) the EEI Master Power Purchase & Sale Agreement Cover Sheet, which provides additional detail related to MEA's specific transaction, identifying exceptions, clarifications and areas of applicability that modify the standard terms and conditions of the Master EEI Agreement; and 3) the Confirmation, which is referenced in the Master EEI Agreement and defines the commercial terms of MEA's transaction. PA-1 is the agreement under which MEA will procure all necessary electric supply services for MCE customers. As drafted, PA-1 specifies a five year delivery period, commencing on June 1, 2010 and ending on May 31, 2015. PA-1 specifies a full requirements energy product, including all electric energy, renewable energy, capacity, ancillary services and scheduling coordination services. Based on contract negotiations, PA-1 will specify fixed annual prices for each year of the delivery period and will insulate municipal funds/budgets of the Member Agencies before, during and after the delivery period. It is anticipated that PA-1 will be executed by MEA and its energy supplier(s) on or around February 4, 2010.

Agency Operations
The Authority will conduct program operations through its own internal staff and through contracting for services with third parties. MEA will have its own General Counsel to manage

its legal affairs. MEA's General Manager will have responsibility for day-to-day operations of the Program. To assist the General Manager, MEA will hire a full-time Administrative Assistant, who will also serve as Board Clerk. Other staff positions that may be added as necessary include positions in finance, customer services, energy efficiency and other local energy programs, and operations.

Major MCE functions that will be performed and managed by the General Manager are summarized below.

Resource Planning

MEA is charged with developing both short (one and two-year) and long-term resource plans for the program. The General Manager will 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. MEA'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. Plans will 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.

MEA will initially contract with an experienced and financially sound third party to perform most of the portfolio operation requirements for the CCA Program. These requirements include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading. PA-1 is the contractual instrument that has been developed for this purpose; additional detail related to PA-1 is provided in the preceding discussion.

MEA will approve and adopt a set of _Program Controls_ that will serve as the risk management tools for the General Manager 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 operational risks, pursuant to the terms and conditions of PA-1.

Operations & Local Energy Programs

A key focus of the CCA Program will be the development and implementation of local energy programs for its Members, including energy efficiency programs, distributed generation programs and other energy programs responsive to Member interests. The General Manager will be responsible for further development of these Programs. To assist the General Manager in this regard, MEA will initially hire a full-time Director of Operations & Local Energy Programs. Over time, MEA may hire up to three full-time Project Coordinators to administer these programs, 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, MEA will continue enhancing its local energy programs to achieve MEA's desired goals and objectives.

MEA will administer energy efficiency, demand response and distributed (solar) generation programs that can be used as cost-effective alternatives to procurement of supply-side resources. MEA will 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, including 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 MCE customers.

Rate Setting

The Board of Directors has the ultimate responsibility for setting the electric generation rates for the Program's customers. The General Manager in cooperation with the Assistant General Manager of Finance and appropriate advisors, consultants and committees of the Board will be responsible for developing proposed rates and options for the Board to consider before finalization. The final approved rates must, at a minimum, meet the annual revenue requirement developed by the General Manager, 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 General Manager in cooperation with the Assistant General Manager of Finance will be responsible for managing the financial affairs of MCE, 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 General Manager 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.

The retail settlements (customer billing) would be contracted out to an organization with the necessary infrastructure and capability to handle approximately 71,000 accounts during full Program phase-in, which is scheduled to occur by January 2012. 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 General Manager in cooperation with the Director of Customer Relations & Marketing will be responsible for the Customer Services function and will use staff and/or contractors in support of these activities as appropriate.

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 MCE, tracking of customer payments and accounts receivable, issuance of late payment and/or service termination notices, and administration of customer deposits in accordance with MCE credit policies.

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

MEA will conduct 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 MEA, its Members and MCE customers. MEA 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 Program's Director of Regulatory Affairs and/or qualified contractors.

MEA will retain legal services, as necessary, to administer MEA, review contracts, and provide overall legal support to the activities of MEA.

Roles and Functions

The Board will perform the functions inherent in its policy-making, management and planning roles. MEA is the public face of the Program and will have a direct role in marketing, communications and customer service. Other highly specialized functions, such as energy supply and account management, will be contracted out to third parties with sufficient experience, technical and financial capabilities. The functions that will initially be performed by MEA's Board of Directors, the General Manager and third parties are specified below:

Organization	***Roles/Functions/Activities***
MEA Board of Directors	*Executive/Policy/Legal*
General Manager	*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/DG 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*

Staffing

Staffing requirements for the above MCE 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 General Manager will have discretion whether to internally staff these required functions or to contract for these services.

The following table shows the staffing plan for Marin Clean Energy at initial full-scale operational levels, following full phase-in. Customer service for the mass market residential and small commercial customers will be provided by the Program's third party customer account services provider.

Staffing Plan for Marin Clean Energy
Community Choice Aggregation Program

Position	**Staff (Full Time Equivalents)**
Management	
General Manager	1.0
Policy Analyst	1.0
Administrative Assistant	1.0
Finance and Rates	
Assistant General Manager of Finance	1.0
Rates Analyst	1.0
Accounting/Billing Analyst	1.0
Sales and Marketing	
Director of Customer Relations & Marketing	1.0
Account Representative	4.0
Communications Specialist	1.0
Administrative Assistant	1.0
Operations & Local Energy Programs	
Director of Operations & Local Energy Programs	1.0
Project Coordinators	3.0
Regulatory	
Director of Regulatory Affairs	1.0
Regulatory Analyst	1.0
Information Technology	
IT Specialist	1.0
Human Resources	
HR Specialist	0.5
Total Staffing	**20.5**

Longer-term staffing needs will include additional energy efficiency and distributed generation activities and potentially the creation of an internal organization to perform the portfolio operations and account services functions that will originally be contracted out.

This Chapter presents the Authority's plans for the start-up period, including the necessary staffing and capital outlays, which will commence once the CPUC certifies its receipt of this Implementation Plan. As described in the previous Chapter, the Authority will utilize a mix of staff and contractors in its CCA Program implementation. The following table illustrates the expectations for start-up, near-term (two to five years), and long-term anticipated staffing roles.

Expectations for Staffing Roles

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

Staffing Requirements

Staff will 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 startup period, minimal staffing requirements would include a General Manager, an Assistant to the General Manager, an Assistant General Manager of Finance, a Director of Customer Relations & Marketing, a Director of Operations & Local Energy Programs and a Project Coordinator (6 full time equivalent positions). MEA will hire the General Manager, Assistant to the General Manager, Assistant General Manager of Finance, a Director of Customer Relations & Marketing, a Director of Operations & Local Energy Programs and Project Coordinator as its direct staff but may choose to fill all other necessary positions with staff and/or contractors at the discretion of the General Manager and MEA's Board. Following these initial staffing efforts, additional staff and/or contractors will 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 (and any subsequent phases, as necessary) customers are enrolled.

Actual staff will be dependent upon several factors, including the ability to recruit and hire qualified staff and personnel policies ultimately established by the General Manager and the Board of Directors.

Capital Requirements

The Start-up of the CCA Program will require capital for three major functions: (1) staffing and contractor costs; (2) program initiation; and (3) working capital. Each of these and the anticipated requirement is discussed below. The Finance Plan in Chapter 7 provides a detailed overview of the capital requirements.

