COMMUNITY CHOICE AGGREGATION PILOT PROJECT

APPENDIX H:

Berkeley, Emeryville, Oakland Business Plan

Arnold Schwarzenegger
Governor

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission

Prepared By:
Local Government Commission

April 2009
CEC-500-2008-091-APH

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Appendix H-1: Proposed Joint Powers Agreement and Principals for CCA Project

Agreement

East Bay Power Authority
- Joint Powers Agreement -

Effective _____________, 2007

Among The Following Parties:

[City of Berkeley]
[City of Emeryville]
[City of Oakland]

EAST BAY POWER AUTHORITY
JOINT POWERS AGREEMENT

This **Joint Powers Agreement** ("Agreement"), effective as of __________________, 2007, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 *et seq*.) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit B. The parties to this Agreement are either California incorporated municipalities or California counties, and shall be referred to hereafter as "Parties." The term "Parties" shall also include any incorporated municipality or county added to this Agreement in accordance with Section 3.2.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law to, among other things, purchase, supply, and aggregate electricity for themselves and their inhabitants (*see, e.g.,* California Public Utilities Code Sections 366.2).
2. The Parties have been investigating and analyzing a program for the implementation of Community Choice Aggregation ("CCA"), an electric service option available to cities and counties pursuant to Assembly Bill 117 (Stat. 2002, ch. 838) ("AB 117").
3. The Parties desire to establish a separate public agency, known as the East Bay Power Authority ("Authority"), under the provision of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.) ("Act") in order to collectively study, promote, develop, and conduct electricity-related programs, including specifically a program relating to CCA ("CCA Program").

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1

CONTRACT DOCUMENTS

1.1 **Definitions**. Capitalized terms used in this Agreement shall have the meanings specified in Exhibit A, unless the context requires otherwise.

1.2 **Documents Included**. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

Exhibit A: Definitions
Exhibit B: List of the Parties

ARTICLE 2
FORMATION OF THE EAST BAY POWER AUTHORITY

2.1 **Effective Date and Term**. This Agreement shall become effective and the East Bay Power Authority shall exist as a separate public agency on the date this Agreement is executed by at least two Initial Participants. The Authority shall provide notice of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.4, subject to the rights of the Parties to withdraw from the Authority.

2.2 **Initial Parties**. During the first 90 days after the Effective Date, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party and is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

2.3 **Formation**. There is formed as of the Effective Date a public agency named the East Bay Power Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. Unless otherwise agreed, the debts, liabilities, and obligations of the Authority shall not be debts, liabilities or obligations of the Parties. The foregoing disclaimer shall not apply to a Party with respect to which this Agreement has terminated, as specified in Article 6**,** to the extent of such Party's obligations incurred while a party to this Agreement.

2.4 **Purpose**. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party to study, promote, develop, and conduct electricity-related programs, and to exercise all other powers necessary and incidental to accomplishing said purpose. Without limiting the generality of the foregoing, the Parties intend for this Agreement to be used as a contractual mechanism by which the Parties may initially participate as a group in the CCA Program, as further described in Section 5.1. The Parties intend that a subsequent agreement (Program Agreement 1) shall define the terms and conditions associated with the actual implementation of the CCA Program.

2.5 **Powers**. The Authority shall have all the powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to do all acts necessary or advisable to fulfill the purpose of this Agreement and programs implemented pursuant to this Agreement, including, but not limited to, each of the following:

2.5.1 make and enter into contracts;

2.5.2 employ agents and employees;

2.5.3 acquire, construct, manage, maintain, and operate any buildings, works or improvements;

2.5.4 acquire by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;

2.5.5 lease any property;

2.5.6 sue and be sued in its own name;

2.5.7 incur debts, liabilities, and obligations;

2.5.8 issue revenue bonds and other forms of indebtedness to the extent, and on the terms, provided by the Act;

2.5.9 apply for, accept, and receive all licenses, permits, grants, loans or other aids from any federal, state, or local public agency;

2.5.10 submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program;

2.5.11 adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority ("Operating Rules and Regulations"); and

2.6 **Exercise of Powers**. In accordance with Section 6509 of the Act, the Authority's powers shall be subject to the restrictions upon the manner of exercising such powers, pertaining to the city of ________.

ARTICLE 3
AUTHORITY PARTICIPATION

3.1 **Addition of Parties**. Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or such county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption, by an affirmative vote of the Board satisfying the requirements described in Section 4.8.1, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership payment, if any; and (e) satisfaction of any conditions established by the Board.

3.2 **Continuing Participation**. The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Sections 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4

GOVERNANCE AND INTERNAL ORGANIZATION

4.1 **Board of Directors**. The governing body of the Authority shall be a Board of Directors ("Board") consisting of two directors for each Party and appointed in accordance with Section 4.2.

4.2 **Appointment and Removal of Directors**. The Directors shall be appointed and may be removed as follows:

4.2.1 The governing body of each Party shall appoint and designate in writing two regular Directors who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party may also appoint and designate in writing one alternate Director for each regular Director who may vote on matters when the regular Director is absent from a Board meeting. One person appointed and designated as a Director shall normally be the City Manager/Administrator or his or her delegate.

4.2.2 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.11, shall specify the bases for and process associated with the removal of an individual Director for cause. The Operating Rules and Regulations may also describe disciplinary action that may be taken against an individual Director for action that is harmful to the orderly and effective operation of the Authority or the Board. Notwithstanding the foregoing, no Party shall be deprived of its right to seat a Director on the Board and any such Party for which its Director and/or alternate Director has been removed may appoint a replacement.

4.3 **Terms Of Office**. Each Director shall serve at the pleasure of the governing body of the Party that the Director represents, and may be removed as Director by such governing body at any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.

4.4 **Quorum**. A majority of the Directors shall constitute a quorum, except that less than a quorum may adjourn from time to time in accordance with law.

4.5 **Powers and Function of the Board**. The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law.

4.6 **Executive Committee**. The Board may establish an executive committee consisting of a smaller number of Directors. The Board may delegate to the executive committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain essential functions, as described in the Operating Rules and Regulations.

4.7 **Directors' Compensation**. Compensation for work performed by Directors for activities of the Authority shall be borne by the Party that appointed the Director. However, the Board, by resolution, may adopt a policy relating to the reimbursement of expenses incurred by Directors.

4.8 **Board Voting**.

4.8.1 To be effective, a vote of the Board shall require the affirmative vote of all Directors present and voting. The exception would be that the Board may take action upon a simple majority vote on matters designated by the Directors representing such majority that urgent action is needed to fulfill the Authority's obligations under this or other agreements. Additionally, for actions involving any particular program, and not affecting the rights of any non-participant in such program, action may be taken upon unanimous vote of the members representing the participants (unless otherwise provided for in the Program Agreement for such program).

4.9 **<u>Meetings and Special Meetings of the Board</u>**. The Board shall hold at least four regular meetings per year, and by action of the Board may provide for the holding of regular or special meetings at more frequent intervals. The date upon which, and the hour and place at which, each such regular meeting shall be held shall be fixed by action of the Board. Special meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956. Directors may participate in all meetings telephonically, with full voting rights, pursuant to applicable statutes and regulations. All meetings of the Board shall be called, held, noticed, and conducted subject to the provisions of the Ralph M. Brown Act (California Government Code Section 54950 *et seq*.).

4.10 **<u>Selection of Board Officers</u>**.

4.10.1 **Chair and Vice Chair**. The Directors shall select, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The term of office of the Chair and Vice Chair shall continue for one year, but there shall be no limit as to the number of terms held by either or both the Chair and Vice Chair. The office of either or both the Chair and Vice Chair shall be declared vacant and a new selection required if: (a) the person serving dies, resigns, or the Party that the person represents removes the person as its representative on the Board or (b) the Party that he or she represents withdraws from the Authority pursuant to any of the provisions herein.

4.10.2 **Secretary**. The Board shall appoint and designate from time to time a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.

4.10.3 **Treasurer and Auditor**. The Board shall appoint and designate from time to time a qualified person to act as the Treasurer and a qualified person to act as the Auditor, either or both of whom need not be members of the Board. If the Board so designates, and in accordance with provisions of applicable law, a qualified person may hold both the office of Treasurer and the office of Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depositary of the Authority and have custody of all of the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to file with the Authority an official bond in an amount to be fixed by the Board, and if so requested the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide from time to time. The duties and obligations of the Treasurer are further specified in Article 6.

4.11 **Management.** The Board shall appoint a General Manager who will have general responsibility for operations of the Authority, consistent with the policies established by the Board. The General Manager may be an employee of the Authority, an individual under contract to the Authority, a corporation or other entity duly organized under law, or any other person designated by the Board.

ARTICLE 5
IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 **Preliminary Implementation of the CCA Program**.

5.1.1 **Enabling Ordinance**. If a Party has not otherwise done so prior to its execution of this Agreement, the Party shall, as soon after the Effective Date as reasonably practicable, cause to be adopted an ordinance in accordance with Public Utilities Code Section 366.2(c)(10) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.

5.1.2 **Implementation Plan**. The Authority shall cause to be filed an Implementation Plan with the California Public Utilities Commission as soon after the Effective Date as reasonably practicable.

5.1.3 **Other Activity**. The Authority shall cause to be performed such other activities relating to the CCA Program in order to prepare the CCA Program for actual implementation, which shall be evidenced by the execution and effectiveness of Program Agreement 1.

5.2 **Authority Documents**. The Parties acknowledge and agree that the affairs of the Authority will be implemented through various documents duly adopted by the Board through Board resolution, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies ("Authority Documents"). The Parties agree to abide by and to comply with the terms and conditions of all such Authority Documents that may hereafter be adopted by the Board, subject to the Parties' right to withdraw from the Authority as described in Article 7.

ARTICLE 6
FINANCIAL PROVISIONS

6.1 **Fiscal Year**. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 **Depositary**.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly, and separately, accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times. The Board shall contract with a certified public accountant or public accountant to make an annual audit of the accounts and records of the Authority, which shall be conducted in accordance with the requirements of Section 6505 of the Act.

6.2.3 All expenditures within the designations and limitations of the applicable approved budget shall be made upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the approval and written order of the Board.

6.3 **Budget and Recovery of Costs**.

6.3.1 **Budget**. The Board shall cause to be developed an initial draft budget for the Authority and shall submit such draft budget to the Parties in a form and in accordance with a schedule reasonably established by the Board. Upon review and any necessary revision to such initial draft budget and subsequent draft budgets, the Board shall adopt a final budget as soon as reasonably practicable. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses.

6.3.2 Initial Costs. Initial CCA costs include all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as any required accounting, administrative and legal services in support of the Authority's initial activities or in support of the finalization of Program Agreement 1. As further described in Section 6.3.6, initial costs shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

6.3.3 CCA Program Costs. The Parties desire that, to the extent reasonably practicable, all costs incurred by the Authority that are directly or indirectly attributable to the provision of electric services under the CCA Program, including the establishment and maintenance of various reserve and performance funds, shall be recovered through charges associated with such electric services. The Parties intend that all such charges will first be applied upon the commencement of electric services provided under the CCA Program.

6.3.4 General Costs. Costs that are not directly or indirectly attributable to the provision of electric services under the CCA Program, as determined by the Board, shall be defined as general costs, it being understood that such general costs, in the aggregate, are intended to be fairly minor in relation to the overall costs of the Authority. As further described in Section 6.3.6, general costs shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

6.3.5 Special Program Costs. It is anticipated that from time to time the Authority and the Parties may participate in certain additional special programs. As the Parties contemplate will be done with respect to Program Agreement 1, the terms and conditions associated with these special programs, and the costs associated therewith, shall be set forth in a separate agreement.

6.3.6 Recovery of Costs. Prior to the execution of Program Agreement 1 by the Authority, the Authority shall not incur initial and general costs in excess of $______ without specific authorization of the Board. The Authority shall issue an invoice to each Party for costs under this Agreement, and each Party shall provide payment to the Authority, in accordance with policies and procedures established by the Board. Upon request of any Party, the Authority shall produce and allow the inspection of all documents relating to the computation of the expenses attributable to the Parties. If the Party does not agree with the amount listed on the invoice it must still make full payment, subject to dispute. Further policies and procedures relating to disputed bills shall be established by the Board. If the amounts in dispute cannot be resolved to the satisfaction of the disputing Party, the dispute shall be resolved pursuant to Section 8.1.

6.3.7 Debt Limitation. The Parties' liability for payments under this Agreement is contingent on the approval and allocation of funds in any fiscal year hereunder, in accordance with the debt limitation set forth in the California Constitution.

ARTICLE 7
WITHDRAWAL AND TERMINATION

7.1 <u>**Withdrawal**</u>.

7.1.1 General.

7.1.1.1 Prior to a Party's execution of Program Agreement 1, such Party may withdraw its membership in the Authority by giving no less than 1 months advance written notice of its election to do so, which notice shall be given to the Authority and each Party.

7.1.1.2 Subsequent to a Party's execution of Program Agreement 1, such Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year (July 1), by giving no less than 6 months advance written notice of its election to do so, which notice shall be given to the Authority and each Party, and upon such other conditions as may be prescribed in Program Agreement 1.

7.1.2 Continuing Liability; Further Assurances. A Party that withdraws its membership in the Authority may be subject to certain continuing liability, as described in Section 7.3. The withdrawing Party agrees to execute and deliver all further instruments and documents, and take any further action, that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority.

7.2 <u>**Involuntary Termination of a Party**</u>.

7.2.1 Failure to Execute Program Agreement 1. This Agreement shall be deemed terminated with respect to a Party if such Party has not executed Program Agreement 1 within 90 days of the Authority's written notice to all Parties that the Authority has executed Program Agreement 1.

7.2.2 Material Non-Compliance. This Agreement may be terminated with respect to a Party for material non-compliance with provisions of this

Agreement, the Operating Rules and Regulations, or the Authority Documents upon a unanimous vote of the Board, excluding the Directors of the Party subject to possible termination. Prior to any vote to terminate this Agreement with respect to a Party, written notice of the proposed termination and the reason(s) for such termination shall be presented at a regular Board meeting with opportunity for discussion. The Party subject to possible termination shall have the opportunity at the next regular Board meeting to respond to any reasons and allegations that may be cited as a basis for termination prior to a vote regarding termination. A Party that has had its membership in the Authority terminated may be subject to certain continuing liability, as described in Section 7.3.

7.3 **Continuing Liability; Refund**. Upon any withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liability arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any such claim, demand, damage, or liability arising after the date of the Party's withdrawal or involuntary termination. In addition, such Party shall also be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreement(s) relating to such program. The Authority may withhold funds otherwise owing to the Party or may require of the Party sufficient funds on deposit with the Authority, as reasonably determined by the Authority, to cover the Party's contingent liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required above shall be returned to the Party.

7.4 **Mutual Termination**. This Agreement may be terminated by mutual agreement of all Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.

7.5 **Disposition of Property Upon Termination of Authority**. Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred under this Agreement and under any program documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8
MISCELLANEOUS PROVISIONS

8.1 **<u>Dispute Resolution</u>**. The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Should such efforts to settle a dispute, after reasonable efforts, fail, said dispute shall be settled by binding arbitration in accordance with policies and procedures established by the Board.

8.2 **<u>Liability of Directors, Officers, and Employees</u>**. The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall indemnify and hold harmless the individual Directors, officers, and employees for any action taken lawfully and in good faith on behalf of the Authority. Nothing in this section shall be construed to limit the defenses available under the law, to the Parties the Authority, or its Directors, officers, or employees.

8.3 **<u>Amendment of this Agreement</u>**. This Agreement may be amended by an affirmative vote of all Directors present and voting.

8.4 **<u>Assignment</u>**. Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.4 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.4 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.

8.5 **<u>Severability</u>**. If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provisions shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

8.6 **<u>Further Assurances</u>**. Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.

8.7 **<u>Execution by Counterparts</u>**. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.8 **<u>Parties to be Served Notice</u>**. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 48 hours after the deposit thereof if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties.

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Power Authority.

By: ____________________________________

Name: __________________________________

Title: ____________________________________

Date: __________________

Party: ___________________________________

Exhibit A
To the
Joint Powers Agreement
East Bay Power Authority

- Definitions -

"AB 117" means Assembly Bill 117 (Stat. 2002, ch. 838, principally codified at Public Utilities Code Section 366.2), which created the CCA option.

"Act" means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.)

"Agreement" means this Joint Powers Agreement.

"Authority" means the East Bay Power Authority, established by this Agreement.

"Authority Document(s)" means document(s) duly adopted by the Board through Board resolution and made effective as to the implementation of the Authority, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies.

"Board" means the Board of Directors of the Authority.

"CCA" or "Community Choice Aggregation" means an electric service option available to cities and counties pursuant to AB 117.

"CCA Program" means the Authority's program relating to CCA that is principally described in Sections 2.4 and 5.1.

"Director" means a member of the Board of Directors representing a Party.

"Effective Date" means the date on which this Agreement shall become effective and the East Bay Power Authority shall exist as a separate public agency, as further described in Section 2.1.

"Implementation Plan" means the plan generally described in Section 5.1.2 of this Agreement that is required under AB 117 to be filed with the California

Public Utilities Commission for the purpose of describing a proposed CCA Program.

"Initial Participants" means, for the purpose of this Agreement, the Cities of Berkeley, Emeryville and Oakland.

"Operating Rules and Regulations" means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.

"Parties" means, collectively, the signatories to this Agreement that, as necessary, have satisfied the conditions in Section 3.2 such that they are considered members of the Authority.

"Party" means, singularly, a signatory to this Agreement that, as necessary, has satisfied the conditions in Section 3.2 such that it is considered a member of the Authority.

"Program Agreement 1" means the agreement among the Authority and certain or all Parties that the Parties contemplate will be entered into as soon after the Effective Date as reasonably practicable and that will describe the material terms and conditions of the CCA Program and determine which of the Parties will actually implement the CCA Program.

Exhibit B
To the
Joint Powers Agreement
East Bay Power Authority

- Parties -

This Exhibit B is effective as of _______________, 2007.

The Parties include the following:

[City of Berkeley]
[City of Emeryville]
[City of Oakland]

PROPOSED PRINCIPLES FOR AN AGGREGATION PROGRAM AGREEMENT

EBPA Authority: The Cities ("CCA Participants") executing the Aggregation Program Agreement will grant exclusive authority to the EBPA to act as the Community Choice Aggregator under AB 117 and decisions of the California Public Utilities Commission within their respective jurisdictions. Concurrent with the execution of the Agreement or as soon thereafter as reasonably practicable, each CCA Participant will adopt an ordinance in accordance with Public Utilities Code Section 366.2, subdivision (c), paragraph 10, which shall specify that the CCA Participant elects to implement a community choice aggregation program by and through its participation in the EBPA. As the Community Choice Aggregator, the EBPA will adopt the Implementation Plan required under AB 117; register with the CPUC; execute the required service agreements with the Utility Distribution Company; comply with other registration or reporting provisions required of a Community Choice Aggregator; and will have direct interaction with end-use customers.

Project Agreements: The Members shall not be bound or otherwise obligated to support the EBPA's acquisition, purchase, lease or construction of generation or transmission facilities, or the execution of contracts with terms in excess of ten years, except to the extent specifically provided for in a Project Agreement approved by the Members.

Local Regulatory Authority: The Board of Directors of EBPA will be the local regulatory authority with respect to services provided pursuant to the Aggregation Program Agreement. The Board of Directors will establish the rates, terms and conditions for such service. Additionally, the Board of Directors will review and approve the EBPA's budgets, implementation plans, contracts, and standards and procedures for providing aggregated electric services.