Staffing costs for calendar year 2010 are estimated to be approximately $940,000. Actual costs may vary depending on the ability of MEA to recruit qualified staff to fill the roles described above. Contractor costs for the same time period are estimated to be approximately $1.6 million. These costs include: public relations, marketing/advertising, consulting, legal, and data management services.

Program initiation costs include administrative and general expenses of MEA as well as the distribution utility fees for initiating the CCA Program. Administrative and general expenses are estimated to be approximately $165,000 and the distribution utility fees, which include CCA Bond requirements and a service deposit, are estimated to be approximately $265,000.

Therefore, the total staffing, contractor and program initiation costs are expected to be approximately $2.9 million in 2010. These are costs that ultimately will be collected through CCA Program rates; however, some of these costs will be incurred prior to the Authority selling its first kWh of electricity. In addition, as discussed in Chapter 7 (Financial Plan), it is anticipated that additional working capital will be required to purchase electricity for Program customers prior to revenue being collected from those customers.

The amount of financing required to support the CCA Program through the start-up and initial phase-in period, including working capital and net of revenues received from energy sales during Phase 1, is estimated to be $2.0 million. The actual amount of financing required will be primarily dependent upon power purchase requirements. Short-term financing instruments, such as a letter of credit or commercial paper will be used to cover these start-up costs and working capital requirements not otherwise covered by other capital infusions.

Startup Activities and Costs

The initial startup funding estimate of $2.0 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 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 are shown below for program staff, associated administrative and general expenses, 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 during calendar year 2010.

Estimated Start-up Costs

Start-up Costs	Start-Up					Phase 1 Operations						
Staffing	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
FTEs		2	4	7	7	6	6	6	6	6	6	6
Cost		$ 40,583	$ 60,833	$ 104,583	$ 104,583	$ 90,000	$ 90,000	$ 90,000	$ 90,000	$ 90,000	$ 90,000	$ 90,000
Administrative & General												
Cost		$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Contractor Costs												
Marketing/Communications		$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Consulting		$ -	$ 145,000	$ 50,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000
Legal		$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000
Data Management		$ -	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Subtotal Contractor Costs		$ 80,000	$ 235,000	$ 140,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000
IOU Fees (Including Billing)												
Cost		$ -	$ 185,000	$ 5,000	$ 5,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Grand Total		$ 135,583	$ 495,833	$ 264,583	$ 274,583	$ 265,000	$ 265,000	$ 265,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000

Estimated Staffing Costs

Staffing budgets include direct salaries and benefits loading. MEA anticipates funding six full-time positions during initial phase-in, including a General Manager, an Assistant to the General Manager, an Assistant General Manager of Finance, a Director of Customer Relations & Marketing, a Director of Operations & Local Energy Programs and a Project Coordinator.

Estimated Administrative & General Expenses

Administrative and general expenses needed to support the organization include computers and peripheral equipment, office furnishings, office space and utilities. Office space and utilities are ongoing monthly expenses that will begin to accrue before revenues from Program operations commence and are therefore assumed to be financed along with other startup costs.

Utility Implementation and Transaction Charges

The estimated costs payable to the distribution utilities for services related to the CCA Program start-up period include costs associated with initiating service with the Authority, providing data, processing of customer opt-out notices, customer enrollment, post enrollment opt out processing, and billing fees. Most of the distribution utility fees are explicitly stated in the relevant CCA tariffs.

Estimates of Third-Party Contractor Costs

Contractor costs include outside assistance for marketing/public relations/customer communications, 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.

Financing Plan

The initial start-up funding will be provided by MEA via short-term financing, likely a credit line that can be drawn upon as needed to cover expenditures. MEA will recover the principal and interest costs associated with the start-up funding via retail rates. It is anticipated that the start-up costs will be fully recovered within the first few years of the Program operations through retail rates.

Working Capital

Operating revenues from sales of electricity will be remitted to the Authority beginning on approximately day 47 of program operations, based the distribution utility's standard meter reading cycle of 30 days and its payment/collections cycle of 17 days. MEA will be responsible for providing the working capital needed to support electricity procurement as well as the working capital requirements related to program management, which will be included in the financing program 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 six years of program operations are shown in Chapter 7 below.

CHAPTER 5 – Program Phase-In

The Authority will phase-in the customers of its CCA Program over the course of two or more phases:

- Phase 1. MEA Member (municipal) accounts & a subset of residential, commercial and/or industrial accounts, comprising approximately 20 percent of total customer load.
- Phase 2. Remaining accounts, subject to economic and operational considerations.
- Phase 3. All remaining accounts, if necessary.

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 customer base of approximately 71,000 accounts. This approach also allows the Authority and its energy supplier(s) to address all system requirements (billing, collections, payments) under a phase-in approach to minimize potential exposure to uncertainty and financial risk by "walking" prior to ultimately "running".

MEA will offer service to all customers on a phased basis expected to be completed within twenty four months of initial service to Phase 1 customers. Phase 1 of the Program is targeted to begin on June 1, 2010. During Phase 1, MEA anticipates serving approximately 7,500 accounts totaling nearly 160 GWh. MEA is currently analyzing the potential composition of Phase 1 accounts in consideration of opportunities for maximizing energy efficiency and renewable energy impacts, synergies with local ordinances and other customer programs such as a planned municipally financed solar program, cost of service and customer load characteristics, and other operational considerations. Specific accounts to be included in Phase 1 will approximate 20 percent of MEA's total customer load and will be specifically defined after further analysis and consideration of the Board. The Board may, at its discretion, determine to expand Phase 1.

Phase 2 of the Program will commence following successful operation of the Program over a minimum 12-month term. Following this initial operating period, expected to continue for no more than 24 months, the Board will commence the process of completing the full roll out of the Program to all remaining customers in Phase 2. The Board may evaluate other phase-in options based on then-current market conditions, statutory requirements and regulatory considerations as well as other factors potentially affecting the integration of additional customer accounts.

CHAPTER 6 - Load Forecast and Resource Plan

Introduction

This Chapter describes MCE'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 MCE's retail customers, plus sufficient reliability reserves.

This integrated resource plan reflects a long-term, programmatic goal of 100 percent renewable energy supply. Within five years of program commencement (2015), this significant commitment to renewable resources is projected to result in MCE meeting over 60 percent 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. MCE's aggressive commitment to renewable generation adoption may 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 potential deployment of approximately 12 MW of new distributed solar capacity within the jurisdictional boundaries of MCE 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 percent Green and 25 percent 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 may be supplied from unit-specific resources such as efficient, low emission conventional generating resources and, potentially, hydroelectric resources, or by system power purchases.
- Increase the aggregate renewable energy supply of the Program to over 60 percent by 2015, based on projected levels of participation in MCE's two available generation tariffs.
- Continue increasing renewable energy supplies beyond 2015 based on resource availability and economic goals of the program.
- Develop partnership(s) with experienced public power developer(s) to responsibly evaluate development opportunities for Program-owned/controlled renewable generating capacity.
- Achieve incremental reductions in greenhouse gas emissions totaling as much as 17 percent of the Marin Communities' total GHG emissions (from all sectors, including transportation).