Notice of Rate Changes: The EBPA 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 EBPA rates are to 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 may provide comment on the proposed rate changes. Notice of rate changes will be published at least once in a newspaper of general circulation in the county within ten days after submitting the application. Such notice will state that a copy of said application and related exhibits may be examined at the offices of the EBPA as are specified in the notice, and shall state the locations of such offices. Within forty-five days after submitting an application to increase any rate of charge, the EBPA will furnish to its customers affected by the proposed increase notice of its application either by mailing such notice postage prepaid to such customers or by including such notice with the regular bill for charges transmitted to such customers. The notice will state the amount of the proposed increase expressed in both dollar and percentage terms, a brief statement of the reasons the increase is required or sought, and the mailing address of the EBPA 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.

Annual Resource Plan: The Board of Directors will review and approve an annual resource plan for the purpose of implementing the Aggregation Program Agreement. The annual resource plan will include, but is not to be limited to, information relative to load demand forecasts, projected resource availability and needs, adherence to resource adequacy and renewable portfolio requirements, supplemental power requirements, estimated excess power sales, annual cost for providing the services under the Aggregation Program Agreement, scheduling plans and additional information as related to the management of resources under the Agreement.

Long Term Resource Plan: The Board of Directors will review and approve a long term resource plan on a biannual basis. The long-term resource plan will include, but is not to be limited to, information relative to 10-year demand and supply forecasts, adherence to resource adequacy and renewable portfolio requirements and objectives, energy efficiency and demand-side management programs, and additional information as related to the long-term plan for meeting the resource needs for the CCA Program.

Operations: EBPA will provide, or cause to be provided, the necessary administrative, technical, financial, and management services to effectuate the resource planning and operations activities required under the Agreement for the CCA program. Consistent with the annual resource plan, the long term resource plan, and separate Project Agreements executed between the EBPA and its Members, the EBPA will procure, acquire, or construct and own electric resources to meet the CCA Program' anticipated demands. It is anticipated that such electric resources shall consist of a mix of short and long term electric power contract purchases, and the development, construction and operation of generating facilities to provide reliable, cost-effective, cost-based, and environmentally responsible electricity for the CCA Customers served by the EBPA. It is further anticipated that the resource plan will significantly exceed the renewable portfolio standards applicable to retail sellers of electricity within California. The EBPA will also provide, or cause to be provided, all CCA customer account management services, communications, customer services and marketing plans or materials related to the CCA Program.

Customer Notifications: The EBPA will provide, or cause to be provided, all customer opt-out notices required by AB 117, CPUC Decisions and the adopted Implementation Plan. The opt-out notice shall inform the customer of both of the following: (1) that they are to be automatically enrolled and that the customer has the right to opt out of the community choice aggregator without penalty; and (2) the terms and conditions of the services offered. The notifications shall also include a mechanism by which ratepayers may opt out of community choice aggregated service. The EBPA shall provide such customer notices at least twice within two calendar months prior to automatic enrollment and twice within two billing cycles following automatic enrollment, as required by PUC Code Section 366.2 section (C) paragraph 13 and in accordance with the notification provisions described in the EPBA's approved Implementation Plan. The Board of Directors will approve the content of all such notices in advance.

Auto-Enrollment: Eligible electric consumers will be automatically enrolled in the CCA Program as a CCA Customer following the acceptance of the Implementation Plan by the CPUC, the EBPA's execution of service agreements with the Utility Distribution Company, and completion of the required Customer Notifications. Eligible electric consumers will be automatically enrolled consistent with the procedures set forth by the CPUC and the EBPA's approved Implementation Plan. The EBPA will notify the Utility Distribution Company of the CPUC's acceptance of the Implementation Plan and the CCA Program service start date.

Establishment of Annual Rates: Costs incurred by the EBPA in the performance of the Agreement will be recovered through rates applicable to CCA Customers. As part of the review and approval of the annual resource plan, the Board of Directors will establish rates for end-use customers for recovery of all costs incurred by the EBPA that are attributable to the provision of electric services under the CCA Program, including the establishment and maintenance of various reserve and performance funds. The rates for end-use customers will be based on principles agreed upon by the Board of Directors. Unless unanimously agreed upon by the Board of Directors, all rates within the various customer classifications will be identical for customers served by the EBPA within each of the CCA Participant's respective jurisdictions. The EBPA will provide electric services on a non-discriminatory basis to the CCA Customers; provided, however, that prices and other terms may vary in accordance with reasonably established classes of customers (e.g., residential, commercial, municipal, and industrial) and service options.

Periodic Rate Changes: Rates may be adjusted by the Board of Directors as may be required to maintain established levels of reserves and operating funds.

Billing: In accordance with procedures reviewed and approved by the Board of Directors, the EPBA will cause the Utility Distribution Company to bill each CCA Customer for charges owed by the CCA Customer under the CCA Program. The EBPA shall establish by Board resolution rules describing the CCA Customers' obligations to pay for charges under the CCA Program, including the rights of CCA Customers to dispute a bill.

Net Unavoidable Costs: Unless otherwise expressly agreed, costs associated with electric resources procured or acquired by the EPBA will be recoverable through rates from all CCA Customers existing as of the effective data of the commitment to such purchases and acquisitions, and from all future CCA Customers reasonably forecasted to be served by such electric resources. The net unavoidable costs of such electric resources over a reasonable forecast period, as determined by the Board of Directors, shall not be avoided by a CCA Participant's withdrawal from this Agreement.

Annual Review and Disbursement of Benefits: As soon as reasonably practicable after the annual audit of costs, EBPA will review actual costs incurred in the performance of CCA services and compare such costs to revenues received from customers. If, on the basis of this review, such revenues exceed actual costs and pre-established reserve levels, EBPA will disburse a check to individual CCA Participants reflecting their respective share of the difference. Such shares shall be determined pro rata based on the kWh provided by the EBPA to CCA customers within each CCA Participant's jurisdictional boundaries during the prior fiscal year.

Participant Withdrawal: A CCA Participant may withdraw from the Aggregation Program Agreement upon written notice to EBPA and other CCA Participants. Such withdrawal will result in all customers within the withdrawing CCA Participant's jurisdiction being returned to bundled electric service provided by the Utility Distribution Company. The withdrawing CCA Participant will be responsible for all costs reasonably attributable to the return of customers to bundled service, including specifically (a) any and all costs imposed on EBPA by the Utility Distribution Company and (b) the withdrawing CCA Participant's relative share of the net unavoidable costs associated with the EBPA power purchase obligations existing as of the date of the withdrawing CCA Participant's notice.

Liability of the Authority and CCA Participants: Unless otherwise expressly set forth in a third-party agreement approved by the Board, the CCA Participants shall not be jointly and severally liable for obligations under third-party agreements, it being the intent of the EBPA and the CCA Participants that liabilities under third-party agreements shall be incurred directly by the EBPA with any resulting cost responsibility being borne by the CCA Participants in accordance with principles set forth in this Agreement and any Board resolution implementing the principles set forth in this Agreement. No EBPA Board member, officer, or employee will be responsible for any act or omission by another Board member, officer, or employee. The EBPA shall indemnify and hold harmless the individual EBPA Board members, officers and employees for any action taken lawfully and in good faith pursuant to this Agreement.

Appendix H-2: Proposed Renewable Generation Projects

The California ISO Controlled Grid Generation Queue
As of: April 18, 2007

Interconnection Request Receive Date	Application Status	Type	Fuel	Summer	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study (SIS)	Facility Study (FAS)	Interconnection Agreement Status
6/10/2005	Active	ST	B	6.8	Humboldt	CA	PGE	Rio Dell Substation 60 KV	1/1/2006	1/1/2006	Waived	Complete	Waived	
4/28/2005	Active	ST	B	10.5	Merced	CA	PGE	PG&E Merced #1 70 kV circuit	7/1/2006	7/1/2006	NA	Complete	Complete	Tendered
4/28/2005	Active	ST	B	10.5	Madera	CA	PGE	Le Grand-Chowcilla 115 kV	12/31/2005	12/31/2006	NA	Complete	Complete	Tendered
5/2/2006	Active	ST	B	27	San Diego	CA	SDGE	Border Substation 69 kV	12/1/2008	12/1/2008	Complete	In Progress		
6/23/2006	Active	ST	B	20	Kern	CA	PGE	Tap of Chevron 70kv tran line	8/31/2009	8/13/2009	NA	Complete		
Biomass Subtotal			**B Total**	**75**										
7/9/2004	Active	ST	G	10	Curchill	NV	SCE	Bishop Control Sub	7/14/1988	5/31/2006	NA	Complete	Complete	
9/13/2005	Active	ST	G	55	Lake	CA	PGE	Geysers #17 - Fulton 230 kV Line	9/1/2006	9/1/2006	Waived	Complete	In Progress	Executed
1/25/2005	Active	ST	G	62	Mineral	NV	SCE	Dixie-Valley-Oxbow 220	10/7/2007	10/7/2007	NA	Complete	In Progress	
3/5/2007	Active	ST	G	35	Sonoma	CA	PGE	Geysers #3 – Cloverdale 115 kV Line	1/1/2010	1/1/2010	Tendered			
3/14/2007	Active	ST	G	50	Sonoma	CA	PGE	Geysers-Fulton 230kV transmission line	1/1/2011	1/1/2011				
3/6/2007	Active	ST	G	150	Mineral	NV	SCE	Bishop, CA Control Sub	8/1/2011					
Geothermal Subtotal			**G Total**	**362**										
3/30/2005	Active	Other	S	850	San Bernadino	CA	SCE	Pisgah 230 kV Substation	1/31/2008	1/31/2008	Waived	Complete	Tendered	
11/16/2006	Active	PV	S	150	Riverside	CA	SCE	Eagle Mountain Substation	12/1/2008	12/1/2008	In Progress			
12/2/2006	Active	ST	S	220	San Bernardino	CA	SCE	Kramer	1/1/2009	1/1/2009	In Progress			
5/26/2006	Active	Other	S	635	San Bernardino	CA	SCE	Mohave 500 kV Switchyard	12/31/2009	12/31/2009	In Progress			
11/6/2006	Active	ST	S	80	San Bernardino	CA	SCE	Kramer Substation	12/31/2009	12/31/2009	Tendered			
11/6/2006	Active	ST	S	80	San Bernardino	CA	SCE	Kramer Substation	12/31/2009	12/31/2009	Tendered			
11/6/2006	Active	ST	S	320	San Bernardino	CA	SCE	Kramer Substation	12/31/2009	12/31/2009	Tendered			
11/28/2006	Active	ST	S	500	Kern	CA	SCE	Kramer 230 kV Substion	12/31/2009	12/31/2009	Tendered			
8/31/2005	Active	Other	S	300	Imperial	CA	SDGE	Imperial Valley Substation	12/31/2009	12/31/2009	Waived	Complete	In Progress	
11/16/2006	Active	PV	S	400	Riverside	CA	SCE	Eagle Mountain Substation	2/1/2010	2/1/2010	In Progress			
9/25/2006	Active	ST	S	100	San Bernardino	CA	SCE	Mountain Pass Substation	6/30/2010	6/30/2010	Complete	In Progress		
11/16/2006	Active	ST	S	114	San Bernardino	CA	SCE	Wheaton 115kV bus	6/30/2010	6/30/2010	In Progress			
8/22/2006	Active	Other	S	300	San Bernardino	CA	SCE	Kramer Substation	8/1/2010	8/1/2010	In Progress			
9/13/2006	Active	Other	S	565	San Bernardino	CA	SCE	Mohave Generating Station	12/31/2010	12/31/2010	Tendered			
1/9/2007	Active	PV	S	300	San Bernardino	CA	SCE	Mountain Pass Substation	12/31/2010	12/31/2010	Tendered			
1/23/2007	Active	PV	S	300	San Luis Obispo	CA	PGE	Morrow Bay-Midway 230kV line	12/31/2010	12/31/2010	Tendered			
2/15/2007	Active	ST	S	300	Riverside	CA	SCE	Eagle Mountain 230kV Substation	12/31/2010	12/31/2010				
3/5/2007	Active	PV	S	500	Kern	CA	SCE	Tehachapi Conceptual Substation	12/31/2010	12/31/2010				
3/19/2007	Active	ST	S	500	Riverside	CA	SCE	Julian Hinds 230kV Substation	12/31/2010	12/31/2010				
6/14/2006	Active	Other	S	550	San Bernardino	CA	SCE	Pisgah Substation	3/1/2011	3/1/2011	Tendered			
8/9/2006	Active	Other	S	1200	San Bernardino	CA	SCE	Mojave 500 kV Switchyard	3/1/2011	3/1/2011	Tendered			
8/22/2006	Active	Other	S	600	Imperial	CA	SDGE	Imperial Valley Substation	3/1/2011	3/1/2011	Waived	In Progress		
1/16/2007	Active	ST	S	500	San Bernardino	CA	SCE	Pisgah 230kV Substation	6/30/2011	6/30/2011				
2/2/2007	Active	ST	S	500	Imperial	CA	SDGE	Imperial Valley 500kV bus	12/31/2011	12/31/2011				
2/2/2007	Active	ST	S	500	Kern	CA	SCE	Substation 5 (aka Whirlwind)	12/31/2011	12/31/2011				
6/14/2006	Active	Other	S	1400	San Bernardino	CA	SCE	Pisgah Substation	3/1/2013	3/1/2013	Tendered			
4/5/2007	Active	ST	S	190	San Luis Obispo	CA	PGE	Loop 230kV lines newar Carrizo Plain Substation	12/31/2010	12/10/3110				
Solar Subtotal			**S Total**	**11954**										

The California ISO Controlled Grid Generation Queue
As of: April 18, 2007

Interconnection Request Receive Date	Application Status	Type	Fuel	Summer	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study (SIS)	Facility Study (FAS)	Interconnection Agreement Status
6/4/2003	Complete	WT	W	46	San Diego	CA	SDGE	Crestwood	12/31/2005	10/1/2005	NA	Complete	Complete	Executed
10/3/2003	Active	WT	W	37.55	Byron	CA	PGE	Windmaster/Buena Vista Sub	7/1/2004	1/27/2006	NA	n/a	n/a	Executed
12/16/2002	Active	WT	W	150	Solano	CA	PGE	New Birds Lndng Sw Stn near Contra Costa PP Sub	10/31/2005	3/30/2006	NA	Complete	Complete	GSFA Executed
3/8/2004	Active	WT	W	201	Lake & Sonoma	CA	PGE	Collector Substation at Geysers #17 & Fulton 230 kV line	12/1/2006	12/1/2006	NA	Complete	Complete	Tendered
12/14/2004	Active	WT	W	100.5	Riverside	CA	SCE	Devers Substation	12/1/2006	12/1/2006	NA	Complete	In Progress	
1/30/2004	Active	WT	W	150	Solano	CA	PGE	High Winds/Contra Costa PP	12/31/2006	12/31/2006	NA	Complete	Complete	GSFA Executed
11/18/2003	Active	WT	W	38	Solano	CA	PGE	New Birds Lndng Sw Sta near Contra Costa PP Sub	6/30/2005	3/1/2007	NA	Complete	Complete	GSFA Executed
9/30/1998	Active	WT	W	16.5	Riverside	CA	SCE	Devers-Garnet 115 kV line (Tap)	3/1/1999	3/31/2007	NA	Complete	Complete	
2/5/2004	Active	WT	W	117	San Diego	CA	SDGE	Crestwood	6/6/2005	6/1/2007	NA	In Progess		
5/12/2004	Active	WT	W	201	San Diego	CA	SDGE	Boulevard - Crestwood 69-kV transmission line	9/1/2007	9/1/2007	NA	In Progess		
7/12/2005	Active	WT	W	102	Shasta	CA	PGE	230kV line btn Pit#3 & Round Mtn	12/15/2007	12/15/2007	Complete	Complete	Re-study Tendered	
12/28/2005	Active	WT	W	120	Kern	CA	SCE	Segment 3 230 Collector Loop Tehachapi	12/31/2007	12/31/2007	In Progress			
4/5/2006	Active	WT	W	120	Kern	CA	SCE	Vincent Substation through Sagebrush 230 kV line	12/31/2007	12/31/2007	In Progress			
12/31/2002	Active	WT	W	50	San Bernardino	CA	SCE	Mountain Pass	9/1/2004	12/31/2007	NA	Complete	Complete	
1/20/2006	Active	WT	W	33.1	Kern	CA	SCE	Vincent Substation	1/1/2008	1/1/2008	In Progress			
1/20/2006	Active	WT	W	34	Kern	CA	SCE	Canwind Substation	1/1/2008	1/1/2008	In Progress			
2/12/2004	Active	WT	W	36	San Diego	CA	SDGE	Crestwood	4/1/2006	1/1/2008	NA	In Progress		
10/14/2002	Active	WT	W	63	San Bernardino	CA	SCE	Mountain Pass Substation	12/1/2004	3/1/2008	NA	Complete	Complete	
12/15/2006	Active	WT	W	100	Kern	CA	SCE	66kV Antelope-Neenach-Bailey line	5/30/2008	5/30/2008	In Progress			
11/22/2006	Active	WT	W	100	Kern	CA	SCE	66kV Antelope-Neenach-Bailey line	5/30/2008	5/30/2008	Tendered			
12/15/2006	Active	WT	W	100	Kern	CA	SCE	66kV Rosamond-Antelope line	5/30/2008	5/30/2008	Tendered			
12/15/2006	Active	WT	W	100	Kern	CA	SCE	66kV Rosamond-Delsur line	5/30/2008	5/30/2008	Tendered			
5/1/2006	Active	WT	W	160	San Diego	CA	SDGE	500 kV Imperial Valley-Miguel trans line	6/30/2008	6/30/2008	Complete	In Progress		
6/29/2006	Active	WT	W	150	San Bernardino	CA	SCE	Victor 230 kV	7/1/2008	7/1/2008	In Progress			
6/29/2006	Active	WT	W	150	San Bernardino	CA	SCE	Pisgah-Lugo 230kV Trans Line	7/1/2008	7/1/2008	In Progress			
6/29/2006	Active	WT	W	50	San Bernardino	CA	SCE	Pisgah-Lugo Sub 230kV	7/1/2008	7/1/2008	In Progress			
10/10/2006	Active	WT	W	60	San Bernardino	CA	SCE	Lugo-Pisgah 230kV Transmission Line	9/15/2008	9/15/2008	In Progress			
2/21/2007	Active	WT	W	500	Kern	CA	SCE	SCE Proposed Whirlwind Substation	9/30/2008	9/30/2008				
3/11/2003	Active	WT	W	120	Santa Barbara	CA	PGE	Cabrillo	6/1/2006	10/1/2008	NA	Complete	Complete	GSFA Executed
6/28/2006	Active	WT	W	300	San Diego	CA	SDGE	500 kV Imperial Valley-Miguel trans line	10/31/2008	10/31/2008	Complete	In Progress		