MEA will be responsible to comply with regulatory rules applicable to California load serving entities. MEA will arrange for the scheduling of sufficient electric supplies to meet the hour-by-hour demands of its customers. MEA will 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, MEA will be responsible for ensuring that its resource mix contains sufficient production from renewable energy resources needed to comply with the statewide renewable portfolio standards (currently 20 percent renewable energy supply by 2010). The resource plan will meet or exceed all of the applicable regulatory requirements related to resource adequacy and the renewable portfolio standard.

Resource Plan Overview

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

- Environmental responsibility and commitment to renewable resources;
- Price/rate stability;
- Reliability and maintenance of adequate reserves; and
- Cost effectiveness.

To meet these objectives and the applicable regulatory requirements, MEA's resource plan includes a diverse mix of 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 MEA's resource plan is to maximize use of renewable resources subject to economic and operational constraints. The result is a resource plan that will source over 60 percent of the resource mix from renewable resources by 2015. The planned resource mix is initially comprised of power purchases from third party electric suppliers and, in the longer-term, may also include renewable generation assets owned and/or controlled by MEA.

Once the Program demonstrates it can operate successfully, MEA may begin evaluating opportunities for investment in renewable generating assets, subject to then-current market conditions, statutory requirements and regulatory considerations. Any renewable generation owned by MEA or controlled under long-term power purchase agreement with a proven public power developer, could provide a portion of MEA'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. Any investment decisions will be made following thorough environmental reviews and in consultation with the Marin Communities' financial advisors, investment bankers, attorneys, and potentially with customer input.

As an alternative to direct investment, MEA may consider partnering 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. Such an arrangement could be structured to greatly reduce 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 MEA as it works to achieve increasing levels of renewable energy supply to its customers.

MEA'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, MEA will 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 12 MW of distributed solar by 2019.

MEA's proposed resource plan for the years 2010 through 2019 is summarized in the following table:

Marin Clean Energy
Proposed Resource Plan
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Marin Demand (GWh)										
Retail Demand	-93	-158	-758	-762	-765	-769	-773	-777	-781	-785
Distributed Generation	1	1	1	7	8	9	11	11	12	12
Energy Efficiency	0	1	1	15	15	15	15	15	15	16
Losses and UFE	-6	-11	-53	-52	-52	-52	-52	-53	-53	-53
Total Demand	-98	-167	-809	-791	-794	-797	-799	-803	-806	-810
Marin Supply (GWh)										
Renewable Resources										
Generation	0	0	0	0	0	219	219	219	219	219
Power Purchase Contracts	36	61	291	285	286	227	228	230	232	234
Total Renewable Resources	36	61	291	285	286	446	447	449	451	453
Conventional Resources										
Generation	0	0	0	0	0	0	0	0	0	0
Power Purchase Contracts	63	106	517	506	508	351	352	354	355	357
Total Conventional Resources	63	106	517	506	508	351	352	354	355	357
Total Supply	98	167	809	791	794	797	799	803	806	810
Energy Open Position (GWh)	0	0	0	0	0	0	0	0	0	0

Supply Requirements

The starting point for MEA'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". The electric sales forecast and load profile will be affected by MEA'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. It is anticipated that MEA's contracted energy supplier will bear a portion of the financial risks associated with deviations from the electric sales forecast during the initial operating period. It will be the obligation of this energy supplier to appropriately reflect these risks in the full requirements energy price. MEA's phased roll-out plan and assumptions regarding customer participation rates are discussed below.

Customer Participation Rates

Customers will be automatically enrolled in MCE'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. MCE anticipates an overall customer participation rate of approximately 80 percent during

Phase 1, when service is being offered to the service accounts that are affiliated with MCE's participating members (municipal accounts) and a subset of residential, commercial and/or industrial customers, totaling approximately 20 percent of total customer load. Participation rates are expected to be 80 percent of bundled service customers and 0 percent of direct access customers during Phase 2 based on experience with similar opt-out style municipal aggregation programs developed in other states and adjustments for assumed aggressive customer retention campaigns to be deployed by the incumbent utility. The participation rate is not expected to vary significantly among customer classes, in part due to the fact that MEA 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 will also be supported by MEA'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 MEA's public outreach and market research efforts continue to develop.

Customer Forecast

Once customers enroll in each phase, they will be switched over to service by MCE on their regularly scheduled meter read date over an approximately thirty day period. Approximately 250 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 increase to about 2,100 accounts per day. The number of accounts served by MCE at the end of each phase is shown in the table below.

Marin Clean Energy
Enrolled Retail Service Accounts
Phase-In Period (End of Month)

	Jun-10	Jan-11	Jan-12
Marin Customers			
Residential	6,858	6,892	61,462
Small Commercial	438	440	7,408
Medium Commercial	28	28	627
Large Commercial	3	3	93
Industrial	2	2	9
Street Lighting & Traffic	124	124	368
Ag & Pump.	-	-	152
Total	7,453	7,490	70,119

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

Marin Clean Energy
Retail Service Accounts (End of Year)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Marin Customers										
Residential	6,858	6,892	61,462	61,769	62,078	62,389	62,700	63,014	63,329	63,646
Small Commercial	438	440	7,408	7,445	7,483	7,520	7,558	7,595	7,633	7,672
Medium Commercial	28	28	627	630	634	637	640	643	646	650
Large Commercial	3	3	93	93	94	94	95	95	96	96
Industrial	2	2	9	9	9	9	9	9	9	9
Street Lighting & Traffic	124	124	368	370	372	374	376	377	379	381
Ag & Pump.	-	-	152	153	154	154	155	156	157	158
Total	7,453	7,490	70,119	70,470	70,822	71,176	71,532	71,890	72,249	72,611

Sales Forecast

MCE's forecast of kWh sales reflects the roll-out and customer enrollment schedule shown above. The annual electricity needed to serve MCE's retail customers increases from approximately 160 GWh in 2011 to approximately 800 GWh at full roll-out. Annual energy requirements are shown below.

Marin Clean Energy
Energy Requirements
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Marin Demand (GWh)										
Retail Demand	93	158	758	762	765	769	773	777	781	785
Distributed Generation	-1	-1	-1	-7	-8	-9	-11	-11	-12	-12
Energy Efficiency	0	-1	-1	-15	-15	-15	-15	-15	-15	-16
Losses and UFE	6	11	53	52	52	52	52	53	53	53
Total Load Requirement	98	167	809	791	794	797	799	803	806	810

Capacity Requirements

The CPUC's resource adequacy standards applicable to MEA require a demonstration one year in advance that MEA 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, MEA must demonstrate 100 percent of the peak load plus a minimum 15 percent reserve margin.

A portion of MEA's capacity requirements must be procured locally, from the Greater Bay area as defined by the CAISO and another portion must be procured from outside the Greater Bay Area. MEA 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 MEA's forecasted peak load. The applicable formulas are as follows:

<u>Authority Local Capacity Requirement Greater Bay:</u>

= [Authority coincident Peak/PG&E Planning Area coincident Peak (MW)] x Local Capacity Requirement Greater Bay Area

Authority Local Capacity Requirement Other PG&E:

= [Authority coincident Peak/PG&E Planning Area coincident Peak (MW)]/Local Capacity Requirement Other PG&E

MEA must demonstrate compliance or request a waiver from the CPUC requirement as provided for in cases where local capacity is not available.

The forward resource adequacy requirements for 2010 through 2012 are shown in the following tables:

Marin Clean Energy
Forward Capacity and Reserve Requirements
(MW)
2010 to 2012

Month	2010	2011	2012
January	-	37	154
February	-	36	164
March	-	27	132
April	-	26	128
May	-	25	118
June	30	30	136
July	28	28	132
August	30	30	151
September	32	31	141
October	33	33	140
November	37	37	157
December	38	38	154

MEA's plan ensures sufficient reserves are procured to meet its peak load at all times. MEA's annual capacity requirements are shown in the following table:

Marin Clean Energy
Capacity Requirements
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Demand (MW)										
Retail Demand	31	31	141	142	143	143	144	145	146	146
Distributed Generation	(1)	(1)	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(8)
Energy Efficiency	(0)	(0)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Losses and UFE	2	2	9	9	9	9	9	9	9	9
Total Net Peak Demand	33	33	143	143	142	142	143	143	144	144
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	5	5	21	21	21	21	21	21	22	22
Capacity Requirement Including Reserve	38	38	164	164	164	164	164	164	165	166

Local capacity requirements are a function of the PG&E area resource adequacy requirements and MCE's projected peak demand. MEA will need to work with the CPUC's Energy Division and potentially staff at the California Energy Commission to obtain the data necessary to calculate MEA's monthly local capacity requirement. A preliminary estimate of MEA's annual local capacity requirement for the ten year planning period ranges from approximately 16 to 72 MW as shown in the following table:

Marin Clean Energy
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
Authority Peak (MW)	33	33	143	143	142	142	143	143	144	144
Authority Share of Planning Area	0.1%	0.1%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
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	7	7	31	31	31	31	31	31	31	32
Authority Local Capacity Requirement Other PG&E	9	9	40	40	40	40	40	40	40	40

MEA intends to coordinate with PG&E and appropriate state agencies to manage the transition of responsibility for resource adequacy from PG&E to MEA during 2010. For system resource adequacy requirements, MEA will make month-ahead showings for each month of 2010 that MEA plans to serve load, and load migration issues would be addressed through the CPUC's approved procedures. Local resource adequacy requirements cannot be trued up monthly, and MEA intends to discuss an appropriate transition mechanism with PG&E. MEA will work with the California Energy Commission and CPUC prior to commencing service to customers to ensure it meets its local and system resource adequacy obligations for 2010 through its agreement with its chosen electric supplier.

Renewable Portfolio Standards Energy Requirements

Basic RPS Requirements

As a CCA, MEA is 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 renewables portfolio standard ("RPS") program and policies established in the state's Energy Action Plan, MEA must achieve a minimum renewable energy utilization rate of 20 percent by 2010. For purposes of determining MEA's renewable energy requirements, the same standards for RPS compliance that are applicable to the distribution utilities are assumed to apply to MEA.

The Commission has 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 one percent per year through 2009; 3) reporting their progress to the Commission; 4) utilizing flexible compliance mechanisms; and 5) being subject to penalties and penalty processes. Future resource plans adopted by MEA will 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 through 2009 or 20 percent of retail sales by 2010, 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 years, and the "Incremental Procurement Target" ("IPT").

The CPUC's flexible compliance rules allow a load serving entity to defer up to 25 percent of the prior year's retail sales without explanation, as long as the shortfall is made up within three years. Shortfalls greater than 25 percent of the prior year's retail sales 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. Noncompliance will result in penalties of 5 cents per kWh, capped at $25 million per year.

Marin Energy Authority's Renewable Portfolio Standards Requirement

Because MEA will have no baseline of renewable energy procurement (i.e., no existing contracts or resources), its first year APT calculated as described above is 18,409 MWh, which represents 20 percent of projected retail sales. MEA's annual RPS requirements are shown in the table below.

Marin Clean Energy
RPS Requirements
(MWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales	92,047	155,813	755,864	739,447	741,998	744,567	747,154	750,774	753,501	757,328
Baseline	-	18,409	31,163	151,173	147,889	148,400	148,913	149,431	150,155	150,700
Incremental Procurement Target	18,409	12,753	120,010	(3,283)	510	514	518	724	545	765
Annual Procurement Target	18,409	31,163	151,173	147,889	148,400	148,913	149,431	150,155	150,700	151,466
% of Current Year Retail Sales	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%

Based on MEA's 25 percent minimum renewable energy supply content and voluntary participation in MCE's 100 percent renewable energy supply option, MEA anticipates that it will significantly exceed the minimum RPS requirements as shown below.

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales (MWh)	92,047	155,813	755,864	739,447	741,998	744,567	747,154	750,774	753,501	757,328
Annual RPS Target (Minimum MWh)	18,409	31,163	151,173	147,889	148,400	148,913	149,431	150,155	150,700	151,466
Program Target (% of Retail Sales)	39%	39%	39%	39%	39%	60%	60%	60%	60%	60%
Program Renewable Target (MWh)	**35,861**	**60,711**	**291,398**	**285,069**	**286,052**	**445,651**	**447,200**	**449,366**	**450,999**	**453,289**
Surplus In Excess of RPS (MWh)	**17,451**	**29,548**	**140,225**	**137,179**	**137,653**	**296,738**	**297,769**	**299,212**	**300,298**	**301,824**
Annual Increase (MWh)	35,861	24,850	230,687	(6,329)	983	159,599	1,549	2,167	1,632	2,291

Resources

Once the Program demonstrates it can operate successfully, MEA may begin evaluating opportunities for investment in renewable generating assets, subject to then-current market conditions, statutory requirements and regulatory considerations. Any renewable generation owned by MEA or controlled under long-term power purchase agreement with a proven public power developer, could provide a portion of MEA'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. Any investment decisions will be made following thorough environmental reviews and in consultation with the Marin Communities' financial advisors, investment bankers, attorneys, and potentially with customer input.

As an alternative to direct investment, MEA may consider partnering 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. Such an arrangement could be structured to greatly reduce 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 MEA as it works to achieve increasing levels of renewable energy supply to its customers.

Purchased Power

Power purchased from utilities, power marketers, public agencies, and/or generators will likely be the exclusive source of supply from 2010 to 2014 (MEA may consider the development of certain renewable energy projects, subject to Board approval, which may supply electric generation to MEA customers as soon as January 2015) and may still remain a significant source of power in the event that MEA considers the development of its own renewable generation assets. During the period from 2010 – 2015, MCE will contract to 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. Based on terms established in this third-party contract, MEA will be able to substitute electric energy generated by MEA-owned/controlled renewable resources for contract quantities in the event that such resources become operational during the delivery period.

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. A mix of short and long term power purchases will be used to meet the hour-by-hour demand requirements of MCE's customers, and prices will be predominantly fixed for the contract term.

Renewable Resources

MEA will initially secure necessary renewable power supply from its third party electric supplier(s). Qualified renewable energy resources must supply a minimum of 25 percent of customer energy requirements, which equates to approximately 40,000 MWh in 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; and
- Wind.

MEA may supplement the renewable energy provided under the initial full requirements contract with direct purchases of renewable energy or potentially with investments in renewable energy facilities. Renewable technologies that are predominantly 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.[3] The vast majority of the resource potential identified by the CEC is located in Southern California, concentrated in four specific 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

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[3] 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 percent Renewable Energy Target; J.Hamrin, R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger; November 2005.