The California ISO Controlled Grid Generation Queue
As of: April 18, 2007

Interconnection Request Receive Date	Application Status	Type	Fuel	Summer	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study (SIS)	Facility Study (FAS)	Interconnection Agreement Status
4/19/2006	Active	WT	W	210	Monterey	CA	PGE	PG&E Coburn 230 kV Sub	11/30/2008	11/30/2008	Complete	In Progress		
2/16/2007	Active	WT	W	30	Riverside	CA	SCE	Devers-Venwind 115kV line	12/1/2008	12/1/2008				
9/16/2005	Active	WT	W	60	San Bernardino	CA	SCE	Lugo-Pisgah No. 2 230 kV tran line	12/31/2008	12/31/2008	Complete	Tendered		
3/1/2006	Active	WT	W	220	Kern	CA	SCE	Tehachapi Conceptual Substation #1	12/31/2008	12/31/2008	In Progress			
3/1/2006	Active	WT	W	180	Kern	CA	SCE	Tehachapi Conceptual Substation #2	12/31/2008	12/31/2008	In Progress			
8/19/2003	Active	WT	W	300	Kern	CA	SCE	Antelope	12/31/2006	12/31/2008	NA	Complete	Complete	
11/11/2004	Active	WT	W	200	Solano	CA	PGE	New Birds Lndng Sw Sta near Contra Costa PP Sub	12/31/2008	12/31/2008	NA	Complete	Complete	Executed
6/6/2005	Active	WT	W	250	Kern	CA	SCE	Antelope Sub	12/31/2007	12/31/2008	Waived	In Progress		
10/23/2006	Active	WT	W	150	Riverside	CA	SCE	Devers-Vista 230kV #1	12/31/2008	12/31/2008	Waived	In Progress		
12/5/2006	Active	WT	W	201	San Bernardino	CA	SCE	Lugo-Pisgah 230 kV circuit #1	3/1/2009	3/1/2009				
6/29/2006	Active	WT	W	30	Solano	CA	PGE	Birds Landing	4/1/2009	4/1/2009	Complete	In Progress		
12/6/2006	Active	WT	W	400	La Rumorosa, Baja CA	Mexico	SDGE	500kV Imperial Valley-Miguel transmission line	6/1/2009	6/1/2009	In Progress			
7/7/2006	Active	WT	W	70	Humboldt	CA	PGE	Bridgeville 115kV Substation	10/30/2009	10/30/2009	Complete	In Progress		
3/5/2007	Active	WT	W	300	La Rumorosa, Baja CA	Mexico	SDGE	500kV Imperial Valley-Miguel transmission line	11/1/2009	11/1/2009				
5/24/2005	Active	WT	W	51	Kern	CA	SCE	Proposed "New" Dutchwind Substation	6/1/2006	12/15/2009	Complete	In Progress		
11/22/2005	Active	WT	W	400	Kern	CA	SCE	Cottownwind Substation	12/31/2009	12/31/2009	In Progress			
3/1/2006	Active	WT	W	550	Kern	CA	SCE	Tehachapi Conceptual Substation #1	12/31/2009	12/31/2009	In Progress			
3/1/2006	Active	WT	W	600	Kern	CA	SCE	Tehachapi Conceptual Substation #1	12/31/2009	12/31/2009	In Progress			
3/1/2006	Active	WT	W	160	Kern	CA	SCE	Tehachapi Conceptual Substation #5	12/31/2009	12/31/2009	In Progress			
11/22/2006	Active	WT	W	105	Santa Barbara	CA	PG&E	No. 1 & No. 2 Mesa-Divide 115kV Lines	12/31/2009	12/31/2009	In Progress			
4/12/2004	Active	WT	W	201	Kern	CA	SCE	Monolith Substation	12/31/2007	12/31/2009	NA	Complete	In Progress	
7/19/2004	Active	WT	W	300	Kern	CA	SCE	Monolith Substation	7/1/2007	12/31/2009	NA	Complete	In Progress	
9/27/2006	Active	WT	W	297	Kern	CA	SCE	SCE 230kV Conceptual Substation #2	12/31/2009	12/31/2009	Tendered			
11/16/2006	Active	WT	W	362	Kern	CA	SCE	SCE Highwind Sub #2 (proposed) 230 kV	12/31/2009	12/31/2009	Tendered			
2/22/2006	Active	WT	W	51	Kern	CA	SCE	Segment 3 of Antelope Transmission Project	3/31/2010	3/31/2010	Waived	In Progress		
1/12/2007	Active	WT	W	1000	La Rumorosa, Baja CA	Mexico	SDGE	Imperial Valley 230kV switchyard	10/1/2010	10/1/2010	Tendered			
8/8/2006	Active	WT	W	500	Kern	CA	SCE	Tehachapi Conceptual Substation #1	12/31/2010	12/31/2010	In Progress			
6/9/2006	Active	WT	W	128	Solano	CA	PGE	Lambie-Contra Costa 230 kV	3/1/2011	3/1/2011	Complete	In Progress		
8/31/2006	Active	WT	W	1500	Clark	NV	SCE	Eldorado Substation	12/31/2011	12/31/2011	In Progress			
2/27/2007	Active	WT	W	200	Contra Costa	CA	PGE	Lakeville-Sobrante 230kV line	12/31/2011	12/31/2011	Tendered			
2/27/2007	Active	WT	W	200	Santa Clara	CA	PGE	Los Banos 230kV bus near Pacheco Pass	12/31/2011	12/31/2011	Tendered			
2/2/2007	Active	WT	W	1000	La Rumorosa, Baja CA	Mexico	SDGE	Imperial Valley 500kV bus	12/31/2011	12/31/2011				
2/9/2007	Active	WT	W	500	Solano	CA	PGE	Vaca-Tesla 500kV line	12/31/2011	12/31/2011				
3/23/2007	Active	WT	W	200	Kern	CA	SCE	Windhub Substation	12/15/2013	12/15/2013				
Wind Subtotal			**W Total**	**14412**										
Grand Total			***Grand Total***	***26802***										

East Bay Power Authority

(EBPA)

Energy Efficiency Program Potential

bases for

Supply Portfolio – Energy Efficiency Procurement

Resource Development Management, Inc.

May 2, 2007

Table of Contents

Executive Summary

Overview

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

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

Preliminary program planning is prepared based on the conduct of an energy efficiency forecast that employs key assumptions and methodologies adopted by IOUs, tailored to EBPA'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.

Findings

Conservative estimates indicate energy efficiency potential exists in EBPA's territory to save 28,600 MWh annually achievable through implementing energy efficiency programs funded at approximately $4.1 million. The following table summarizes these findings:

EBPA Service Territory

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	897,249,696	482,319,881	163,126,154	12,708,828	1.4%	3,382	$2,224,558
Commercial	1,241,595,231	165,003,537	120,249,752	14,920,685	1.2%	2,545	$1,831,694
Industrial	528,233,896	70,150,040	66,178,871	961,191	0.2%	148	$35,062
Composite	2,667,078,823	717,473,459	349,554,777	28,590,704		6,076	$4,091,315

To achieve energy efficiency program content parity with IOU procurement portfolios, EBPA's resource plan would need to include energy efficiency resources equal to approximately 22.5 percent of forecast achievable energy efficiency potential within its proposed service territory.

This would require EBPA's resource portfolio to include energy efficiency activities resulting in approximately 6,400 MWh energy savings, annually, following a ramp-up period.[1]

[1] Energy Efficiency Resource Standards: Experience and Recommendations, American Council For An Energy-Efficiency Economy, March 2006, page 29-31 – Target Size

Section 1 Introduction

1.1 Overview

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

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8.) Large Commercial/Industrial

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

As related above, the forecast cites program achievable energy efficiency impacts within the EBPA customer base. How these impacts are achieved would be based upon how programs are planned, implemented and verified by the serving distribution utility, PG&E, or by EBPA, consistent with CCA enabling legislation. Determining how the impacts might be achieved or what parties would administrate the perspective energy efficiency programs are not within the scope of this study. The purpose of this study is to determine the amount of energy efficiency to include in EBPA's resource portfolio so as to achieve parity with IOU procurement practices.

In 2003 the CPUC ordered IOUs to file plans to include energy efficiency as part of their long-term procurement supply portfolios for the first year, five years, and twenty years[2].
The table below shows projected procurement costs for utility energy efficiency programs for the years 2004 through 2008 ($ millions):

[2] CPUC Decision D.0312062 directs IOUs recover authorized procurement-related energy efficiency [costs] through its existing non-bypassable Public Purpose Programs Charge (PPPC), which applies to all IOU retail customers. Additionally, CPUC D.03-12-062 directs that incremental procurement energy efficiency costs be subject to recovery though a non-bypassable charge to all customers and orders IOUs to establish the Procurement Energy Efficiency and Balancing Account (PEEBA) to track costs and revenues.

IOU Supply Portfolio of Electric Energy Efficiency Procurement

Utility	2004	2005	2006	2007	2008	Total
PG&E	25	50	50	75	100	300
SCE	60	60	60	60	60	300
SDG&E	25	25	25	25	25	125
Total	**110**	**135**	**135**	**160**	**185**	**725**

Source: California Energy Commission

Projected procurement supply portfolio energy efficiency funding for the most recent energy efficiency funding cycle, years 2006 through 2008, is an average of $160 million. This represents approximately 22.5% of the total authorized energy efficiency expenditures during the same time period reflected in the table below:

Combined CPUC Jurisdictional Energy Utilities EE Funding

CPUC Decision D.05-09-043, ATTACHMENT 4: PROGRAM BUDGETS AND PROJECTED SAVINGS

Generic Category	2006	2007	2008	Total
Residential Retrofit	$189,867,797	$217,013,456	$250,092,210	$656,973,462
Residential New Construction	$20,429,162	$23,029,097	$26,309,717	$69,767,976
Nonresidential Retrofit	$201,460,844	$224,263,076	$261,866,097	$687,590,018
Nonresidential New Construction	$24,149,938	$28,682,705	$36,191,810	$89,024,453
Agricultural Programs	$24,119,551	$26,376,764	$35,089,650	$85,585,965
Mixed	$17,330,351	$17,330,351	$17,330,351	$51,991,053
Mixed New Construction	$2,025,969	$2,292,121	$2,705,890	$7,023,980
Third-Party	$44,024,365	$48,459,022	$53,449,545	$145,932,932
Marketing & Outreach	$20,528,085	$20,528,085	$20,528,085	$61,584,255
Education & Training	$22,942,700	$23,705,044	$24,273,357	$70,921,101
Emerging Technologies	$9,764,000	$9,902,440	$10,113,177	$29,779,617
Codes & Standards	$4,043,500	$4,206,287	$4,337,844	$12,587,631
Totals	$580,686,262	$645,788,448	$742,287,733	$1,968,762,443
Evaluation, Measurement & Verification	$47,956,836	$53,606,929	$61,771,788	$163,335,553
Total	$628,643,098	$699,395,377	$804,059,521	$2,132,097,996

To achieve energy efficiency program content parity with IOU procurement portfolios, EBPA's resource plan would need to include energy efficiency resources equal to approximately 22.5 percent of forecast achievable energy efficiency potential within its proposed service territory. This would require EBPA's resource portfolio to include energy efficiency activities resulting in approximately 6,400 MWh energy savings, annually, following a ramp-up period.[3] The sections that follow address program achievable energy efficiency potential in the EBPA service territory.

[3] Ibid *(footnote No. 1)*

1.2 Approach

The method used for estimating potential is a "bottom-up" approach in which energy efficiency costs and savings are assessed at the customer segment and energy-efficiency measure level. Cost-effective program savings potential is estimated as a function of measure economics, rebate levels, and program marketing and education efforts. The modeling approach was implemented using RDMI's Local Energy-Efficiency Potential (REEP) Model. REEP allows for efficient integration of large quantities of measure, building and economic data in the determination of energy efficiency potential.

1.3 Study Scope

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

The scope of the forecast focuses on cost-effective programs that can be planned and implemented to yield the maximum efficiency gains in the near-term. As shown in the following table, 85% of energy efficiency potential resides in existing building retrofit programs for residential, commercial and industrial customers.[4]

Energy Efficiency Market Potential

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

1.4 Report Organization

The remainder of this report is organized as follows:

- Section 2 presents forecast methods and scenario assumptions

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

- Section 3 presents energy efficiency potential forecast for existing residential dwellings
- Section 4 presents energy efficiency potential forecast for existing commercial buildings
- Section 5 presents industrial sector energy efficiency potential
- Section 6 cites report information sources
- Appendix C-1 – Program Achievable Energy Efficiency Supply Curve Bases
- Appendix C-2 – Sector Energy Efficiency Measures
- Appendix C-3 – Industrial Sector Incentive Percentages of Measure Costs
- Appendix C-4 – Avoided Cost Assumptions

Section 2 Methods and Scenario Assumptions

This forecast applies information taken from a variety of sources listed under Section 7 Sources below.

2.1 Defining Energy Efficiency Potential

Energy efficiency potential studies were popular throughout the utility industry from the late 190s through the mid-1990s. This period coincided with the advent of what was called least-cost or integrated resource planning. Energy efficiency potential studies became one of the primary means of characterizing the resource availability and value of energy efficiency within the overall resource planning process.

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

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

Naturally occurring potential the amount of savings estimated to occur as result of normal market forces absent programmatic intervention. For the purposes of this forecast RDMI incorporated prototypical net-to-gross ratios[5,6] to account for naturally occurring measure adoption and program free-ridership as follows:

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

[5] Rulemaking 01-08-028, Decision 05-04-051, Attachment 3 – Energy Efficiency Policy Manual – Version 3, CPUC, April 2005
[6] E3 program cost-effectiveness calculator version 3b5

2.2 Summary of Analytical Steps

This energy efficiency forecast was performed on the conduct of a number of basic analytical steps to produce estimates of the energy efficiency potentials introduced above. The bulk of the analytical process for the study was carried out in REEP developed by RDMI for conducting energy efficiency potential studies. RDMI's REEP is a Microsoft Excel®- based model that integrates technology specific engineering and customer behavior data with utility market saturation data, load shapes, rate projections, and marginal costs into an easily updated data management system. The key analytical steps conducted are:

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

Step 1: Develop Initial Input Data

Development of Measure List (Appendix C-2)

Residential Sector: The list of measures was developed by starting with measures included in the referenced residential sector energy efficiency potential study.[7] Two major changes were incorporated into this initial list of measures: (1) Compact Fluorescent Lamp (CFL) types and sizes were expanded from three generic CLF applications to eight, varying by ranges of wattage and fixture configuration, and (2) heating ventilation and air conditioning measure efficiencies were adjusted to align with new the new federal efficiency standards.[8]

Commercial Sector: The list of commercial sector measures were developed by reconciling the list of measures presented in two key commercial sector potential studies[9] updated to reflect new federal efficiency standards.[10]

Industrial Sector: Industrial sector measure data were provided by Lawrence Berkeley National Laboratories as presented in a recently completed industrial sector energy efficiency potential forecast.[11]

Gather and Develop Measure Technical Data (costs and savings) on efficient measure opportunities.[12]

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[7] California Statewide Residential Sector Energy Efficiency Potential Study, KEMA-XENERGY, April 2003
[8] 10 CFR 430.32 Residential Air Conditioners and Heat Pumps and 10 CFR 431.97 Commercial Minimum Cooling and Heating Efficiency Standards
[9] SW039A California Statewide commercial Sector Energy Efficiency Potential Study, Xenergy, May 2003 and PGE0252.01 California Energy Efficiency Potential Study, Itron, May 2006
[10] Ibid (footnote 3)
[11] PGE0252.01 California Industrial Existing Construction Energy Efficiency Potential Study, KEMA, May 2006

Gather, Analyze and Develop Building Characteristics: Information includes such building characteristics as number of households, building type square footage, and electricity consumption and intensity by end use, end-use consumptive load patterns, market shares of baseline efficiency electric consuming equipment, and market shares of energy efficient technologies and practices.[13]

Step 2: Estimate Technical Potential

Estimating Technical Potential is accomplished using the following core equation:

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

where:

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

Step 3: Estimate Economic Potential and Supply Curves

[12] 2004-2005 Database for Energy Efficient Resources, Version 2.01, California Public Utilities Commission (CPUC) and California Energy Commission, November 2005 – Certain measure savings, i.e., lighting measures were derived using segment specific engineering calculations

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

Economic Potential: As introduced in Section 2.2 *economic potential* is the technical potential of those energy conservation measures that are cost effective when compared to supply-side alternatives. The Total Resource Cost (TRC) test[14] is applied to assess cost effectiveness. Expressed as a benefit cost ratio, measure benefits are divided by program and participant costs, and must yield a ratio greater than 1.0 to be considered *cost-effective*. Benefits are the net present value of avoided supply costs (Avoided Cost Assumptions, see Appendix C-4). Incentives are treated as *transfer* payments and are not considered in the TRC cost test.

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

Step 4: Estimate Achievable Program Potential

Energy efficiency potential studies (Section 7 Sources) employ varying methods to predict program participation rates. This forecast adopts the assumption that program funding is tied to customer awareness and willingness to adopt. Under this reasoning consumer awareness is linked to marketing budgets and willingness to adopt is linked to incentives that offset the incrementally higher cost of energy efficient technologies.

Estimating achievable program potential is accomplished by applying a series of screens. First, the applicability factor, incomplete factor and feasibility factor are applied to render economic potential *eligible stock* (residential dwellings or commercial floor space). Second, awareness is considered and the *unaware* consumer associated building stock is removed. Third, adoption is calculated as a function of the Participant Cost Test. [15]

Consumer Awareness Screen: This forecast treats *lack of* consumer awareness as a market barrier to adoption and applies a 25% assumption of awareness to impose realistic limits on forecast market potential. This approximation was adopted in both SW039A California Statewide Commercial Sector energy Efficiency Study, Xenergy, July 2002 (2002 study) and PGE0211.01 California Energy Efficiency Potential Study, Itron May 2006 (2004 study).[16]

Participant Cost Test Screen: The participant cost test is the measure of quantifiable benefits and costs to the customer due to participation in a program. Benefits of

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

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

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

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

Energy efficiency forecasts (Sources Section 7) apply either the benefit-cost ratio or the payback period as the final screen to project customer adoption. The benefit-cost ratio is the ratio of total benefits of a program to the total costs. The payback period is the number of years it takes until the cumulative benefits equal the costs. Both benefit-cost ratio and payback period methods yield acceptance curves where consumer probability to participate are projected. This forecast applies the payback period method consistent with the most recent major energy efficient forecast for residential, commercial and industrial customer sectors.[17]

2.3 Planning Scenario – Base Assumptions

Because achievable potential depends on the type and degree of intervention applied, **potential** estimates typically include alternative funding scenarios. Given the scope and time-frame, RDMI constrained its forecast to a single achievable program scenario based on historic program funding of similar programs[18].

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

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

The following table summarizes the baseline planning scenario assumptions adopted:

Sector	Measure Category	Incentive % Measure Cost	Program Cost - Administration	Program Cost Incentives
Residential[19]	All	33%	20%	80%
Commercial	Lighting	32.6%	20%	80%
	HVAC	45.8%	20%	80%
	Refrigeration	60.9%	20%	80%
	Office Equip.	50.0%	20%	80%
Industrial[20]	125 Measures	Variable Appendix C-3	52.6%	47.4%

Administration program cost include marketing costs

2.4 Determination of Cost-Effective Programs

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

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

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

The SPM states[21] "A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g., environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate." At the same page the SPM also states "The benefits calculated in the Total Resource Cost Test are the avoided costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction."

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

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

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

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

Section 3 Energy Efficiency in Existing Residential Dwellings

3.1 Residential Sector Program Achievable Energy Efficiency Potential

The tables below provide an overview of the residential sector and measures comprising over 90% of 12,700 MWh (annualized) forecast program achievable energy savings potential:

EBPA EE Forecast Model Inputs

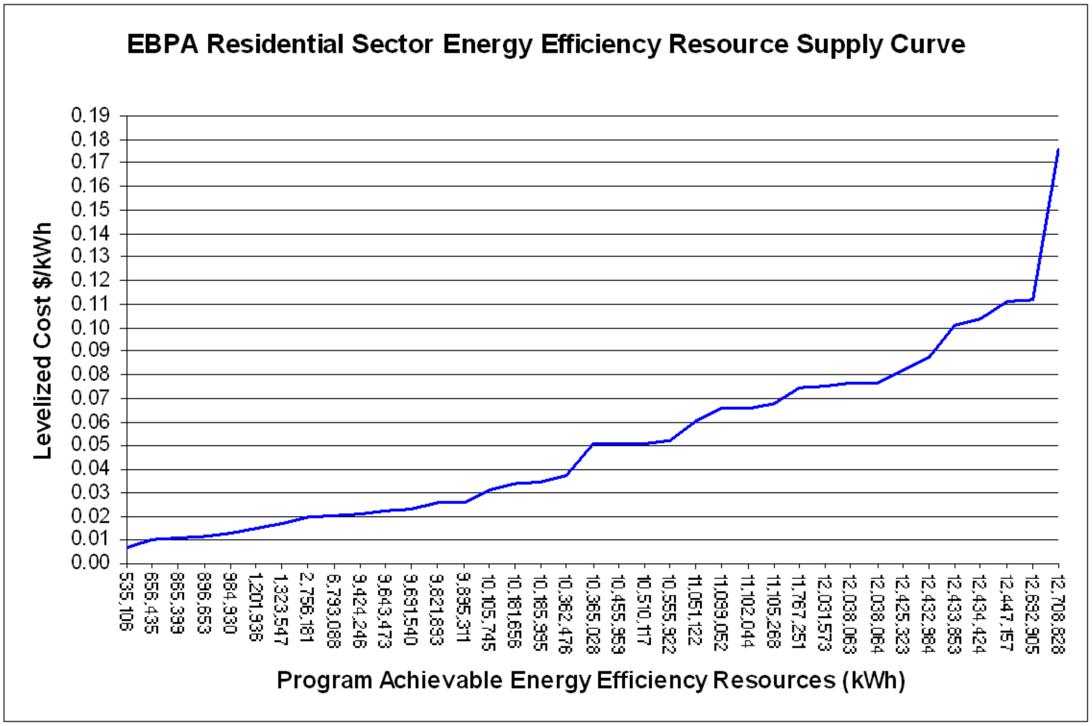
Residential Housing Stock

	2008 Dwellings
Single Family Post-1978	11,639
Single Family Pre-1979	98,062
Multi-Family Post-1978	127,444
Multi-Family Pre-1979	98,062
Mobile Homes Post-1978	19
Mobile Homes Pre-1979	149
Buildings	335,375

EBPA Residential Sector Forecast Program Achievable Measures

Measure Description	Levelized Cost	Program kWh
26-50W CFL Screw-in	0.0200	4,036,906
23-26W CFL Screw-in	0.0212	2,631,159
26-50W CFL Hard-wire	0.0199	1,432,634
18-22W CFL Screw-in	0.0746	661,983
Water Heater Blanket	0.0066	535,106
Thermal Expansion Valve (TXV)	0.0602	495,200
Basic HVAC Diagnostic Testing And Repair	0.0820	387,259
9-12W CFL Screw-in	0.0752	264,322
13-17W CFL Screw-in	0.1121	245,748
Low Flow Showerhead	0.0225	219,227
Ceiling R-0 to R-19 Insulation Blown-in	0.0150	217,007
23-26W CFL Hard-wire	0.0315	210,435
Double Pane Clear Windows to Double Pane, Med Low-E	0.0111	208,964

As shown below in this residential sector energy efficiency supply curve, there are significant economic opportunities for energy savings at or below current and projected supply-side alternatives.



See APPENDIX C-1 – PROGRAM ACHIEVABLE ENERGY EFFICIENCY SUPPLY CURVE BASES

3.2 Residential Sector Costs and Benefits

Provided below are residential sector achievable energy efficiency program potential program annual program cost, the net-present-value of the associated avoided cost of supply, TRC cost-benefit ratio, PAC cost-benefit ratio and levelized cost calculated as prescribed in the California Standard Practice Manual (SPM).[22]

Program Cost	NPV Avoided Cost Benefits	TRC	PAC	Levelized Cost $/kWh
$2,225,000	$9,680,000	1.9	4.4	$0.0294

Section 4 Energy Efficiency Potential in Existing Commercial Buildings

4.1 Commercial Sector Program Achievable Energy Efficiency Potential

The tables below provide an overview of the residential sector and measures comprising over 90% of 14,900 MWh (annualized) forecast program achievable energy savings potential:

[22] ibid

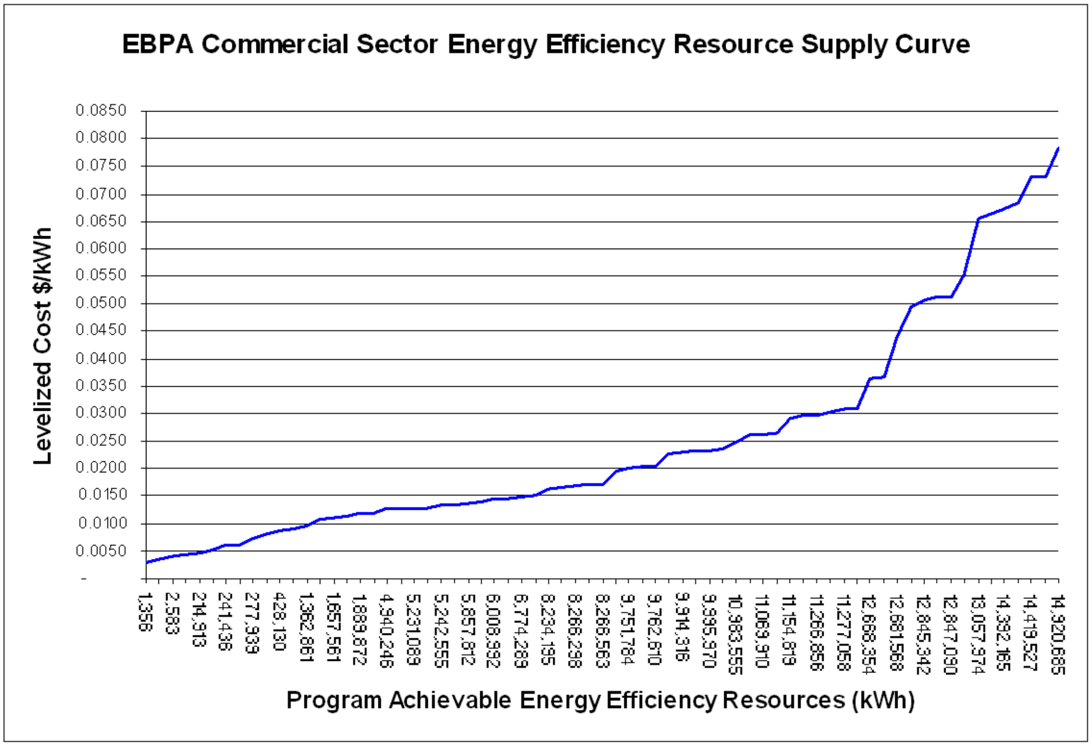
Commercial Building Stock

	2008 Energy (kWh)	Floor Space ft^2	kWh/ft^2
Colleges	26,547,545	2,223,412	11.94
Food Stores	60,148,143	1,483,674	40.54
Health Care	120,542,699	6,512,301	18.51
Lodging	47,067,827	4,812,661	9.78
Large Offices	217,081,869	12,944,655	16.77
Misc	165,611,279	12,788,516	12.95
Refrigerated Warehouses	970,717	52,471	18.50
Retail Stores	121,652,748	9,979,717	12.19
Restaurants	77,297,869	2,333,873	33.12
Schools	36,808,278	5,397,108	6.82
Small Offices	337,838,750	25,043,643	13.49
Warehouses	30,027,507	6,165,813	4.87
	1,241,595,231		

EBPA Commercial Sector Forecast Program Achievable Measures

Measure Description	Levelized Cost	Program kWh
HO T5 4-Lamp Hi-Bay fixture	0.0127	3,044,093
Occupancy Sensor - Motion Sensor - Retrofit	0.0664	1,197,100
T8 Lamp, 2nd Gen Elec Ballast (8Ft) Fixture Change	0.0363	1,065,135
38W CFL Screw-in, Base 120W Incandescent	0.0196	973,945
15W CFL Screw-in, Base 60W Incandescent	0.0164	951,638
10W CFL Screw-in, Base 40W Incandescent	0.0247	927,782
20W CFL Screw-in, Base 75W Incandescent	0.0146	654,513
15W CFL Hardwired, Base 60W Incandescent	0.0136	613,690
20W CFL Hard-wire, Base 75W Incandescent	0.0097	608,156
Night Covers for Vertical Display Case	0.0201	511,276
10W CFL Hardwired, Base 40W Incandescent	0.0150	508,269
14W CFL Reflector - Screw-in, Base as 60W Incandescent	0.0730	500,914
Interior Metal Halide 175W, Base 500W Incandescent	0.0091	326,576
HE T8 or T5 Fixture w/Elec Ballast (4Ft)	0.0309	326,161
Interior Metal Halide 100W, Base 300W Incandescent	0.0108	293,618
38W CFL Hard-wire, Base 120W Incandescent	0.0128	286,581
Time Clock	0.0656	210,879
Interior Metal Halide 70W, Base 200W Incandescent	0.0114	209,371
Night Covers for Horizontal Display Case	0.0505	163,405
New Glass Doors w/ECM Fan Motor, T8 Lamps and Electronic Ballas	0.0230	151,664

As shown below in this commercial sector energy efficiency supply curve, there are significant economic opportunities for energy savings at or below the current and projected supply-side alternatives.



See APPENDIX C-1 – PROGRAM ACHIEVABLE ENERGY EFFICIENCY SUPPLY CURVE BASES

4.2 Commercial Sector Costs and Benefits

Provided below are commercial sector achievable energy efficiency program potential program annual program cost, the net-present-value of the associated avoided cost of supply, TRC cost-benefit ratio, PAC cost-benefit ratio and levelized cost calculated as prescribed in the SPM.

Program Cost	NPV Avoided Cost Benefits	TRC	PAC	Levelized Cost $/kWh
$1,832,000	$9,613,000	2.1	5.2	$0.0220

Section 5 Industrial Sector Energy Efficiency Potential

5.1 Industrial Sector Program Achievable Energy Efficiency Potential

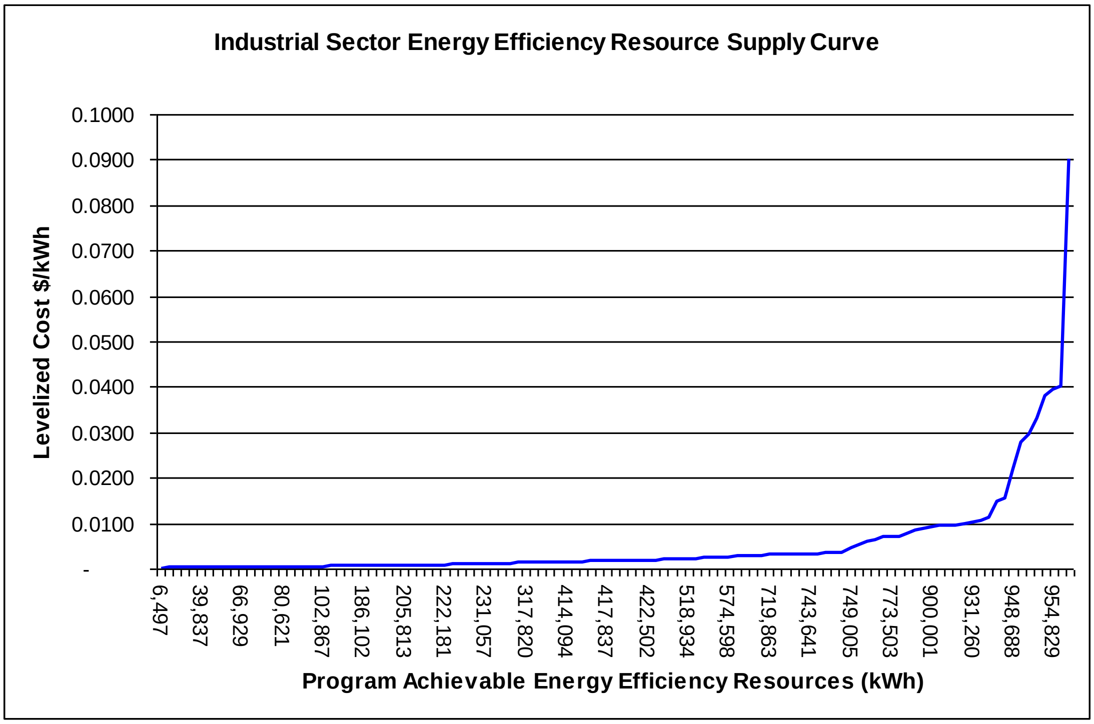
The tables below provide an overview of the residential sector and measures comprising over 90% of 961 MWh (annualized) forecast program achievable energy savings potential:

Industrial Building Stock

Market Segment	SIC Codes	NAIC Code	2008 Energy (kWh)
Food Processing	20	311, 312	57,768,030
Textiles/Apparel	22/23	313, 314, 315	1,279,144
Lumber/Furniture	24/25	321, 337	2,572,962
Paper	26	322	2,654,337
Printing	27	323	51,837,932
Chemicals	28	325	122,349,901
Petro/Coal	29	324	2,476,134
Rubber/Plastics	30	326	1,599,322
Stone/Clay/Glass	32	327	63,516,950
Prim Metals	33	331	48,587,374
Fab Metals	34	332	4,696,292
Ind Mach	35	333	6,018,415
Electronics	36	334, 335	11,426,333
Transp Equip	37	336	0
Instruments	38	339	4,138,655
Misc Mfg	21/31/39	312, 316, 339	147,312,114
			528,233,896

EBPA Industrial Sector Forecast Program Achievable Measures		
Measure Description	Levelized Cost	Program kWh
Pumps - Controls	0.0028	117,890
Pumps - System Optimization	0.0078	102,415
Compressed Air-O&M	0.0011	77,926
Compressed Air - System Optimization	0.0019	61,157
Pumps - O&M	0.0005	46,511
Pumps - Sizing	0.0024	45,993
Pumps - ASD (100+ hp)	0.0013	44,226
Fans - Controls	0.0095	31,185
Pumps - ASD (6-100 hp)	0.0003	26,949
Fans - ASD (100+ hp)	0.0013	24,414
Compressed Air - ASD (100+ hp)	0.0013	23,523
Compressed Air- Sizing	0.0005	22,535
Fans - System Optimization	0.0071	18,779
Compressed Air - Controls	0.0020	18,347
Drives - Process Controls (batch + site)	0.0027	16,857
Fans - ASD (6-100 hp)	0.0003	14,876
Compressed Air - ASD (6-100 hp)	0.0003	14,333
Efficient Practices Printing Press	0.0004	13,271
Pumps - Motor Practices-1 (100+ HP)	0.0005	10,469
Pumps - Motor Practices-1 (6-100 HP)	0.0006	9,963
Efficient Printing Press (fewer cylinders)	0.0071	9,779
Pumps - Replace 6-100 HP Motor	0.0030	8,589
Pumps - Replace 100+ HP Motor	0.0020	8,123
Bakery - Process	0.0032	8,114
Optimization Refrigeration	0.0070	7,314
Efficient Curing Oven	0.0051	6,798
Fans - O&M	0.0001	6,497
Efficient Refrigeration - Operations	0.0009	6,495
Fans- Improve Components	0.0006	6,419
Fans - Motor Practices-1 (100+ HP)	0.0005	5,779
Compressed Air - Motor Practices-1 (100+ HP)	0.0005	5,568
CFL Hardwired, Modular 36W	0.0901	5,533
Fans - Motor Practices-1 (6-100 HP)	0.0006	5,500
Prog. Thermostat - DX	0.0218	5,497
Other Process Controls (batch + site)	0.0027	5,348
Compressed Air - Motor Practices-1 (6-100 HP)	0.0006	5,299
Clean Room - Controls	0.0023	5,264
Efficient Drives - Rolling	0.0011	4,766
Fans - Replace 6-100 HP Motor	0.0030	4,741
Light Cylinders	0.0083	4,723

As shown below in this industrial sector energy efficiency supply curve, there are significant economic opportunities for energy savings at or below the current and projected supply-side alternatives.



See APPENDIX C-1 – PROGRAM ACHIEVABLE ENERGY EFFICIENCY SUPPLY CURVE BASES

5.2 Industrial Sector Cost and Benefit Results

Provided below are industrial sector achievable energy efficiency program potential program annual program cost, the net-present-value of the associated avoided cost of supply, TRC cost-benefit ratio, PAC cost-benefit ratio and levelized cost calculated as prescribed in the SPM.

Program Cost	NPV Avoided Cost Benefits	TRC	PAC	Levelized Cost $/kWh
$35,100	$665,400	13.1	19,0	$0.0036

Section 6 Sources

Sources

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APPENDIX C-1 – PROGRAM ACHIEVABLE ENERGY EFFICIENCY SUPPLY CURVE BASES

EBPA Residential Sector Forecast Program Achievable Measures - Supply Curve Bases

Measure Description	Levelized Cost	Cumulative kWh	Program kWh
Water Heater Blanket	0.0066	535,106	535,106
Pipe Wrap	0.0102	656,435	121,329
Double Pane Clear Windows to Double Pane, Med Low-E	0.0111	865,399	208,964
Double Pane Clear Windows to Double Pane, Med Low-E	0.0118	896,653	31,254
Energy Star CW (EF=2.5)	0.0129	984,930	88,277
Ceiling R-0 to R-19 Insulation Blown-in	0.0150	1,201,936	217,007
SEHA CW Tier 2 (EF=3.25)	0.0172	1,323,547	121,611
26-50W CFL Hard-wire	0.0199	2,756,181	1,432,634
26-50W CFL Screw-in	0.0200	6,793,088	4,036,906
23-26W CFL Screw-in	0.0212	9,424,246	2,631,159
Low Flow Showerhead	0.0225	9,643,473	219,227
Ceiling R-0 to R-19 Insulation Blown-in (.29)	0.0234	9,691,540	48,067
Faucent Aerator	0.0256	9,821,893	130,354
Ceiling R-0 to R-19 Insulation Blown-in (.29)	0.0258	9,895,311	73,417
23-26W CFL Hard-wire	0.0315	10,105,745	210,435
High Efficiency Pool Pump and Motor	0.0342	10,181,656	75,910
Duct Insulation (.4)	0.0349	10,185,995	4,340
Wall 2x4 R-0 to Blow-In R-13 Insulation	0.0377	10,362,476	176,481
Ceiling R-19 to R-38 Insulation Blown-in	0.0506	10,365,028	2,552
Heat Pump Space Heater	0.0508	10,455,959	90,931
Duct Repair (0.32)	0.0512	10,510,117	54,158
Programmable Thermostat (0.4)	0.0520	10,555,922	45,805
Thermal Expansion Valve (TXV)	0.0602	11,051,122	495,200
Programmable Thermostat	0.0660	11,099,052	47,930
Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)	0.0661	11,102,044	2,991
HE Clothes Dryer (EF=.52)	0.0675	11,105,268	3,224
18-22W CFL Screw-in	0.0746	11,767,251	661,983
9-12W CFL Screw-in	0.0752	12,031,573	264,322
Window Film	0.0764	12,038,063	6,490
Ceiling R-19 to R-38 Insulation Blown in (.27)	0.0764	12,038,064	1
Basic HVAC Diagnostic Testing And Repair	0.0820	12,425,323	387,259
Heat Pump Water Heater (EF=2.9)	0.0874	12,432,984	7,661
Programmable Thermostat (0.4)	0.1010	12,433,853	869
Whole House Fan	0.1040	12,434,424	571
Attic Venting	0.1111	12,447,157	12,733
13-17W CFL Screw-in	0.1121	12,692,905	245,748
Direct Evaporative Cooler	0.1755	12,708,828	15,923
		11,437,945	