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 MCE'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 MCE'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, studies indicate 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[4]
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, MEA 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 has transitioned from the former zonal congestion pricing model to a nodal model when it implemented its Market Redesign and Technology Update (MRTU).[5] The ideal energy source would be located within the County, near the load center. The next best 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

[4] 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.

[5] 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 expands the number of congestion pricing points, creating thousands of locational pricing nodes.

approximately 1,300 GWh per year.[6] 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, MCE will look first to local renewable resources and then to procurement of renewable energy from outside the area. MEA 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.

For planning purposes, MEA 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, biogas, 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; and
- 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).[7] 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 had applied for transmission interconnections with the CAISO.[8] According to the CAISO, about one half of all projects in the queue ultimately are developed. These projects represent proposed renewable projects that MCE could potentially use to meet its renewable energy requirements, once the necessary transmission upgrades are completed.

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.[9]

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[6] Increasing Renewable Energy Resources in the County of Marin, Jody London Consulting, November 11, 2007.

[7] 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.

[8] 2008 CAISO Transmission Plan: A Long-Term Assessment of the California ISO's Controlled Grid (2008-2018), California Independent System Operator, January 2008.

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

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 percent renewable energy sales by 2010 and potentially 33 percent 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).

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, MEA would have the same access as PG&E to this transmission once the projects are completed. For mid and long term planning purposes, MEA should anticipate procurement from the following types of large scale renewable resources[10]:

- Wind imports from the Tehachapi Area;
- Wind imports from the Pacific Northwest;
- Geothermal imports from Nevada;
- Geothermal imports from the Imperial Valley; and
- 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 MEA's future 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 MEA'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 MEA's load zone, as defined by the CAISO.

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

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, MEA may 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 may be utilized. Actual procurement of renewable resources can be conducted through a competitive solicitation, either directly by MEA or in conjunction with another public agency. MEA may also 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 MEA will be in competition for renewable resources with the three investor owned utilities, which together require nearly 12 million MWh annually to meet their RPS requirements by 2010. Over the longer term, the transmission expansion plans of the utilities will provide additional resource options for MEA. The Authority, working with third party electric suppliers, will need to be aggressive in pursuing the renewable resources that are currently available. In contrast to PG&E, which is motivated by regulatory compliance with the Renewable Portfolio Standards, MEA will elevate procurement and potential 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

Once the Program demonstrates it can operate successfully, MEA may begin evaluating opportunities for investment in renewable generating assets, subject to then-current market conditions, statutory requirements and regulatory considerations. Any renewable generation owned by MEA or controlled under long-term power purchase agreement with a proven public power developer, could provide a portion of MEA'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. Any investment decision will be subject to Board approval and will only be made following thorough environmental reviews and in consultation with the Marin Communities' financial advisors, investment bankers, attorneys, and potentially with customer input.

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.[11] 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.[12]

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

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

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 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 exceed $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 MEA's integrated resource plan. As described below there are opportunities for significant cost effective energy efficiency programs within the region, and MEA will 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 MEA'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; and
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 Marin County 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. The following table summarizes these findings below:

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."[13] The American Council for an Energy-Efficient Economy (ACEEE) reports for states already operating substantial energy efficiency programs energy efficiency goals of one percent, as a percentage of energy sales, is a reasonable level to target.[14] Forecast achievable energy efficiency equal to 1.1 percent of the CCA's forecast energy sales, as indicated in the table 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 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 is to increase annual savings through energy efficiency programs to two percent (combined MCE 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. MEA programs will 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:[15]

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

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

[15] 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.

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.

MEA plans to hire Program staff that will develop specific energy efficiency programs that will obtain these energy savings. MCE will also seek requisite PGC program funding from the CPUC to administer the energy efficiency programs. Additional details of MCE's energy efficiency plan will be developed once the CCA Program is staffed and has begun operations.

Demand Response

Demand response programs provide incentives to customers to reduce demand upon request by the load serving entity (i.e., MCE), 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. This resource plan anticipates that MCE'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 MEA intends to recruit those customers that have shown a willingness to participate in utility programs into MCE's demand response programs.[16] The goal for this resource plan is to meet 5 percent 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 8 MW of peak demand enrolled in MEA's demand response programs. Achievement of this goal would displace approximately 26 percent of MEA's local capacity requirement within the Greater Bay Area.

[16] These utility 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). MEA plans to develop its own demand response programs, which may be similar to those currently administered by the incumbent utility.

Marin Clean Energy
Demand Response Goals
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Capacity Requirement (MW)	38	38	164	164	164	164	164	164	165	166
Demand Response Target	-	2	8	8	8	8	8	8	8	8
Percentage of Local Capacity Requirment	0%	26%	26%	26%	26%	26%	26%	26%	26%	26%

MEA will 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.[17]

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 MEA'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. MEA will likely utilize experienced third party contractors to design, implement and administer its demand response programs.

Distributed Generation

Consistent with MEA's environmental policies and the state's Energy Action Plan, clean distributed generation is a significant component of the integrated resource plan. MEA will work with state agencies and PG&E to promote deployment of photovoltaic (PV) systems within MEA's jurisdiction, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public goods surcharges.

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. MEA 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, MEA plans to 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 MEA.

[17] For example, the annual customer incentive in PG&E's Capacity Bidding Program is fixed at $43.35 per kW-year in 2007 - 2008.

MEA's CCA customers will contribute funds to the California Solar Initiative (CSI) through the public goods charge collected by PG&E, and will 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 percent 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 8 MW should be deployed within the jurisdictional boundaries of MEA.

California Solar Initiative Deployment

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
IOU Territory Target (MW)	705	882	1,058	1,235	1,411	1,587	1,764	1,940	1,940	1,940
Total Funding ($Millions)	240	240	240	160	160	160	5	0	0	0
PG&E Funding ($Millions)	105	105	105	70	70	70	2	0	0	0
PG&E Incentives Share	44%	44%	44%	44%	44%	44%	40%	40%	40%	40%
PG&E Area Deployment (MW)	309	386	463	540	617	694	705	776	776	776
Marin Share of PG&E Load	0.2%	0.2%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Marin Solar Deployment (MW)	1	1	5	6	6	7	7	8	8	8

The Authority will work to ensure that customers within its jurisdiction take full advantage of this solar incentive and will develop programs of its own with the goal of exceeding the deployment targets shown above by at least 50 percent (a minimum of 12 MW of distributed solar installations are targeted within the jurisdictions of the Member Agencies).

CHAPTER 7 – Financial Plan

This Chapter examines the monthly cash flows expected during the phase-in period of the CCA Program and identifies the anticipated financing requirements for the overall CCA Program by MEA. It includes estimates of program startup costs, including the necessary staffing and capital outlays which will commence once the CPUC accepts the Implementation Plan submitted by MEA. It also describes the requirements for working capital and long-term financing for the potential investment in renewable generation, consistent with the resource plan contained in Chapter 6.

Description of Cash Flow Analysis

This cash flow analysis estimates the level of working capital that will be required during the phase-in period. 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 phase-in period, and specifically account for the transition or "Phase-In" of CCA Customers from PG&E's service territory described in Chapter 5.

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;
- CCA Bond Premiums;
- Interest Expense; and
- Franchise Fees.

The focus of this cash flow analysis is during the phase-in period.