EBPA Commercial Sector Forecast Program Achievable Measures - Supply Curve Bases

Measure Description	Levelized Cost	Cumulative kWh	Program kWh
Exterior Pulse Start Metal Halide 100W, Base 300W Incandescent	0.0029	1,356	1,356
Network Power Management Enabling	0.0034	2,582	1,226
Fan Motor, 15 HP, 1800 rpm, 92.4%	0.0041	2,583	1
Exterior Pulse Start Metal Halide 250W, Base 700W Incandescent	0.0044	86,815	84,232
Interior Metal Halide (Pulse Start) Fixture	0.0047	214,913	128,098
Floating Head Pressure Controller - Multiplex Compress	0.0052	232,331	17,418
Install Strip Curtail on Walk-in Cooler Doorway	0.0060	241,436	9,105
HE Chiller - 0.51 kW per Ton, 500 Tons, Base 5.8 kW/Ton	0.0060	241,862	426
Exterior Pulse Start Metal Halide 175W, Base 500W Incandescent	0.0074	277,939	36,077
Interior Metal Halide 250 W, Base 750W Incandescent	0.0080	420,584	142,645
LED Exit Sign	0.0087	428,130	7,546
Interior Metal Halide 175W, Base 500W Incandescent	0.0091	754,705	326,576
20W CFL Hard-wire, Base 75W Incandescent	0.0097	1,362,861	608,156
Interior Metal Halide 100W, Base 300W Incandescent	0.0108	1,656,479	293,618
Variable Speed Drive Control, 15 HP	0.0111	1,657,561	1,082
Interior Metal Halide 70W, Base 200W Incandescent	0.0114	1,866,932	209,371
Exterior Pulse Start 250W MH	0.0119	1,889,872	22,940
Programmable Thermostat	0.0121	1,896,153	6,281
HO T5 4-Lamp Hi-Bay fixture	0.0127	4,940,246	3,044,093
38W CFL Hard-wire, Base 120W Incandescent	0.0128	5,226,828	286,581
Anti-Sweat Heater Controls - Low Temp Glass Door Case	0.0128	5,231,089	4,261
Efficient Low Temperature Compressor EER >= 5.2	0.0128	5,237,539	6,451
Electronically Commutated (ECM) Evaporator Fan Motor, Walk-in Co	0.0133	5,242,555	5,015
Electronically Commutated (ECM) Evaporator Fan Motor	0.0133	5,244,122	1,567
15W CFL Hardwired, Base 60W Incandescent	0.0136	5,857,812	613,690
Fan Motor, 5 HP, 1800 rpm, 89.5%	0.0140	5,857,812	1
New Glass Doors w/ECM Fan Motor, T8 Lamps and Electronic Ballas	0.0146	6,008,992	151,180
20W CFL Screw-in, Base 75W Incandescent	0.0146	6,663,505	654,513
Interior HID Fixture 176-250W	0.0148	6,774,289	110,784
10W CFL Hardwired, Base 40W Incandescent	0.0150	7,282,557	508,269
15W CFL Screw-in, Base 60W Incandescent	0.0164	8,234,195	951,638
Cool Roof (DX)	0.0164	8,265,905	31,710
Reflectors with Delamping, (8-foot lamp removed)	0.0170	8,266,298	394
Variable Speed Drive Control, 5 HP	0.0172	8,266,563	264
Fan Motor, 40 HP, 1800 rpm, 94.1%	0.0173	8,266,563	0
38W CFL Screw-in, Base 120W Incandescent	0.0196	9,240,508	973,945
Night Covers for Vertical Display Case	0.0201	9,751,784	511,276
Exterior 100W Metal Halide	0.0204	9,757,197	5,413
Exterior Pulse Start Metal Halide 175W	0.0204	9,762,610	5,413
Reflective Window Film - Single Pane - Retrofit (base DX)	0.0228	9,762,651	42
New Glass Doors w/ECM Fan Motor, T8 Lamps and Electronic Ballas	0.0230	9,914,316	151,664
Interior HID Fixture 101-175W	0.0233	9,947,938	33,622
Interior HID Fixture 71-100W	0.0233	9,995,970	48,032
SS/SP AC & HP >760 kBtuh, EER 10.8 - Base EER 9.3	0.0235	10,055,773	59,803
10W CFL Screw-in, Base 40W Incandescent	0.0247	10,983,555	927,782
SS/SP AC & HP 135-240 kBtuh, EER 12.0 - Base EER 9.7	0.0261	11,017,802	34,247
Efficient Condenser Added to Standard Multiplex System	0.0262	11,069,910	52,108
Permanent-Split Capacitor (PSC) Evaporator Fan Motor	0.0266	11,070,281	371
Reflectors with Delamping, (4-foot lamp removed)	0.0291	11,154,819	84,538
Cool Roof (Chiller)	0.0296	11,243,487	88,668
Cooling Cir. Pumps - VSD	0.0296	11,266,856	23,369
Split-System AC <65 kBtuh, SEER 14 - Base SEER 13	0.0304	11,269,781	2,925
SS/SP AC & HP 240-760 kBtuh, EER 14.0 - (W/C) Base EER 10.1	0.0309	11,277,058	7,277
HE T8 or T5 Fixture w/Elec Ballast (4Ft)	0.0309	11,603,219	326,161
T8 Lamp, 2nd Gen Elec Ballast (8Ft) Fixture Change	0.0363	12,668,354	1,065,135
Chiller Tune Up / Diagnostics	0.0366	12,668,401	46
Reflective Window Film - Single Pane - Retrofit (base chiller)	0.0439	12,681,568	13,167
SS/SP AC & HP 65-135 kBtuh, EER 12.0 - Base EER 10.1	0.0496	12,681,937	369
Night Covers for Horizontal Display Case	0.0505	12,845,342	163,405
Interior HID Fixture 36-70W	0.0512	12,846,903	1,561
Single Package AC <65 kBtuh, SEER 14 - Base SEER 13	0.0513	12,847,090	187
Evaporative Pre-Cooler (DX)	0.0552	12,847,095	5
Time Clock	0.0656	13,057,974	210,879
Occupancy Sensor - Motion Sensor - Retrofit	0.0664	14,255,074	1,197,100
Evaporator Fan Motor Controller for Walk-in Cooler	0.0672	14,392,165	137,090
DX Tune Up / Advanced Diagnostics	0.0684	14,392,519	354
Photocell Control	0.0729	14,419,527	27,009
14W CFL Reflector - Screw-in, Base as 60W Incandescent	0.0730	14,920,441	500,914
Occupancy Sensor - Plug Load	0.0784	14,920,685	244

EBPA Industrial Sector Forecast Program Achievable Measures - Supply Curve Bases			
Measure Description	Levelized Cost	Cumulative kWh	Program kWh
Fans - O&M	0.0001	6,497	6,497
Process Control	0.0002	8,633	2,137
Process Drives - ASD	0.0002	10,510	1,877
High Consistency Forming	0.0003	10,628	118
Compressed Air - ASD (6-100 hp)	0.0003	24,961	14,333
Fans - ASD (6-100 hp)	0.0003	39,837	14,876
Pumps - ASD (6-100 hp)	0.0003	66,786	26,949
Gap Forming Paper Machine	0.0003	66,908	122
Power Recovery	0.0003	66,908	0
Power Recovery	0.0004	66,921	13
Power Recovery	0.0004	66,929	8
Power Recovery	0.0004	66,983	53
Refinery Controls	0.0004	67,048	66
Refinery Controls	0.0004	67,311	263
Refinery Controls	0.0004	67,350	39
Efficient Practices Printing Press	0.0004	80,621	13,271
Refinery Controls	0.0004	80,622	0
O&M - Extruders/Injection Moulding	0.0004	81,052	430
Fans - Motor Practices-1 (100+ HP)	0.0005	86,830	5,779
Pumps - Motor Practices-1 (100+ HP)	0.0005	97,299	10,469
Compressed Air - Motor Practices-1 (100+ HP)	0.0005	102,867	5,568
Compressed Air- Sizing	0.0005	125,402	22,535
Pumps - O&M	0.0005	171,913	46,511
Bakery - Process (Mixing) - O&M	0.0005	174,184	2,271
Fans- Improve Components	0.0006	180,603	6,419
Fans - Motor Practices-1 (6-100 HP)	0.0006	186,102	5,500
Compressed Air - Motor Practices-1 (6-100 HP)	0.0006	191,401	5,299
Pumps - Motor Practices-1 (6-100 HP)	0.0006	201,364	9,963
Top-Heating (glass)	0.0006	202,603	1,240
Efficient Drives	0.0007	205,390	2,787
Replace V-Belts	0.0007	205,813	422
Drives - EE Motor	0.0007	208,574	2,762
Efficient Machinery	0.0007	210,654	2,080
Near Net Shape Casting	0.0008	211,623	968
Drives - Process Control	0.0008	215,686	4,063
Efficient Refrigeration - Operations	0.0009	222,181	6,495
Drives - Optimization Process (M&T)	0.0009	223,104	923
Heating - Process Control	0.0009	227,094	3,990
Heating - Optimization Process (M&T)	0.0009	227,523	429
Process Control	0.0010	227,787	264
Drives - Scheduling	0.0011	231,057	3,271
Compressed Air-O&M	0.0011	308,983	77,926
Efficient Drives - Rolling	0.0011	313,749	4,766
Heating - Scheduling	0.0011	313,890	141
Efficient Electric Melting	0.0013	317,437	3,547
Optimization Control PM	0.0013	317,820	382
Compressed Air - ASD (100+ hp)	0.0013	341,343	23,523
Fans - ASD (100+ hp)	0.0013	365,757	24,414
Pumps - ASD (100+ hp)	0.0013	409,983	44,226
Fans - Motor Practices-1 (1-5 HP)	0.0014	411,445	1,462
Pumps - Motor Practices-1 (1-5 HP)	0.0014	414,094	2,649
Compressed Air - Motor Practices-1 (1-5 HP)	0.0014	415,503	1,409
Machinery	0.0015	415,991	488
Energy Star Transformers	0.0016	416,776	785
Energy Star Transformers	0.0016	417,081	305
Energy Star Transformers	0.0016	417,837	756
Energy Star Transformers	0.0016	418,814	977
Energy Star Transformers	0.0016	420,236	1,422
Energy Star Transformers	0.0016	422,176	1,940
Energy Star Transformers	0.0016	422,422	246
Intelligent Extruder (DOE)	0.0019	422,502	80
Compressed Air - System Optimization	0.0019	483,660	61,157
Compressed Air - Controls	0.0020	502,007	18,347
Compressed Air - Replace 100+ HP Motor	0.0020	506,327	4,320
Fans - Replace 100+ HP Motor	0.0020	510,811	4,484
Pumps - Replace 100+ HP Motor	0.0020	518,934	8,123
Clean Room - Controls	0.0023	524,198	5,264
Pumps - Sizing	0.0024	570,191	45,993
Compressed Air - Replace 1-5 HP Motor	0.0026	571,316	1,125
Fans - Replace 1-5 HP Motor	0.0026	572,483	1,168
Pumps - Replace 1-5 HP Motor	0.0026	574,598	2,115
Other Process Controls (batch + site)	0.0027	579,946	5,348
Drives - Process Controls (batch + site)	0.0027	596,803	16,857
Air Conveying Systems	0.0027	597,404	601
Pumps - Controls	0.0028	715,295	117,890
Compressed Air - Replace 6-100 HP Motor	0.0030	719,863	4,568
Fans - Replace 6-100 HP Motor	0.0030	724,604	4,741
Pumps - Replace 6-100 HP Motor	0.0030	733,192	8,589
Process Optimization	0.0031	734,450	1,258
Efficient Processes (welding, etc.)	0.0032	735,526	1,076
Bakery - Process	0.0032	743,641	8,114
New Transformer - Welding	0.0032	744,270	629
Compressed Air - ASD (1-5 hp)	0.0037	745,478	1,208
Fans - ASD (1-5 hp)	0.0037	746,732	1,254
Pumps - ASD (1-5 hp)	0.0037	749,004	2,272
Efficient Desalter	0.0047	749,005	1
Efficient Curing Oven	0.0051	755,804	6,798
Optimize Drying Process	0.0059	756,210	406
Injection Moulding - Impulse Cooling	0.0063	756,411	201
Optimization Refrigeration	0.0070	763,725	7,314
Efficient Printing Press (fewer cylinders)	0.0071	773,503	9,779
Fans - System Optimization	0.0071	792,283	18,779
Pumps - System Optimization	0.0078	894,698	102,415
Light Cylinders	0.0083	899,421	4,723
Injection Moulding - Direct Drive	0.0088	899,591	171
Extruders/Injection Moulding-Multipump	0.0090	900,001	410
Energy Star Transformers	0.0094	900,009	8
Energy Star Transformers	0.0094	900,025	16
Fans - Controls	0.0095	931,209	31,185
Energy Star Transformers	0.0099	931,251	42
Energy Star Transformers	0.0103	931,260	9
Centrifugal Chiller, 0.51 kW/ton, 500 tons	0.0105	935,780	4,520
Heat Pumps - Drying	0.0113	935,852	72
Efficient Grinding	0.0148	939,280	3,428
Clean Room - New Designs	0.0156	943,191	3,911
Prog. Thermostat - DX	0.0218	948,688	5,497
Direct Drive Extruders	0.0280	948,744	56
RET 2L4' Premium T8, 1EB	0.0294	951,651	2,907
Replace V-belts	0.0329	951,692	41
Chiller Tune Up/Diagnostics	0.0380	951,892	200
Occupancy Sensor, 4L4' Fluorescent Fixtures	0.0396	954,829	2,937
Window Film - DX	0.0400	955,658	829
CFL Hardwired, Modular 36W	0.0901	961,191	5,533

Residential Measure Description

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

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

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

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

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

Base Refrigerator
HE Refrigerator - Energy Star
Refrigerator - Early Replacement

Base Freezer
HE Freezer

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

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

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

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

Base Pool Pump
High Efficiency Pool Pump and Motor

Commercial Measure Description

Lighting

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

Space Cooling

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

Ventilation

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

Office Equipment

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

Refrigeration

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

Industrial Measure Description

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

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

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

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

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

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

Other
Replace V-belts
Membranes for wastewater
Energy Star Transformers

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

Refrigeration
Efficient Refrigeration - Operations
Optimization Refrigeration
Energy Star Transformers

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

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

APPENDIX C - INDUSTRIAL MEASURE INCENTIVE AMOUNMTS

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

APPENDIX D-3 – AVOIDED COST ASSUMPTIONS

Avoided Energy Costs

	Summer ON-Peak $/MWh				Summer Off-Peak $/MWh			
Year	**Gen**	**T&D**	**Env. Ext.**	**Total**	**Gen**	**T&D**	**Env. Ext.**	**Total**
1	102.34			102.34	69.05			69.05
2	104.90			104.90	70.78			70.78
3	107.52			107.52	72.55			72.55
4	110.21			110.21	74.36			74.36
5	112.97			112.97	76.22			76.22
6	115.79			115.79	78.12			78.12
7	118.69			118.69	80.08			80.08
8	121.65			121.65	82.08			82.08
9	124.69			124.69	84.13			84.13
10	127.81			127.81	86.23			86.23
11	131.01			131.01	88.39			88.39
12	134.28			134.28	90.60			90.60
13	137.64			137.64	92.86			92.86
14	141.08			141.08	95.19			95.19
15	144.61			144.61	97.57			97.57
16	148.22			148.22	100.01			100.01
17	151.93			151.93	102.51			102.51
18	155.73			155.73	105.07			105.07
19	159.62			159.62	107.69			107.69
20	163.61			163.61	110.39			110.39

	Winter On-Peak $/MWh			
Year	**Gen**	**T&D**	**Env. Ext.**	**Total**
2007				
2008	85.08			85.08
2009	87.21			87.21
2010	89.39			89.39
2011	91.62			91.62
2012	93.91			93.91
2013	96.26			96.26
2014	98.67			98.67
2015	101.13			101.13
2016	103.66			103.66
2017	106.25			106.25
2018	108.91			108.91
2019	111.63			111.63
2020	114.42			114.42
2021	117.28			117.28
2022	120.22			120.22
2023	123.22			123.22
2024	126.30			126.30
2025	129.46			129.46
2026	132.70			132.70
2027	136.01			136.01

APPENDIX H-4 Pro Forma 2013 – 2025
EAST BAY POWER AUTHORITY
FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION

CATEGORY	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
I, CUSTOMER ACCOUNTS:													
RESIDENTIAL	263,970	267,930	271,949	276,028	280,168	284,371	288,636	292,966	297,360	301,821	306,348	310,943	315,607
SMALL COMMERCIAL1	19,938	20,238	20,541	20,849	21,162	21,479	21,802	22,129	22,461	22,797	23,139	23,486	23,839
SMALL COMMERCIAL2	1,267	1,286	1,305	1,325	1,345	1,365	1,386	1,406	1,427	1,449	1,471	1,493	1,515
MEDIUM COMMERCIAL	2,718	2,759	2,801	2,843	2,885	2,928	2,972	3,017	3,062	3,108	3,155	3,202	3,250
LARGE COMMERCIAL	409	415	421	427	434	440	447	454	460	467	474	481	489
LARGE COMMERCIAL & INDUSTRIAL	54	55	55	56	57	58	59	60	61	61	62	63	64
STREET LIGHTING AND TRAFFIC CONTROL	1,157	1,174	1,192	1,210	1,228	1,246	1,265	1,284	1,303	1,323	1,343	1,363	1,383
AGRICULTURAL	3	3	3	3	3	3	3	3	3	3	4	4	4
SUBTOTAL - CUSTOMER ACCOUNTS	289,516	293,859	298,267	302,741	307,282	311,891	316,570	321,318	326,138	331,030	335,996	341,035	346,151
II. LOAD REQUIREMENTS (KWH):													
RESIDENTIAL	893,351,417	906,751,689	920,352,964	934,158,258	948,170,632	962,393,192	976,829,090	991,481,526	1,006,353,749	1,021,449,055	1,036,770,791	1,052,322,353	1,068,107,188
SMALL COMMERCIAL1	308,879,353	313,512,544	318,215,232	322,988,460	327,833,287	332,750,786	337,742,048	342,808,179	347,950,302	353,169,556	358,467,099	363,844,106	369,301,768
SMALL COMMERCIAL2	73,195,883	74,293,821	75,408,229	76,539,352	77,687,442	78,852,754	80,035,545	81,236,079	82,454,620	83,691,439	84,946,811	86,221,013	87,514,328
MEDIUM COMMERCIAL	494,358,639	501,774,019	509,300,629	516,940,138	524,694,241	532,564,654	540,553,124	548,661,421	556,891,342	565,244,712	573,723,383	582,329,234	591,064,172
LARGE COMMERCIAL	372,805,096	378,397,173	384,073,130	389,834,227	395,681,741	401,616,967	407,641,221	413,755,840	419,962,177	426,261,610	432,655,534	439,145,367	445,732,547
LARGE COMMERCIAL & INDUSTRIAL	475,686,631	482,821,931	490,064,260	497,415,224	504,876,452	512,449,599	520,136,343	527,938,388	535,857,464	543,895,326	552,053,755	560,334,562	568,739,580
STREET LIGHTING AND TRAFFIC CONTROL	37,214,152	37,772,364	38,338,949	38,914,034	39,497,744	40,090,210	40,691,563	41,301,937	41,921,466	42,550,288	43,188,542	43,836,370	44,493,916
AGRICULTURAL	58,743	59,624	60,519	61,426	62,348	63,283	64,232	65,196	66,174	67,166	68,174	69,196	70,234
SUBTOTAL - LOAD REQUIREMENTS	2,655,549,915	2,695,383,164	2,735,813,911	2,776,851,120	2,818,503,887	2,860,781,445	2,903,693,167	2,947,248,564	2,991,457,293	3,036,329,152	3,081,874,089	3,128,102,201	3,175,023,734
III. IOU UNBUNDLED RATE FOR GENERATION COMPONENT ($/KWH):													
RESIDENTIAL	$0.087	$0.090	$0.091	$0.092	$0.093	$0.094	$0.097	$0.101	$0.105	$0.107	$0.109	$0.111	$0.114
SMALL COMMERCIAL1	$0.098	$0.101	$0.103	$0.104	$0.105	$0.106	$0.109	$0.114	$0.118	$0.120	$0.123	$0.125	$0.128
SMALL COMMERCIAL2	$0.093	$0.096	$0.097	$0.099	$0.100	$0.101	$0.104	$0.108	$0.112	$0.114	$0.117	$0.119	$0.122
MEDIUM COMMERCIAL	$0.094	$0.097	$0.098	$0.099	$0.100	$0.101	$0.104	$0.109	$0.113	$0.115	$0.118	$0.120	$0.123
LARGE COMMERCIAL	$0.086	$0.089	$0.090	$0.091	$0.092	$0.093	$0.096	$0.100	$0.104	$0.106	$0.108	$0.110	$0.113
LARGE COMMERCIAL & INDUSTRIAL	$0.081	$0.084	$0.085	$0.086	$0.087	$0.088	$0.091	$0.095	$0.098	$0.100	$0.102	$0.104	$0.107
STREET LIGHTING AND TRAFFIC CONTROL	$0.081	$0.084	$0.085	$0.086	$0.087	$0.088	$0.091	$0.095	$0.098	$0.100	$0.102	$0.104	$0.107
AGRICULTURAL	$0.083	$0.086	$0.087	$0.088	$0.089	$0.090	$0.093	$0.097	$0.100	$0.102	$0.105	$0.107	$0.109
SUBTOTAL - AVERAGE RATE	$0.088	$0.091	$0.092	$0.093	$0.094	$0.095	$0.098	$0.102	$0.106	$0.108	$0.110	$0.112	$0.115
IV. IOU REVENUE REQUIREMENT FOR POWER SUPPLY ($):													
RESIDENTIAL	$77,496,289	$81,522,526	$83,805,444	$86,102,381	$88,238,572	$90,500,596	$94,567,719	$100,298,194	$105,341,748	$109,170,128	$113,097,224	$117,003,157	$121,727,159
SMALL COMMERCIAL1	$30,167,427	$31,734,743	$32,623,428	$33,517,570	$34,349,137	$35,229,688	$36,812,921	$39,043,656	$41,006,989	$42,497,285	$44,026,008	$45,546,493	$47,385,432
SMALL COMMERCIAL2	$6,797,679	$7,150,845	$7,351,094	$7,552,572	$7,739,951	$7,938,367	$8,295,120	$8,797,775	$9,240,176	$9,575,987	$9,920,457	$10,263,071	$10,677,442
MEDIUM COMMERCIAL	$46,245,052	$48,647,665	$50,009,971	$51,380,643	$52,655,391	$54,005,229	$56,432,239	$59,851,837	$62,861,522	$65,146,065	$67,489,516	$69,820,339	$72,639,335
LARGE COMMERCIAL	$31,998,174	$33,660,605	$34,603,220	$35,551,624	$36,433,656	$37,367,645	$39,046,957	$41,413,067	$43,495,548	$45,076,284	$46,697,780	$48,310,537	$50,261,075
LARGE COMMERCIAL & INDUSTRIAL	$38,585,050	$40,589,695	$41,726,350	$42,869,984	$43,933,584	$45,059,835	$47,084,837	$49,938,015	$52,449,177	$54,355,310	$56,310,593	$58,255,340	$60,607,399
STREET LIGHTING AND TRAFFIC CONTROL	$3,019,376	$3,176,245	$3,265,191	$3,354,683	$3,437,913	$3,526,045	$3,684,506	$3,907,774	$4,104,279	$4,253,439	$4,406,444	$4,558,626	$4,742,680
AGRICULTURAL	$4,883	$5,136	$5,280	$5,425	$5,560	$5,702	$5,958	$6,319	$6,637	$6,878	$7,126	$7,372	$7,670
SUBTOTAL - POWER SUPPLY REVENUE REQUII	$234,313,929	$246,487,459	$253,389,978	$260,334,882	$266,793,764	$273,633,108	$285,930,257	$303,256,637	$318,506,076	$330,081,376	$341,955,148	$353,764,933	$368,048,192
IOU MELDED RATE FOR POWER SUPPLY ($/KW	$0.088	$0.091	$0.093	$0.094	$0.095	$0.096	$0.098	$0.103	$0.106	$0.109	$0.111	$0.113	$0.116
V. CCA POWER SUPPLY REVENUE REQUIREMENT ($)													
(A) MARKET PURCHASES	$31,835,263	$30,754,591	$29,205,361	$24,574,946	$24,825,244	$25,145,167	$26,621,141	$29,062,557	$30,946,361	$32,016,729	$33,361,741	$34,424,960	$35,256,124
(B) CONTRACT PURCHASES	$127,341,054	$123,018,366	$116,821,443	$98,299,786	$99,300,974	$100,580,669	$106,484,563	$116,250,227	$123,785,445	$128,066,914	$133,446,963	$137,699,840	$138,518,768
(C) POWER PRODUCTION (NON-DEBT)	$3,717,446	$3,834,527	$3,954,535	$4,077,543	$4,203,626	$4,332,862	$4,465,328	$4,601,106	$4,740,278	$4,882,930	$10,823,888	$10,823,888	$10,823,888
(D) RESOURCE PORTFOLIO STANDARDS	$42,454,996	$56,393,537	$70,585,882	$89,218,758	$91,955,927	$94,768,432	$97,658,244	$100,627,385	$103,677,929	$106,812,002	$110,031,784	$113,339,512	$116,737,480
(E) DWR POWER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(F) ANCILLARY SERVICES	$0	$0	$0	$14,022,378	$14,347,115	$14,710,364	$15,533,748	$16,744,010	$17,751,543	$18,457,879	$19,285,411	$20,019,241	$20,508,304
(G) EXIT FEES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$756,086
(I) CAPITAL & DEBT COVERAGE	$18,135,442	$14,302,103	$14,302,103	$14,302,103	$14,302,103	$14,302,103	$14,302,103	$14,302,103	$14,302,103	$14,302,103	$14,302,103	$14,302,103	$14,302,103
(J) ISO GRID MANAGEMENT CHARGE (GMC)	$0	$0	$0	$5,939,685	$6,209,643	$6,491,871	$6,786,927	$7,095,393	$7,417,878	$7,755,021	$8,107,487	$8,475,972	$8,861,205
(K) OPERATIONS & SCHEDULING COORDINAT	$5,796,532	$5,854,497	$5,913,042	$5,972,173	$6,031,894	$6,092,213	$6,153,135	$6,214,667	$6,276,813	$6,339,582	$6,402,977	$6,467,007	$6,531,677
(L) FRANCHISE FEES	$1,777,505	$1,869,854	$1,922,216	$1,974,900	$2,023,897	$2,075,781	$2,169,067	$2,300,505	$2,416,187	$2,503,997	$2,594,072	$2,683,661	$2,786,278
(M) BILLING	$2,659,774	$2,726,668	$2,795,243	$2,865,544	$2,937,612	$3,011,493	$3,087,232	$3,164,876	$3,244,473	$3,326,071	$3,409,722	$3,495,476	$3,583,387
(N) UNCOLLECTABLES	$1,869,744	$1,910,033	$1,963,999	$2,089,983	$2,129,104	$2,172,088	$2,266,092	$2,402,903	$2,516,472	$2,595,706	$2,734,129	$2,813,853	$2,869,322
SUBTOTAL - CCA REVENUE REQUIREMENT	$235,587,757	$240,664,176	$247,463,824	$263,337,799	$268,267,140	$273,683,043	$285,527,580	$302,765,732	$317,075,484	$327,058,934	$344,500,276	$354,545,514	$361,534,625
VII. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VIII. CCA REVENUE REQUIREMENT - NET MARKET SALES	$235,587,757	$240,664,176	$247,463,824	$263,337,799	$268,267,140	$273,683,043	$285,527,580	$302,765,732	$317,075,484	$327,058,934	$344,500,276	$354,545,514	$361,534,625
IV. CCA MELDED RATE FOR POWER SUPPLY ($/KWH)	$0.089	$0.089	$0.090	$0.095	$0.095	$0.096	$0.098	$0.103	$0.106	$0.108	$0.112	$0.113	$0.114
VARIANCE - IOU MINUS CCA ($)	($1,273,828)	$5,823,283	$5,926,154	($3,002,916)	($1,473,376)	($49,935)	$402,677	$490,906	$1,430,592	$3,022,442	($2,545,128)	($780,581)	$6,513,567
DISCOUNT ON POWER SUPPLY REVENUE REQUIREMENTS	-1%	2%	2%	-1%	-1%	0%	0%	0%	0%	1%	-1%	0%	2%
DISCOUNT ON TOTAL REVENUE REQUIREMENTS	0%	1%	1%	-1%	0%	0%	0%	0%	0%	1%	0%	0%	1%

Crystal Ball Report - Full

Simulation started on 1/18/2008 at 13:36:04

Simulation stopped on 1/18/2008 at 13:50:04

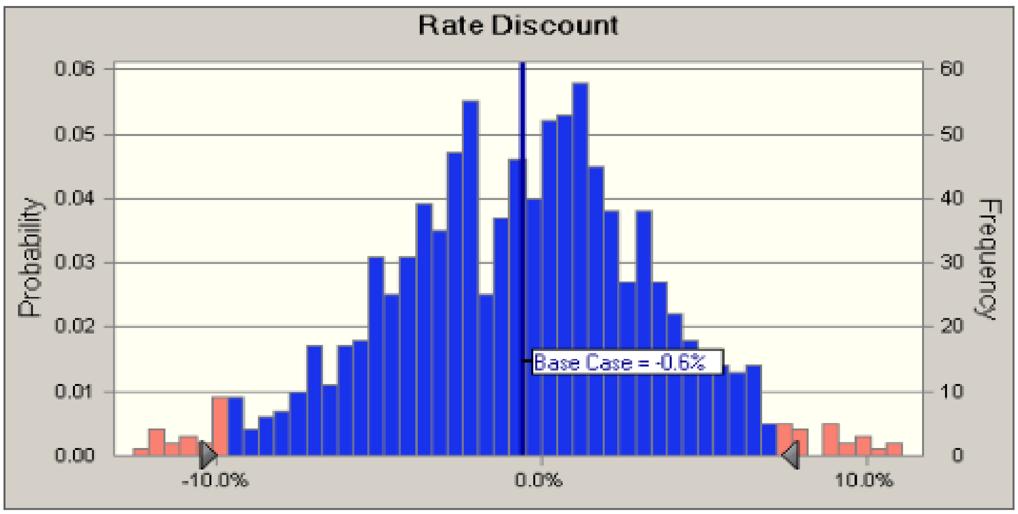
Run preferences:	
Number of trials run	1,000
Monte Carlo	
Random seed	
Precision control on	
Confidence level	95.00%
Run statistics:	
Total running time (sec)	840.22
Trials/second (average)	1
Random numbers per sec	30
Crystal Ball data:	
Assumptions	25
Correlations	0
Correlated groups	0
Decision variables	0
Forecasts	3

Forecasts

Worksheet: [BEO Monte Carlo Jan 08.xls]Combined Load Aggregation

Forecast: Rate Discount **Cell: Z111**

Summary:
- Certainty level is 95.0%
- Certainty range is from -9.9% to 7.2%
- Entire range is from -13.9% to 11.6%
- Base case is -0.6%
- After 1,000 trials, the std. error of the mean is 0.1%



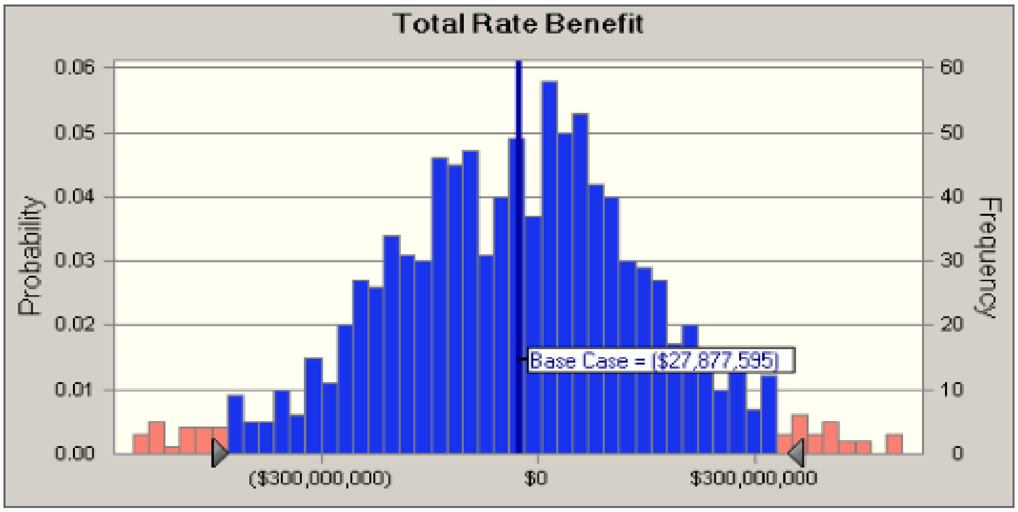
Statistics:	Forecast values
Trials	1,000
Mean	-0.8%
Median	-0.5%
Mode	---
Standard Deviation	4.2%
Variance	0.2%
Skewness	-0.2081
Kurtosis	3.24
Coeff. of Variability	-5.60
Minimum	-13.9%
Maximum	11.6%
Range Width	25.5%
Mean Std. Error	0.1%

Forecast: Rate Discount (cont'd) **Cell: Z111**

Percentiles:	Forecast values
P100	-13.9%
P90	-6.1%
P80	-4.1%
P70	-2.8%
P60	-1.8%
P50	-0.5%
P40	0.5%
P30	1.4%
P20	2.6%
P10	4.3%
P0	11.6%

Forecast: Total Rate Benefit **Cell: Z110**

Summary:
Certainty level is 95.0%
Certainty range is from ($426,311,982) to $337,519,562
Entire range is from ($626,267,493) to $605,101,020
Base case is ($27,877,595)
After 1,000 trials, the std. error of the mean is $6,023,062



Statistics:	Forecast values
Trials	1,000
Mean	($29,208,168)
Median	($22,436,731)
Mode	---
Standard Deviation	$190,465,959
Variance	###############
Skewness	-0.0271
Kurtosis	3.29
Coeff. of Variability	-6.52
Minimum	($626,267,493)
Maximum	$605,101,020
Range Width	$1,231,368,513
Mean Std. Error	$6,023,062

Forecast: Total Rate Benefit (cont'd)

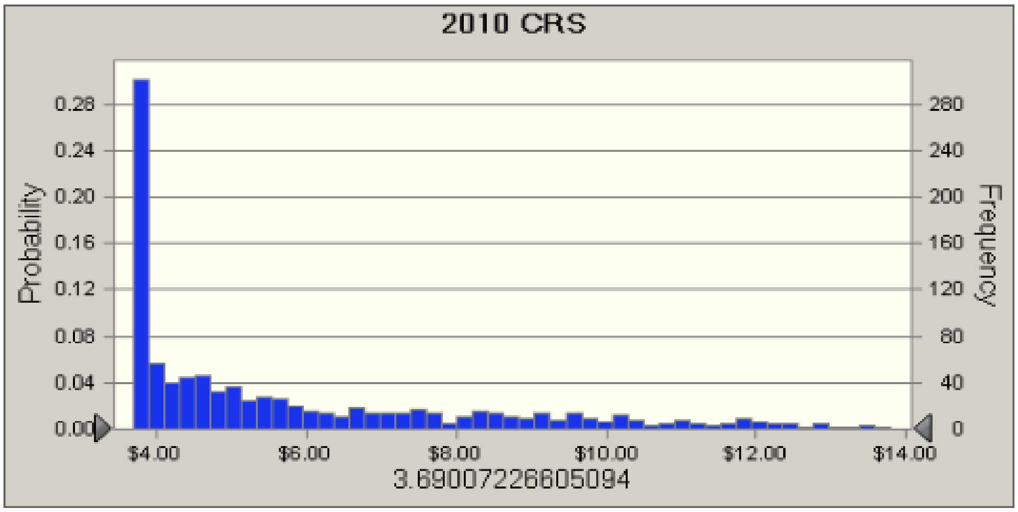
Cell: Z110

Percentiles:	Forecast values
P100	($626,267,493)
P90	($264,217,526)
P80	($185,350,874)
P70	($126,522,018)
P60	($78,492,458)
P50	($22,436,731)
P40	$23,809,571
P30	$65,890,256
P20	$117,725,116
P10	$206,013,198
P0	$605,101,020

Worksheet: [BEO Monte Carlo Jan 08.xls]Exit Fees

Forecast: 2010 CRS **Cell: AJ48**

Summary:
Entire range is from $3.69 to $18.73
Base case is $3.69
After 1,000 trials, the std. error of the mean is $0.09



Statistics:	Forecast values
Trials	1,000
Mean	$5.97
Median	$4.80
Mode	$3.69
Standard Deviation	$2.79
Variance	$7.81
Skewness	1.47
Kurtosis	4.77
Coeff. of Variability	0.4682
Minimum	$3.69
Maximum	$18.73
Range Width	$15.04
Mean Std. Error	$0.09

Forecast: 2010 CRS (cont'd) **Cell: AJ48**

Percentiles:	Forecast values
P100	$3.69
P90	$3.69
P80	$3.69
P70	$3.89
P60	$4.32
P50	$4.80
P40	$5.49
P30	$6.61
P20	$8.23
P10	$10.16
P0	$18.73

End of Forecasts

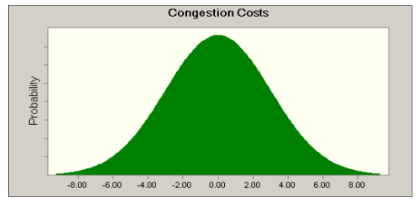
Assumptions

Worksheet: [BEO Monte Carlo Jan 08.xls]Annual L&R Summary

Assumption: Congestion Costs **Cell: K5**

Normal distribution with parameters:

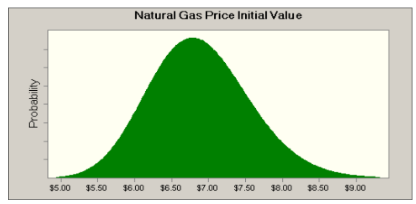
Mean	0.00
Std. Dev.	3.00



Assumption: Natural Gas Price Initial Value **Cell: K49**

Lognormal distribution with parameters:

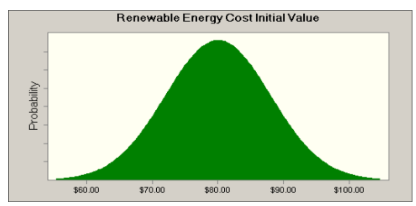
Mean	$6.88
Std. Dev.	$0.69



Assumption: Renewable Energy Cost Initial Value **Cell: I31**

Normal distribution with parameters:

Mean	$80.00
Std. Dev.	$8.00

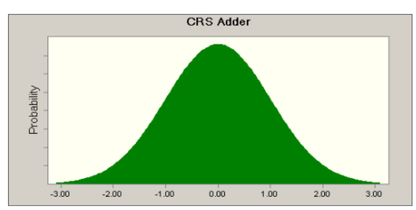


Worksheet: [BEO Monte Carlo Jan 08.xls]CCA Out

Assumption: CRS Adder **Cell: D49**

Normal distribution with parameters:

Mean	0.00
Std. Dev.	1.00



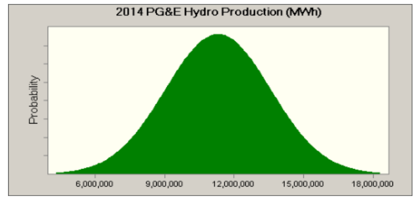
Worksheet: [BEO Monte Carlo Jan 08.xls]INPUT

Assumption: 2014 PG&E Hydro Production (MWh)

Cell: Q46

Normal distribution with parameters:

Mean	11,304,776
Std. Dev.	2,260,955

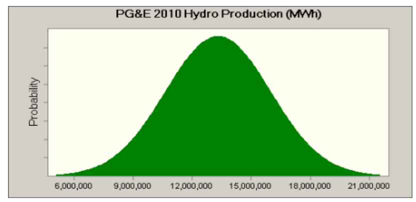


Assumption: PG&E 2010 Hydro Production (MWh)