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 MEA's CCA Program provides a Light Green Tariff at comparable generation rates to those of the existing distribution utility for each customer class and a 100 percent Green Tariff at a premium reflective of incremental renewable power costs.

Over time, MCE's preference for renewable energy will significantly reduce its exposure to volatile input costs (fuel – natural gas) associated with natural gas-fired generation, which are expected to increase steadily, and potentially significantly, for the foreseeable future. Because a significant portion of MEA's power supply will be from renewable energy sources, upward price pressures on its power supply should be significantly reduced over long-term operations.

Projected long-term cost savings can be passed on to Program customers in the form of lower generation rates or can be applied to the procurement of additional renewable energy supplies (moving the program's renewable energy supply closer to its 100 percent goal), energy efficiency programs or other energy/climate initiatives within the scope of broad-based powers established for MEA. Ultimately, MEA will have flexibility when making these decisions and can 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 MEA to move through the CCA phase-in 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 MEA, 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 the assumptions regarding payment streams, the cash flow analysis identifies funding requirements while recognizing the potential lag between payments received and payments made during the phase-in period. The estimated financing requirements for the phase-in period, including working capital, based on the phase-in of customers as described above is approximately $10 million. Working capital requirements reach this peak immediately after enrollment of the Phase 2 customers.

CCA Program Implementation Feasibility Analysis

In addition to developing a cash flow analysis which estimates the level of working capital required to get MEA through full CCA phase-in, a summary analysis that evaluates the feasibility of the CCA program during the phase-in 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 are shown in the following table. Under these assumptions, over the entire phase-in period the CCA program is projected to accrue a reserve account balance of approximately $10 million.

Marin Clean Energy
Summary of CCA Program Phase-In
(January 2010 through December 2015)

CATEGORY	2010	2011	2012	2013	2014	2015	TOTAL
I. REVENUES FROM OPERATIONS ($):							
(A) ELECTRICITY SALES:							
RESIDENTIAL	$10,345,313	$18,237,976	$44,803,557	$47,363,888	$49,739,734	$50,581,455	$221,071,923
GENERAL SERVICE (A-1)	$195,562	$323,134	$9,560,233	$10,106,559	$10,613,520	$10,793,127	$41,592,134
SMALL TIME-OF-USE (A-6)	$548,920	$847,436	$3,506,281	$3,706,650	$3,892,581	$3,958,453	$16,460,321
ALTERN. RATE FOR MEDIUM USE (A-10)	$332,197	$550,463	$12,914,056	$13,652,039	$14,336,846	$14,579,462	$56,365,062
500 - 900kW DEMAND (E-19)	$213,292	$344,629	$5,253,601	$5,553,822	$5,832,410	$5,931,109	$23,128,863
1000 + kW DEMAND (E-20)	$588,553	$951,828	$4,056,909	$4,288,744	$4,503,874	$4,580,091	$18,969,999
STREET LIGHTING & TRAFFIC CONTROL	$179,032	$307,510	$486,184	$513,967	$539,748	$548,882	$2,575,323
AGRICULTURAL PUMPING	$0	$0	$435,038	$459,898	$482,968	$491,141	$1,869,045
TOTAL REVENUES	$12,402,869	$21,562,977	$81,015,857	$85,645,566	$89,941,680	$91,463,721	$382,032,670
II. COST OF OPERATIONS ($):							
(A) ADMINISTRATIVE & GENERAL (A&G):							
STAFFING	$940,582	$1,112,400	$2,595,600	$2,673,468	$2,753,672	$2,836,282	$12,912,004
CONTRACTOR COSTS	$1,555,000	$1,545,000	$2,163,000	$2,227,890	$2,294,727	$2,363,569	$12,149,185
IOU FEES (INLCUDING BILLING)	$265,000	$123,600	$1,050,600	$1,082,118	$1,114,582	$1,148,019	$4,783,919
CONTRACT STAFF	$165,000	$185,400	$222,480	$229,154	$236,029	$243,110	$1,281,173
SUBTOTAL - A&G	$2,925,582	$2,966,400	$6,031,680	$6,212,630	$6,399,009	$6,590,980	$31,126,281
(B) CCA PROGRAM OPERATIONS:							
ELECTRICITY PROCUREMENT	$8,011,877	$14,514,684	$68,623,916	$70,433,949	$72,178,465	$71,633,923	$305,396,814
EXIT FEES	$1,948,481	$2,300,242	$7,843,729	$5,674,199	$4,401,313	$5,231,056	$27,399,020
RENEWABLE PORTFOLIO ADJUSTMENT	$184,705	$313,717	$1,591,481	$1,599,439	$1,607,436	$3,295,565	$8,592,343
SUBTOTAL - CCA PROGRAM OPERATONS	$10,145,064	$17,128,642	$78,059,126	$77,707,587	$78,187,213	$80,160,543	$341,388,176
TOTAL COST OF OPERATION	$13,070,646	$20,095,042	$84,090,806	$83,920,217	$84,586,222	$86,751,523	$372,514,458
CCA PROGRAM SURPLUS / (DEFICIT)	($667,777)	$1,467,934	($3,074,949)	$1,725,349	$5,355,458	$4,712,198	$9,518,212

The surpluses achieved during the phase-in period serve as operating reserves for MEA in the event that operating costs (such as power purchase costs) exceed collected revenues for short periods of time.

Marin Clean Energy Financings

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

CCA Program Start-up and Working Capital (Phase 1)

As previously discussed, the anticipated start-up and working capital requirements for the CCA Program are $2 million. Once the CCA Program is up and running, these costs would be recovered from the retail customers through retail rates. 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 MEA's Board of Directors regarding initial rates for Phase 1 customers.

It is assumed that this financing will be via a letter of credit (LOC), which would allow MEA to draw cash as required. This financing would need to commence no later than early 2010.

CCA Program Working Capital (Phase 2)

The next potential financing would be working capital for Phase 2. As mentioned above, this could be just an extension (increase) of the LOC for the Program's start-up and working capital. Depending upon market conditions, and payment terms established with the third-party supplier, it may be necessary to increase the LOC to an approximate amount of $10 million (or more) in "float" for the start of Phase 2. This number would be refined as the CCA Program was operational and bids were received and evaluated from power providers for the Phase 2 load requirements.

Renewable Resource Project Financing

MEA's CCA Program may consider large project financings for renewable resources (likely wind, solar, biomass or geothermal), which may total as much as $375 million (combined). These financings would only occur after a sustained period of successful Program operation and after appropriate project opportunities are identified and subjected to appropriate environmental review. Such financing would occur no sooner than late 2012 – early 2013. In the event that such financing becomes necessary, funds would include any short-term financing for the renewable resource project development costs, and would extend over a 20- to 30-year term.

The security for such bonds would be a hybrid of the revenue from sales to the retail customers of MEA, including a Termination Fee as described in Chapter 9, and the renewable resource project itself.

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

Proposed Financing	Estimated Total Amount	Estimated Term	Estimated Issuance
1. Start-Up and Working Capital (Phase 1)	$2 million	No longer than 7 years	Early 2010
2. Working Capital (Phase 2)	$10 million	No longer than 5 years	Mid 2011
3. Potential Renewable Resource Project Financings	$375 million (aggregate)	20-30 years	Late 2012 – Early 2013

CHAPTER 8 - 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. Initial Program rates will be approved by the Board and included in the initial customer opt-out notices for customer comparison purposes.