Cell: M46

Normal distribution with parameters:

Mean	13,309,968
Std. Dev.	2,661,994

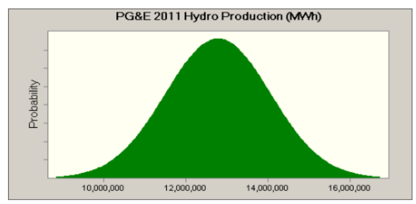


Assumption: PG&E 2011 Hydro Production (MWh)

Cell: N46

Normal distribution with parameters:

Mean	12,777,570
Std. Dev.	1,277,757

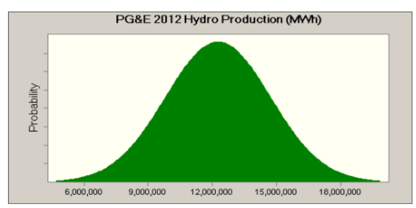


Assumption: PG&E 2012 Hydro Production (MWh)

Cell: O46

Normal distribution with parameters:

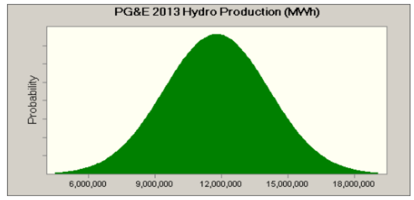
Mean	12,266,467
Std. Dev.	2,453,293



Assumption: PG&E 2013 Hydro Production (MWh) **Cell: P46**

Normal distribution with parameters:

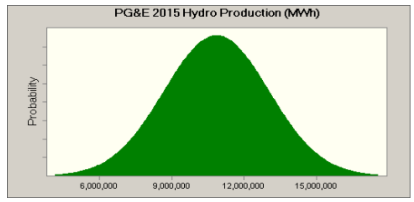
Mean	11,775,808
Std. Dev.	2,355,162



Assumption: PG&E 2015 Hydro Production (MWh) **Cell: R46**

Normal distribution with parameters:

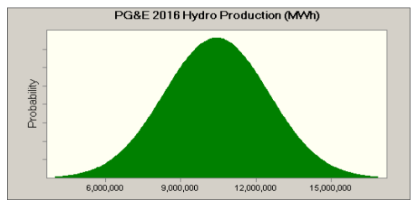
Mean	10,852,585
Std. Dev.	2,170,517



Assumption: PG&E 2016 Hydro Production (MWh) **Cell: S46**

Normal distribution with parameters:

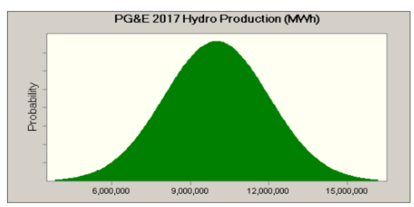
Mean	10,418,481
Std. Dev.	2,083,696



Assumption: PG&E 2017 Hydro Production (MWh) **Cell: T46**

Normal distribution with parameters:

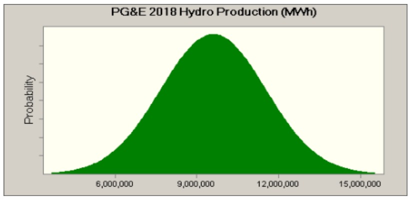
Mean	10,001,742
Std. Dev.	2,000,348



Assumption: PG&E 2018 Hydro Production (MWh) **Cell: U46**

Normal distribution with parameters:

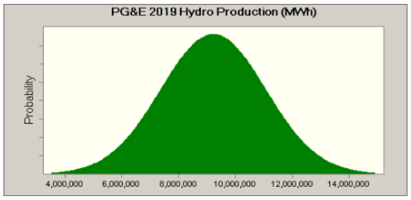
Mean	9,601,672
Std. Dev.	1,920,334



Assumption: PG&E 2019 Hydro Production (MWh) **Cell: V46**

Normal distribution with parameters:

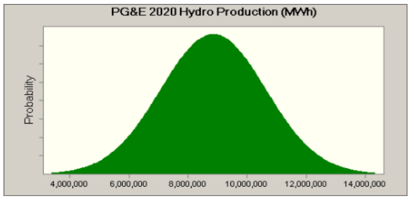
Mean	9,217,606
Std. Dev.	1,843,521



Assumption: PG&E 2020 Hydro Production (MWh) **Cell: W46**

Normal distribution with parameters:

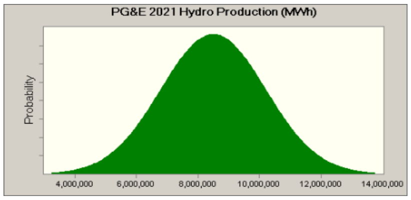
Mean	8,848,901
Std. Dev.	1,769,780



Assumption: PG&E 2021 Hydro Production (MWh) **Cell: X46**

Normal distribution with parameters:

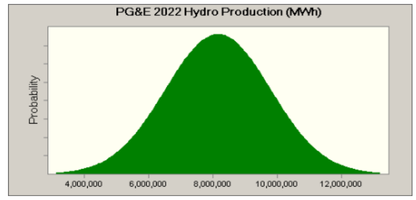
Mean	8,494,945
Std. Dev.	1,698,989



Assumption: PG&E 2022 Hydro Production (MWh) **Cell: Y46**

Normal distribution with parameters:

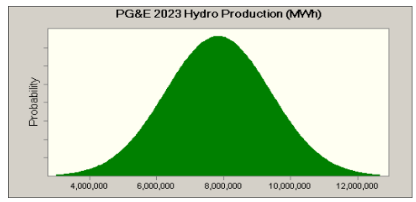
Mean	8,155,147
Std. Dev.	1,631,029



Assumption: PG&E 2023 Hydro Production (MWh) **Cell: Z46**

Normal distribution with parameters:

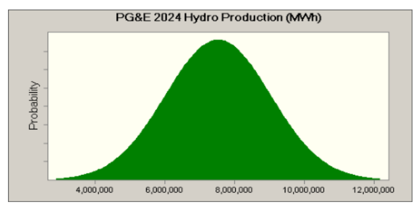
Mean	7,828,942
Std. Dev.	1,565,788



Assumption: PG&E 2024 Hydro Production (MWh) **Cell: AA46**

Normal distribution with parameters:

Mean	7,515,784
Std. Dev.	1,503,157

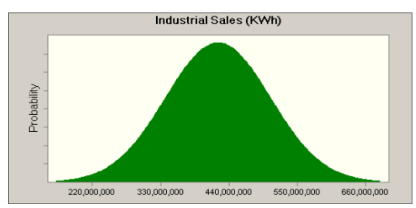


Worksheet: [BEO Monte Carlo Jan 08.xls]Load Projection - Base

Assumption: Industrial Sales (KWh) **Cell: I30**

Normal distribution with parameters:

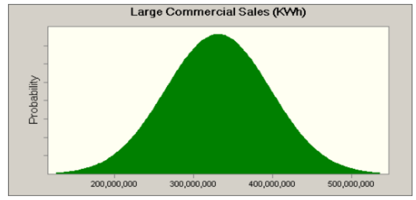
Mean	422,272,314
Std. Dev.	84,454,463



Assumption: Large Commercial Sales (KWh) **Cell: I29**

Normal distribution with parameters:

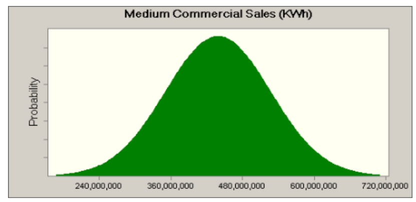
Mean	330,943,231
Std. Dev.	66,188,646



Assumption: Medium Commercial Sales (KWh) **Cell: I28**

Normal distribution with parameters:

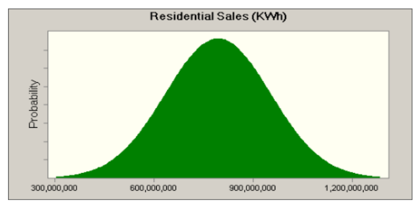
Mean	438,847,663
Std. Dev.	87,769,533



Assumption: Residential Sales (KWh) **Cell: I25**

Normal distribution with parameters:

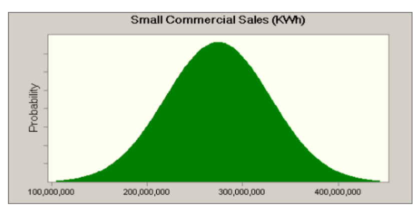
Mean	793,037,991
Std. Dev.	158,607,598



Assumption: Small Commercial Sales (KWh) **Cell: I26**

Normal distribution with parameters:

Mean	274,195,638
Std. Dev.	54,839,128

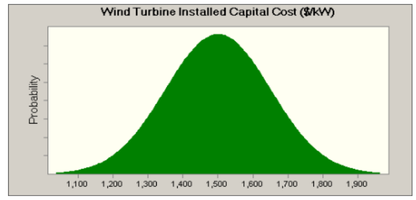


Worksheet: [BEO Monte Carlo Jan 08.xls]Toggle Sheet

Assumption: Wind Turbine Installed Capital Cost ($/kW) **Cell: H73**

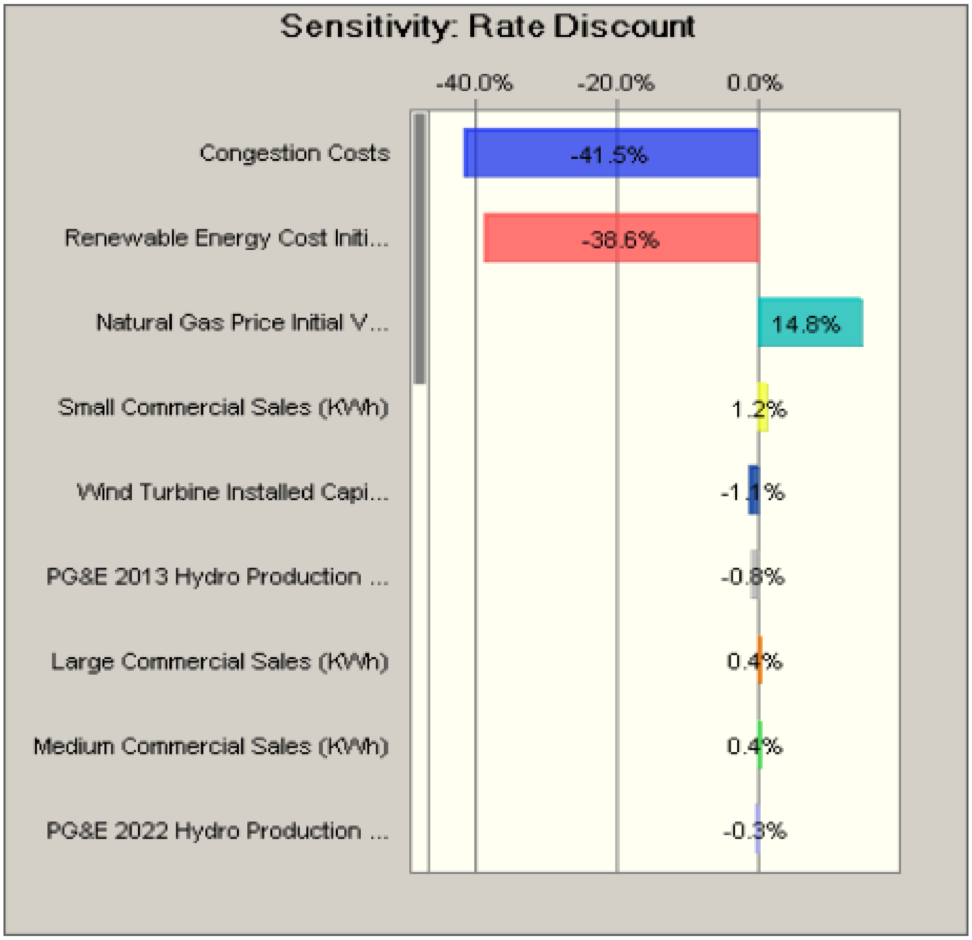
Normal distribution with parameters:

Mean	1,500
Std. Dev.	150



End of Assumptions

Sensitivity Charts



End of Sensitivity Charts

EAST BAY CITIES

COMMUNITY CHOICE AGGREGATION BUSINESS PLAN

January 2008

Prepared By Navigant Consulting, Inc
3100 Zinfandel Drive,
Rancho Cordova, CA 95670

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Beginning in 2004, the Cities of Berkeley, Emeryville and Oakland ("Cities") initiated a process to investigate offering retail electric services to customers located within the Cities through a program known as Community Choice Aggregation ("CCA"). The Cities' primary objectives in offering CCA service are to exercise local control over energy policy, promote greater use of renewable energy and reduce carbon emissions, and to offer rates that are competitive to PG&E, while insulating taxpayers from any financial liabilities.

The CCA program was established by the legislature in 2002 (AB 117) to give Cities and counties the authority to procure electricity in bulk for resale to customers within their jurisdictional boundaries. Under a CCA program the incumbent utility, in this case Pacific Gas and Electric Company ("PG&E"), would deliver the electricity to end use customers and PG&E would continue to read the electric meters and issue monthly bills to customers enrolled in the CCA program. The difference would be in the source of the electric supply (generation) and potentially in the price paid by customers for the generation services procured by the CCA program. With CCA, resource and ratemaking decisions are made locally, for the benefit of the community, rather than by private corporations for the benefit of their shareholders. All customers would be given the choice of being automatically enrolled in the Program, following a well publicized community outreach, education and customer notification process, or remaining with the incumbent utility by following the opt-out process described in the customer notices.

Each of the Cities conducted feasibility studies during 2004-2005 to identify the benefits and risks of forming CCA programs. The feasibility studies, which were subject to peer review by a team of independent, expert consultants, generally found that the Cities could, over the medium to long term, increase use of renewable energy, stabilize electric rates, and offer rates that would be competitive with PG&E. The ability for public agencies to obtain low cost capital financing for generation projects was identified as a key factor in being able to achieve these objectives. Following consideration of the feasibility study findings, the Cities decided to jointly develop a comprehensive business plan that would refine the initial analysis and address issues not included within the feasibility study scope and to confirm the study's findings in certain key respects.

This business plan presents a proposal for the three Cities to join together to form a regional CCA program serving a large portion of the East Bay to accelerate the shift away from natural gas for new electric power generation toward greater use of wind, solar, geothermal, biomass and other renewable resources. The CCA Program would seek to establish local energy efficiency and renewable energy programs. The plan sets forth proposals for how an East Bay CCA program would be organized, funded and operated. Highlights of the plan include:

- The Cities would form a new Joint Powers Agency, tentatively named the East Bay Power Authority ("Authority") for purposes of offering CCA services to customers as early as 2010 (subject to the refinement and approval by the Cities). The JPA Agreement would specify that debts and assets of the JPA are not debts or assets of the respective Cities.

- The Authority would negotiate contracts with third party electric suppliers to provide electricity to customers and provide other technical services required for the Program.
- The Authority would gradually increase its renewable energy procurement until it procures one half of its electric supply from renewable resources, such as wind, solar, geothermal and biomass by 2017.
- The Authority would develop up to 125 MW of new wind generation, financed with tax-exempt revenue bonds issued by the Authority or in conjunction with another public agency, in the 2013 timeframe.
- The Authority would target deployment of over 25 MW of distributed solar (photovoltaic) systems within its boundaries by 2017.
- The Authority would promote additional energy efficiency and energy conservation efforts within its jurisdiction, as envisioned by AB 117.
- The Authority would establish a goal of providing electric rates that are no greater than the rates charged by PG&E, subject to acceptable responses from the market to a future request for proposals, and to provide comparable or better customer service.
- Through implementation of the proposed CCA Program, the Cities would cause a reduction in greenhouse gas emissions of between 325,000 and 580,000 metric tons per year by 2017, as the renewable resources procured and developed by the Authority would displace production from natural gas fueled power plants.

The key assumptions and uncertainties underlying this plan are described in Section 8.

This business plan includes a financial plan and estimated Program rates that reflect market prices and other information provided by potential third party electric suppliers in response to a request for information issued on behalf of the Cities in January 2007. The financial plan also provides a quantitative assessment of the likelihood that the Program would be able to offer rates that are competitive with PG&E under a large number of scenarios for future electricity prices and other variables. Due to the dynamic nature of the electricity markets pending solicitation of final, firm price offers from suppliers, the financial plan presented in Chapter 4 should be considered illustrative pending solicitation of final prices that would be provided by the market once a decision is made to proceed with issuance of a request for bids. The analysis presented herein represents a snapshot in time based on market conditions and PG&E rates. Certain plan components will also require input from the Cities' legal and financial professionals, as indicated in this plan.

After considering this business plan, the Cities will need to decide whether to proceed with formation of the JPA, which would adopt the Implementation Plan for submission to the California Public Utilities Commission as required by AB 117. The key planning elements that are statutorily required in an Implementation Plan are addressed in this business plan. The Public Utilities Code specifies that a CCA Implementation Plan must include the following components:

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

California's CCA program is relatively new, and no CCA's are serving customers today. The first CCA Implementation Plan was submitted to the California Public Utilities Commission in January 2007 by the San Joaquin Valley Power Authority, a new public agency consisting of 13 cities and counties in the central San Joaquin Valley. The CPUC certified the San Joaquin Valley Power Authority's Implementation Plan on May 1, 2007, and the Program plans to begin serving customers in 2008. There are several other CCA development efforts under way in San Francisco, Marin County, Westside Los Angeles area, and Chula Vista. Many other cities and counties are in various stages of investigating the formation of CCA programs.

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

1. Governance and Organization

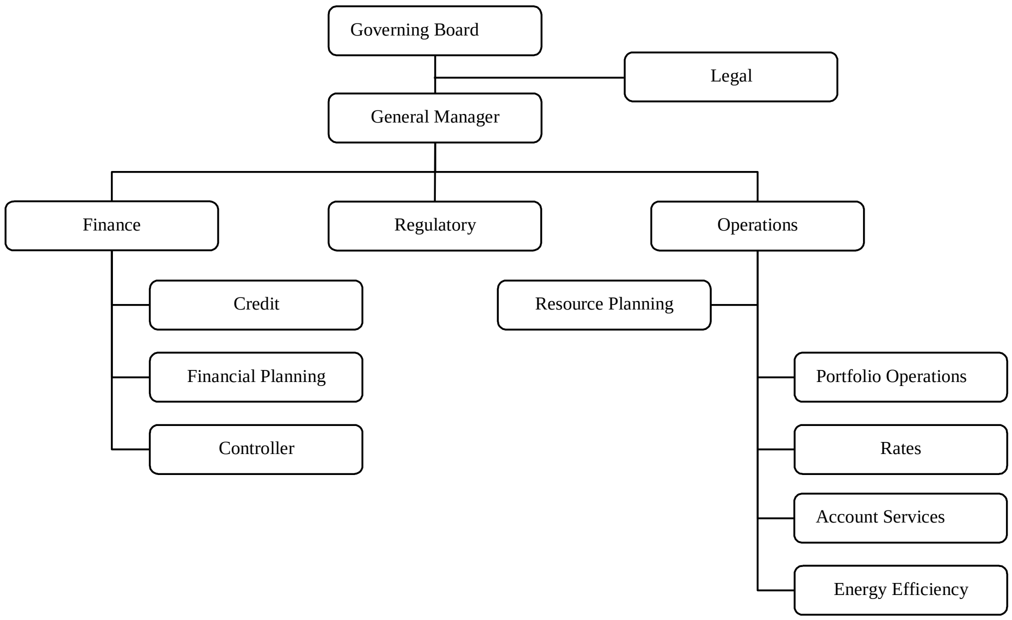
The Program would be implemented by a new JPA whose governing board would have primary responsibility for managing all aspects of the CCA program. Governing board composition and voting provisions will require additional consideration by the Cities. An initial proposal is for the JPA to be governed by a board of directors comprised of two representatives from each of the member Cities. The JPA would adopt the Implementation Plan required by the CCA legislation (AB 117) and register with the California Public Utilities Commission as a Community Choice Aggregator. Regular public meetings of the JPA would be held in accordance with the Brown Act.