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

MEA 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 MEA, comprised of the jurisdictional boundaries of its members. It is not anticipated that each member would establish its own rates.

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

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

Each of these objectives is described below.

Rate Competitiveness

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

Competitive rates will be critical to attracting and retaining key customers. As discussed above, the principal long-term Program goal is to achieve 100 percent renewable energy supply subject to economic and operating constraints. As previously discussed, the Program will significantly increase renewable energy supply to Program customers, relative to the incumbent utility, by offering two distinct rate tariffs. The default tariff for Program customers will be the 25 percent Light Green Tariff, which will maximize renewable energy supply (minimum 25 percent) while maintaining generation rates that are equivalent to PG&E. MEA will also offer its customers a voluntary Deep Green Tariff, which will supply participating customers with 100 percent renewable energy supply at rates that reflect the Program's cost for procuring necessary energy supplies.

As previously suggested, the default tariff for Program customers will be the Light Green Tariff. Consistent with this MEA policy, participating qualified low- or fixed-income households, such as those currently enrolled in the California Alternate Rates for Energy (CARE) program, will be automatically enrolled in the Light Green Tariff and will continue to receive related discounts on monthly electricity bills. Based on projected participation in each tariff, the amount of renewable energy supplied to Program customers as a percentage of the Program's total energy requirements is projected to exceed 60 percent in 2015. This estimate is based on discussions with local policy makers, municipal management, potential suppliers and members of the public.

Rate Stability

MEA will 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 MEA's rates will 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. MEA will have more flexibility in procurement and ratesetting than PG&E to stabilize electricity costs for customers.

Equity among Customer Classes

MEA's policy will 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 MEA'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

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

Rate Design

Marin Clean Energy's rate designs will initially generally mirror the structure of PG&E's generation rates so that similar rate impacts can be provided to MEA'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. MEA's rates may 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). MEA will 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 MEA's program. MEA may also introduce new rate options for customers, such as rates designed to encourage economic expansion or business retention within MEA's service area.

Net Energy Metering

Customers with on-site generation eligible for net metering from PG&E will be offered a net energy metering rate from MEA. 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 MEA's net energy metering tariff will apply to the generation component of the bill, and the PG&E net energy metering tariff will apply to the utility's portion of the bill. MEA will pay customers for excess power produced from net energy metered generation systems in accordance with the rate designs adopted by the MEA Board.

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 General Manager, with support of appropriate staff, advisors and committees, will 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 will 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 will be able to provide comment on the proposed rate changes.

MEA will initially adopt customer noticing requirements similar to those the CPUC requires of PG&E. 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 MEA 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, MEA 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 MEA 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.

CHAPTER 9 – Customer Rights and Responsibilities

This chapter discusses customer rights, including the right to opt-out of the CCA Program, as well as obligations customers undertake upon agreement to enroll in the CCA Program. All customers that do not opt out within 30 days of the fourth opt-out notice will have agreed to become full status program participants and must adhere to the obligations set forth below, as may be modified and expanded by the MEA Board from time to time.

By adopting this Implementation Plan, the MEA Board approved the customer rights and responsibilities policies contained herein to be effective at Program initiation. The Board retains authority to modify program policies from time to time at its discretion.

Customer Notices

At the initiation of the customer enrollment process, a total of four notices will 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. MEA will 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, MEA 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 start of MEA service would result in customer transfer to utility service with no penalty. Such customers will be obligated to pay MEA'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 MEA.

New customers who establish service within the Program service area will be automatically enrolled in the Program and will have sixty days from the start of MEA service to opt out of the Program. Such customers will be provided with two opt-out notices within this sixty-day post enrollment period. MEA's Board of Directors will have the authority to implement entry fees for customers that initially opt out of the Program, but later decide to participate. Entry fees, if deemed necessary, 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 will be allowed to terminate their participation subject to payment of a Termination Fee, which will be similar to the "Cost Responsibility Surcharge" fees charged by PG&E to customers that take generation service from alternative suppliers. The Termination Fee may 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 may 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 will 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 MEA is unable to recover the costs of supply commitments attributable to the customer that is terminating service. PG&E will collect the Administrative Fee from returning customers as part of the final bill to the customer from the CCA Program and will collect the Cost Responsibility Charge (CRC) as a lump sum or on a monthly basis pursuant to a negotiated servicing agreement between MEA 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 MEA'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 MEA's Governing Board as part of the annual ratemaking process.

The long-term financial projections contained in Chapter 7 indicate that MEA may be able to offer rates that are equivalent to those charged by PG&E and that MEA's supply portfolio is projected to be competitive in the marketplace in part because of the financing advantages that MEA enjoys. Under those conditions, most customers would not be expected to terminate their service with MEA to return to the utility. Furthermore, if customers do terminate service, MEA should be able to re-market the excess supply and fully recover its costs. Although the Cost

Recovery Charge may not be needed for recovery of stranded costs, MEA's ability to assess a Cost Recovery Charge, if necessary, is an important condition for obtaining financing for MCE's power supply. The low cost financing will, in turn, enable MEA 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 will likely need to post cash collateral to match its credit exposure to the Program's electric supplier(s), which would increase costs to MEA customers.

The circumstance that would trigger application of the CRC would be if PG&E rates unexpectedly drop below those of MEA and customers wish to leave the Program to return to PG&E or take service from a different generation supplier. In that scenario, the CRC would reduce some of the customer benefits from switching back to PG&E or the alternative supplier.

The Termination Fee will 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 MEA's Board of Directors, subject to MEA's customer noticing requirements. As previously noted, customers that opt-out during the statutorily mandated notification period will not pay the Termination Fee that may be imposed by MEA.

Customers electing to terminate service after the initial notification period that provided them with at least four opt-out notices 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 after the initial notification period that provided them with at least four opt-out notices 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

MEA will establish policies covering confidentiality of customer data. MEA's policies will 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 MEA's discretion or as required by law or regulation.

Responsibility for Payment

Customers will be obligated to pay MEA charges for service provided through the date of transfer including any applicable Termination Fees. Pursuant to current CPUC regulations, MEA will not be able to direct that electricity service be shut off for failure to pay MEA'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 MEA's Board based on experience or regulatory changes that would provide MEA 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 MEA'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 MEA'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 10 - Procurement Process

Introduction

This Chapter describes MEA's initial procurement policies and the key third party service agreements by which MEA will obtain operational services for the CCA Program. By adopting this Implementation Plan, the Authority's Board of Directors approved the general procurement policies contained herein to be effective at Program initiation. The Board retains authority to modify Program policies from time to time at its discretion.

Procurement Methods

MEA will enter into agreements for a variety of services needed to support program development, operation and management. It is anticipated MEA will 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.

MEA will 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 MEA's General Manager or Board of Directors.

The General Manager will 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 will generally mirror the authority for entering into the agreements.

Key Contracts

Electric Supply Contract

MEA is in the process of negotiating a long-term (through May 31, 2015) electricity supply contract with a qualified provider. For the initial five years of program operations (6/1/2010 through 5/31/2015), the third party provider will supply electricity to customers under a full requirements contract between the provider and MEA. For the post-2015 period, MEA will be obligated to complete additional solicitations to secure its resource portfolio. MEA will seek to begin such procurement sufficiently in advance so that the transition from the initial full requirements contract occurs smoothly, avoiding dependence on market conditions existing at any single point in time. Under the initial full requirements contract, the supplier commits to serve the composite electrical loads of customers in the Program. The supplier is responsible for ensuring that a certified Scheduling Coordinator schedules the loads of all customers in the Program, providing necessary electric energy, capacity/resource adequacy requirements, renewable energy and ancillary services. The supplier is wholly responsible for the Program's portfolio operations functions and managing the predominant supply risks for the term of the contract. The supplier must meet the Program's renewable energy goals and comply with all applicable resource adequacy and regulatory requirements imposed by the CPUC or FERC.

Certain financial risks related to changes in Program loads during the term of the agreement are borne by the supplier, within the ranges specified in the electric supply agreement. 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 25 percent throughout the delivery period. The supplier is also required to procure sufficient renewable energy to meet the requirements of serving customers enrolled in the Deep Green MEA service option.

MEA anticipates executing the electric supply contract for Phase 1 loads in February 2010. The contract for Phase 2 loads will be executed approximately four months prior to commencement of service to Phase 2 customers.

Data Management Contract

A data manager will provide the retail customer services of billing and other customer account services (electronic data interchange or EDI with PG&E, billing, remittance processing, and 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 will be selected to perform all of the data management functions.[18]

The data manager is responsible for the following services:

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

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

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

It is anticipated that MEA will execute a contract for data management services in January 2010.

Electric Supply Procurement Process

MEA issued a request for proposals for full requirements energy, renewable energy and resource adequacy capacity as part of a competitive solicitation process. The short list of potential energy suppliers selected as a result of this process reflected a highly qualified pool of suppliers for further negotiations, which will be completed prior to the Authority's registration as a CCA.

The timeline for the initial solicitation is as follows:

Release RFP	May 11, 2009
Pre-Bid Meeting	May 27, 2009
Deadline for Question Submittal	June 10, 2009
Responses Due	July 20, 2009
Notification of Short List	August 11, 2009
Short List Interviews	Week of August 17, 2009
Contract Negotiation	August - November, 2009
Contract Approval and Execution	February 2010
Commence Service	June 2010

On July 20, 2009, MEA received bids for third-party power supply from twelve companies. The bids were ranked based upon the following criteria:

- Price of energy supply;
- Financial viability of respondent;
- Operational experience of respondent;
- Reliability and environmental attributes of proposed power supply; and
- Demonstrated understanding of Program requirements.

Based upon these criteria, subsequent negotiations and final energy pricing MEA selected three energy suppliers, described below, for the short list of firms who may provide electricity for the Program under an initial full requirements contract. Final supplier selection is scheduled to be made by the MEA Board in February 2010.

Shell Energy North America

Shell Energy North America (US), L.P. (SENA) is a leading supplier of energy and associated services in North America. SENA provides natural gas, electrical energy and capacity, scheduling and asset optimization, risk management, and renewable energy and environmental products to a wide variety of customers. SENA is 100% owned by Royal Dutch Shell Company and its subsidiaries. SENA owns and manages a variety of energy assets in the West, including generation, a portfolio of renewable energy, transmission capacity, natural gas production, liquefied natural gas capacity, natural gas storage capacity, and natural gas pipeline capacity.

SENA's West Region operation includes regional offices in San Diego, Portland, Spokane, Berkeley, Salt Lake City, Denver and Mexico City, with 7 X 24 power and gas operations in San Diego and Spokane.

SENA has an extensive list of public and privately owned customers in the West, including all WECC region investor-owned utilities, twenty-five publicly owned (municipal) electric utilities/other public agencies in California, and publicly owned utilities/public agencies in neighboring states. SENA's West Region full requirements power experience includes provision of retail electric service, including provision of resource adequacy, for direct access customers in California.

Renewable energy products offered by SENA include renewable energy, bundled renewable energy, landfill gas, biogas and renewable energy credits. SENA states it is actively developing renewable portfolios and provides related services such a scheduling and shaping of intermittent energy. SENA's affiliate, Shell WindEnergy, develops and owns wind generation in California and other parts of North America. SENA also offers a variety of environmental products including emission offsets and other carbon reducing products.

SENA is rated A- by S&P and A2 by Moody's.

Constellation Energy Commodities Group

Constellation Energy Commodities Group, Inc. ("CCG") is a wholly owned subsidiary of Constellation Energy Group, Inc. with experience in serving wholesale and retail load throughout North America. In 2008 CCG reports it served a peak load of approximately 27,000 MW. CCG serves approximately 750 MW of direct access load in California and has been a Scheduling Coordinator for nine years. CCG's portfolio management team consists of several traders managing day-ahead and term positions, as well as at least 8 real-time traders managing positions on an hourly basis. CCG also has several Originators focused on both adding to and optimizing its load-serving positions. CCG's team has several decades of combined experience serving load in both California and across North America. CCG owns and operates 9,042 MW of generation throughout North America, including several Qualifying Facilities in California.

CCG 's parent company is rated BBB by S&P and Baa3 by Moody's.

Macquarie Cook Power Inc.

Macquarie Cook Power Inc. (MCP) is a Houston based electricity trading and marketing company servicing North American electricity generators, utilities, municipalities and cooperatives. MCP is a wholly owned subsidiary of Macquarie Group Limited, based in Sydney, Australia, a diversified, global financial services organization with total assets under management of US$200 billion. MCP was established in 2006 and currently trades physically and/or financially in PJM, NYISO, NEPOOL, MISO, CAISO, and the WECC markets. MCP staff has worked on all aspects of the development and management of generation including, fuel management for and power sales and scheduling of the units. MCP maintains a fully-staffed 24 hour real time trading desk.

MCP parent company, Macquarie Bank Limited, is rated A by S&P and A1 by Moody's.

MCP's relevant experience includes: recent acquisition of rights to hydro-electric facilities in the Pacific Northwest, energy management agreements for two peaking natural gas plants in Southern California, management of a combined cycle plant in Southern New Jersey through a tolling agreement, provision of full requirements load following service in Maryland and New Jersey, and provision of shaping and firming services for imports of renewable energy into California to meet RPS requirements.

Chapter 11 – Contingency Plan for Program Termination

Introduction

This Chapter describes the process to be followed in the case of Program termination. By adopting this Implementation Plan, the Authority's Board of Directors approved the general termination process contained herein to be effective at Program initiation. In the unexpected event that MEA 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. The Board retains authority to modify program policies from time to time at its discretion.

Termination by Marin Clean Energy

The Authority plans 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/Town Councils) decide to terminate the Program, each governing body would be required to adopt a termination ordinance or resolution and provide adequate notice to MEA consistent with the terms set forth in the JPA Agreement. Following such notice, MEA would vote on Program termination subject to a two-tiered vote, as described in the JPA Agreement. 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.

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 MEA 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.

MEA will post a bond or 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. MEA will post a bond in the appropriate amount as part of its registration materials and will maintain the bond in the required amount, as necessary.

Termination by Members

The JPA Agreement defines the terms and conditions under which Members may terminate their participation in the program.

CHAPTER 12 – Appendices

Appendix A: Authority Resolution 2009-10

Appendix B: Marin Energy Authority Joint Powers Agreement