The Authority would be established under the terms of a Joint Powers Agreement, which would establish the Authority with a broad set of powers to study, promote, develop and conduct electricity related projects and programs. The JPA agreement would specify the governance provisions of the Authority. A draft JPA Agreement is contained in Appendix A.

The CCA program would most likely be established pursuant to a separate project agreement (Project Agreement No. 1 or PA-1) executed by and among the Authority and the members (Cities). The PA-1 would transfer the Cities' authority under AB 117 to the Authority and authorize the initiation of CCA service to customers within the member's jurisdiction, subject to specified withdrawal rights. Proposed principles for PA-1 are contained in Appendix A.

Operations of the Program would be the responsibility of a General Manager, appointed by the Authority's Board of Directors. The General Manager would manage staff, contractors and third party electric providers, in accordance with the general policies established by the Board. The Program organizational chart showing relationships among the Governing Board, the General Manager and the functional areas is shown in Figure 1.

Figure 1: Program Organization



The Authority would have a full time staff of approximately twenty employees to perform its responsibilities, primarily related to Program and contract management, legal and regulatory, finance and accounting, marketing and customer service. Alternatively, some of these functions could be contracted out to third parties, as determined by the Program's General Manager and Governing Board. Technical functions associated with managing and scheduling electric supplies and those related to retail customer settlements would be performed by experienced third parties selected via a competitive solicitation. In the longer term, these technical functions may be performed by internal staff or continue to be provided by third parties.

Staffing and contractor costs related to Program startup activities are estimated at approximately $3.3 million. It is estimated that the Authority would need initial funding (likely in the form of a letter of credit issued by a bank on behalf of the Authority) in the range of $17 million to initiate the Program and provide the working capital needed for service to customers. These figures include working capital related to power purchases that may ultimately be carried by the Program's electric supplier, subject to negotiations during the supplier selection process.

From the date of this plan to the time when the JPA would be in a position to finance its start-up costs, the Cities would need to fund several pre-implementation activities. These include forming and administering the JPA; selecting the program electric suppliers and negotiating the related agreements, regulatory and legal support, and marketing, community and customer outreach. The total of these costs are estimated to range from $500,000 to $750,000, which could be shared among the three cities as mutually agreed upon and later repaid from Program rates. One approach to allocating the costs among the Cities would be to allocate one half of the costs based on each City's relative share of electricity sold and to allocate one half of the costs equally among the Cities as indicated in the following table.[1]

Pre-implementation Costs

City	Low	High
Berkeley	$130,000	$200,000
Emeryville	$105,000	$155,000
Oakland	$265,000	$395,000

2. Phased Customer Enrollment

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

Table 1: Customer Phase-In Schedule

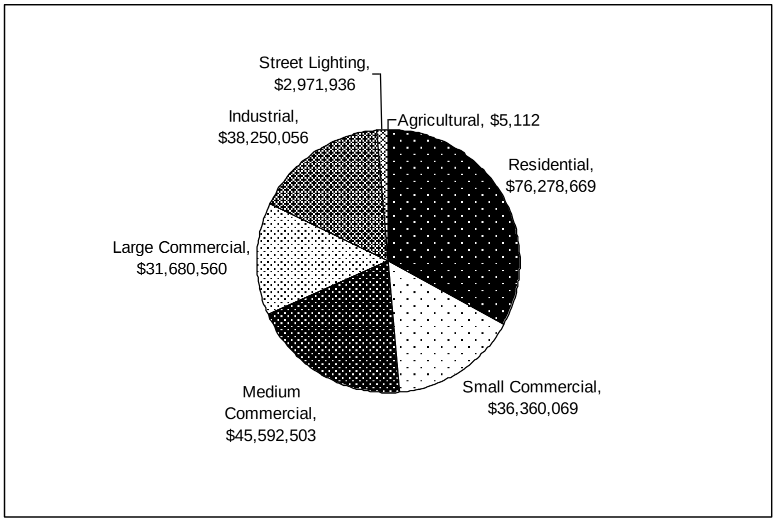
Phase	Start	Eligibility	Customers	Annualized Revenue
Phase 1	January 2010	Municipal Accounts	2,000	$5 Million
Phase 2	May 2010	Commercial and Industrial Accounts	3,000	$120 Million
Phase 3	January 2011	All Others	270,000	$100 Million

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

At full implementation in 2011, the Program is projected to serve approximately 275,000 retail customers and have annual electricity sales of over 2,500 GWh. Annual revenues are projected to be approximately $230 million. The break down of projected sales by major customer class is shown in the following figure.

[1] This allocation method has been used to by the Cities to fund the Cities' share of program development expenses to date.

Figure 2: Projected Retail Electric Sales For 2011[2]



3. Electric Resources

Beginning with the commencement of service to Phase 1 customers in 2010 through about 2015, the Authority would contract with a third party electric supplier under a "full requirements" contract, which places the responsibility for arranging for power to be delivered to Program customers with the supplier. Through this contract the day-to-day responsibility of buying power for the Program are transferred to the third party electric provider, and it is the supplier's responsibility to manage the electric supply for the Program according to the pricing and terms of the negotiated electric supply agreement. This agreement is the primary method for the Authority to manage Program risks during the first several years. The Authority would establish specific renewable energy standards that the supplier must meet. The proposed renewable energy standard begins at 20% of total electric supplies in 2010 and increases to 25% by 2012 and 50% by 2017.

The Authority would plan to develop and finance at least 125 MW of wind resources to be online by 2013.[3] Renewable energy purchases would supplement the Authority's generation to meet the 50% renewable energy objective. In addition, the Authority would promote expanded customer side energy efficiency and demand response programs and target deployment of approximately 27 MW (5% of total demand) of distributed solar within its service area by 2017. A strong preference for local renewable resources and energy efficiency projects will be included in the Authority's energy solicitations.

[2] The sales projections exclude customers currently taking direct access service or customers such as UC Berkeley and the Lawrence Livermore Laboratory, that are otherwise not taking full "bundled" service from PG&E.

[3] The April 2005 Base Case Feasibility Study included greater levels of investment in renewable generation than are contained in this business plan. The investment levels were scaled back due to concerns that higher levels would require a greater level of security for issuance of revenue bonds to finance the resources, which would require greater customer commitments in terms of potential Exit Fees following the initial opt out period.

The clean electric supply portfolio developed by the Authority is expected to result in net reductions in greenhouse gas emissions of between 325,000 to 580,000 metric tons per year by 2017.

4. Rates

The ability to provide increased renewable energy at competitive rates relative to PG&E service would be confirmed during the Program's supplier solicitation process. The goal is to establish rates at or below PG&E's generation rates.[4] Based on best available information, including prices provided by potential Program suppliers and current PG&E rate designs, it is anticipated that the Program's generation rates would initially be approximately 3% higher than the rates charged by PG&E, and the rate premium would be eliminated by 2014. These estimates are highly dependent upon PG&E rates and market prices at the time the Program is ready to be implemented, and it is possible that Program rates could be more or less than projected. The first year projected Program rates are as shown in the following table. ***The following rates are illustrative and subject to change pending selection of an electric supplier and negotiation of the initial power supply contract.***

[4] NCI evaluated whether PG&E rates would be impacted by loss of customers to the Authority's CCA Program and found the impact be a less than 0.5% reduction in the PG&E rate forecast.

Table 2: EBPA Estimated 2010 Program Rates[5]

Customer Class	Program Rates, Generation Only – (Cents Per kWh)
Residential	8.7
Small Commercial	9.6
Medium Commercial	9.4
Medium Industrial	8.7
Large Industrial	8.2
Agricultural	8.9
Street and Area Lighting	8.1

The Authority would establish its rates on an annual basis, as it adopts its budget for the coming year.[6] Program customers would be provided with notices of rate changes and be given the opportunity to comment on proposed rate changes at public workshops and hearings before they are made effective by the Authority's Board of Directors at a duly noticed public meeting.

Customers would be provided with four notices and opportunities to opt-out of the Program without penalty of any kind, twice within 60 days prior to enrollment and twice within the first two months of service. Following the free opt-out period, customers would be allowed to discontinue service subject to payment of a Exit Fee, similar to the fees charged by PG&E for customers that discontinue taking bundled generation service from PG&E. The proposed Exit Fee includes an Administrative Fee ($5 for residential customers) and, if necessary, a Cost Recovery Charge to prevent shifting of costs to remaining Program customers. The Authority's Board would establish the Cost Recovery Charge as part of its ratesetting responsibilities in the case where the costs of the Program's electric supply commitments exceed the prevailing market price for electricity. The Cost Recovery Charge would provide a financial backstop to be used as partial security for financing of the Authority's power supply commitments and as credit support for the electric supply agreement. Additional refinement of the Exit Fee would require input from the Cities' financial advisors, bond counsel and customers for inclusion in the Program's final Implementation Plan. The Authority's Board of Directors would also have the authority to implement entry fees for customers that initially opt out of the Program, but later decide to participate. Entry fees would help prevent potential gaming, particularly by large customers, and aid in resource planning by providing additional control over the Program's customer base. Entry fees would not be practical to administer, nor would they be necessary, for residential and other small customers.

5. Financial Plan

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[5] Includes Energy Cost Recovery Amount component of the Cost Responsibility Surcharge.
[6] The JPA could consider implementing some form of automatic adjustment cost for rates which are subject to pass through.

It is estimated the Authority would need to procure full requirements power supply for the three-year Implementation Period at less than 8.0 cents per kWh to be able to offer rates equal to or below those of PG&E based on current PG&E rate designs. Prices offered in response to the Cities' RFI were slightly higher than this breakeven price, and the Program rates were established at a premium of 3% relative to PG&E's during the three year Implementation Period for purposes of the financial projections. Rate parity during the Implementation Period would require slightly lower power supply prices than those provided in the RFI or slightly higher PG&E rates than projected. Program rates are projected to be at or below PG&E's by 2014 as shown in Appendix D.

A pro forma for the Implementation Period is shown in the following table. For purposes of this financial plan, the term of the initial electric supply contract is assumed to be 2010 – 2015 and include an annual cost escalation factor of 2.5%. Financial projections out to 2025 are contained in Appendix D. ***The figures below are based on indicative price offers and are subject to change following selection of the Program's electric supplier and final negotiations of a power supply contract.***

Table 3: East Bay Power Authority
Summary of CCA Program Implementation
(June 2009 through December 2012)

CATEGORY	2009	2010	2011	2012	TOTAL
I. REVENUES FROM OPERATIONS ($):					
(A) ELECTRICITY SALES:					
RESIDENTIAL	$0	$8,893	$76,278,669	$80,051,567	$156,339,129
GENERAL SERVICE (A-1)	$0	$371,799	$29,657,961	$31,124,904	$61,154,663
SMALL TIME-OF-USE (A-6)	$0	$416,894	$6,702,108	$7,033,608	$14,152,610
ALTERN. RATE FOR MEDIUM USE (A-10)	$0	$32,592,388	$45,592,503	$47,847,600	$126,032,491
500 - 900kW DEMAND (E-19)	$0	$23,129,101	$31,680,560	$33,247,544	$88,057,204
1000 + kW DEMAND (E-20)	$0	$27,597,299	$38,250,056	$40,141,981	$105,989,336
STREET LIGHTING & TRAFFIC CONTROL	$0	$2,949,981	$2,971,936	$3,118,934	$9,040,851
AGRICULTURAL PUMPING	$0	$0	$5,112	$5,365	$10,477
TOTAL REVENUES	$0	$87,066,355	$231,138,904	$242,571,503	$560,776,762
II. COST OF OPERATIONS ($):					
(A) ADMINISTRATIVE & GENERAL (A&G):					
STAFFING	$335,156	$2,104,036	$2,338,987	$2,398,137	$7,176,317
INFRASTRUCTURE	$153,833	$209,500	$184,990	$189,668	$737,992
CONTRACTOR COSTS	$434,833	$1,857,417	$3,108,875	$3,100,235	$8,501,360
IOU FEES (INLCUDING BILLING)	$201,126	$459,445	$2,787,877	$2,475,796	$5,924,243
SUBTOTAL - A&G	$1,124,949	$4,630,398	$8,420,729	$8,163,837	$22,339,912
(B) CCA PROGRAM OPERATIONS:					
ELECTRICITY PROCUREMENT	$0	$71,834,969	$206,977,090	$215,333,790	$494,145,849
EXIT FEES	$0	$2,889,322	$8,075,761	$8,196,898	$19,161,980
FRANCHISE FEES	$0	$663,545	$1,854,632	$1,882,451	$4,400,627
SUBTOTAL - CCA PROGRAM OPERATONS	$0	$75,387,835	$216,907,483	$225,413,139	$517,708,456
(B) OTHER EXPENSES:					
INTEREST	$510,000	$1,020,000	$1,020,000	$1,020,000	$3,570,000
ALLOWANCE FOR UNCOLLECTABLES	$0	$696,531	$1,849,111	$1,940,572	$4,486,214
SUBTOTAL - OTHER EXPENSES	$510,000	$1,716,531	$2,869,111	$2,960,572	$8,056,214
TOTAL COST OF OPERATION	$1,634,949	$81,734,764	$228,197,323	$236,537,547	$548,104,583
CCA PROGRAM SURPLUS / (DEFICIT)	($1,634,949)	$5,331,591	$2,941,581	$6,033,956	$12,672,179

6. Financings

The Authority would need to establish credit in early 2009 sufficient to obtain short term financing, likely a letter of credit, for approximately $3 million to cover Program startup costs and $14 million for working capital. These amounts would be repaid over a five to seven year time horizon. It is anticipated the JPA agreement would state that the financial obligations undertaken by the Authority would not be an obligation of the Cities, unless otherwise agreed to by the Cities. Although it is possible to implement a working line of credit or commercial paper program for startup costs, the risk to investors would most likely require some form of secondary security interest in order to keep the interest rate costs down. This would most likely be in the form of a general fund pledge or through the deposit of reserve funds from the Cities.

The Authority would establish a banking relationship soon after negotiation of the electric supply agreement in order to arrange the necessary startup financing. Up to the point when the Program becomes an independently financeable enterprise, the Cities will need to fund pre-implementation costs estimated to range from $500,000 to $750,000. The Cities may also need to pledge revenues as secondary security for the Authority's startup financing as discussed above.

Financing for the Authority's wind resource would require an approximately $190 million issuance of revenue bonds. This financing would occur once a specific project is completely sited and the CCA Program is fully up and running. The anticipated financial close for the renewable resource project would be fall 2010. The financing would be in the range of a 20 to 30 year term. The debt could be issued by the Authority, or the Authority could enter into a long term power purchase agreement with another public agency that issues the debt. Such arrangements are common among municipal utilities. For example, many publicly owned utilities procure resources through the Northern California Power Agency and the Southern California Public Power Agency, which are joint powers agencies with membership comprised of publicly owned utilities. Any revenue bonds issued by the Authority would stand on their own and would not be liabilities of the Cities.

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

Table 4: Anticipated Program Financings

Proposed Financing	Estimated Amount	Estimated Term	Estimated Issuance
1. Pre-Implementation	$500 - $750 thousand	1 to 2 years	Early 2009
1. Start-Up and Working Capital	$17 million	No longer than 7 years	Mid 2009
2. Renewable Resource Project Financing	$190+ million	20-30 years	Late 2010

7. Implementation Schedule

There are several major steps that would need to be accomplished prior to the initiation of the CCA Program outlined in this business plan. The first major step would be for the Cities to approve a joint powers agreement and to form the JPA. Each city would also need to pass an ordinance, as required by AB 117, declaring the city's intent to file a CCA Implementation Plan through the Authority. The proposed Program will not happen without strong commitment from each of the Cities. Much work remains to be done to make the Program a reality and this will involve additional investments of time by City staff and management. Most importantly, this Program will require that someone step forward to champion the Program both internally within the Cities and externally with potential customers and other stakeholders. Identifying someone to lead this Program should be a high priority and should occur before expending additional funds on Program implementation. It is estimated that approximately $500,000 to $750,000 will be needed for pre-implementation activities listed below, before the Program would be in a position to finance its startup costs:

- Issuance of city ordinances
- Formation of JPA and conduct of meetings
- Communications program and customer outreach
- Selection of and negotiations with suppliers and other contractors
- Legal support
- Regulatory compliance and support

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

Table 5: Timeline for Implementation

ACTIVITY	TIMELINE
Conditional Decision to Proceed (Cities)	June-July, 2008
Authorize JPA and Ordinance	December, 2008
Commencement of the Authority	January, 2009
Issue Supplier Request for Bids	February, 2009
Complete Project Agreement No. 1 (CCA Program)	March, 2009
File Implementation Plan with CPUC	April, 2009
Begin Staffing and Startup Activities	June, 2009
Final Evaluation upon CPUC Certification of Implementation Plan	July, 2009
Execute CCA Project Agreement (PA-1)	July, 2009
Execute Supplier Contract	August, 2009
File Registration Package with CPUC	October, 2009
Finalize Initial Rates	October, 2009
60 Day Notice	November, 2009
Go live phase 1	January, 2010

8. Key Assumptions

Certain key assumptions were made for uncertainties inherent at this stage of Program development. If one or more of these assumptions prove to be incorrect, there could be a material impact on the Program, including the possibility that the Program would be unable to commence service or that it would be unable to provide a higher renewable energy content to customers with rates competitive with PG&E. The key threshold assumptions are as follows:

- There is sufficient market response to the Authority's solicitation of electric supplies, and the market costs of electricity (renewable and non-renewable) do not change significantly relative to PG&E rates from those costs and rates assumed in the plan, before the Authority negotiates the Program electric supply agreement(s);
- The JPA can independently obtain startup financing in the approximate amounts indicated in the plan, or the Cities would be willing to provide a secondary security interest through pledge of general fund revenues or the deposit of reserve funds.
- No significant additions to PG&E's Cost Responsibility Surcharges result from PG&E's electric procurement activities up to the time the CCA commits to beginning program operations that would disproportionately increase these surcharges relative to PG&E's rates.
- The JPA is able to obtain ownership or entitlement to a renewable resource consistent with the operating characteristic and cost assumptions contained in Chapter 3, within approximately four years of Program start-up.
- The JPA successfully issues revenue bonds to finance the renewable resource.
- No lawsuit materially inhibits program implementation.
- A majority of customers to which the Program is offered accepts the Program's rates, terms and conditions, including the Exit Fee provisions discussed in Chapter 5.

CHAPTER 1 – Introduction

Following passage of Assembly Bill 117 in 2002, which created the legal authority for cities and counties to provide electric service through Community Choice Aggregation, the Cities of Berkeley, Emeryville and Oakland each initiated feasibility studies to evaluate the costs and benefits of implementing CCA programs within their respective jurisdictions. Under California law, CCA allows cities, counties, or joint power agencies (JPA's) comprised of cities and/or counties to implement a program to offer to aggregate the electric loads of customers within their jurisdictional boundaries for purposes of electricity procurement. This allows the city/county/JPA (CCA Provider) to make wholesale purchases of electricity on behalf of its constituents, providing an alternative to the incumbent utility.

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

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

A limited feasibility study update was subsequently performed for each city incorporating the recommendations of the peer review team. The results of the updated feasibility studies generally fell within the range of sensitivities contained in the original feasibility studies. The updated analyses did not change the overall conclusions and recommendations contained in the original studies, although the size of the projected benefits declined relative to the original base case results.

Each of the Cities then decided to jointly develop a business plan for implementing a joint CCA program. This business plan outlines a framework for how a CCA program serving Berkeley, Emeryville and Oakland could be organized, governed, operated, and financed. It contains the following sections:

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

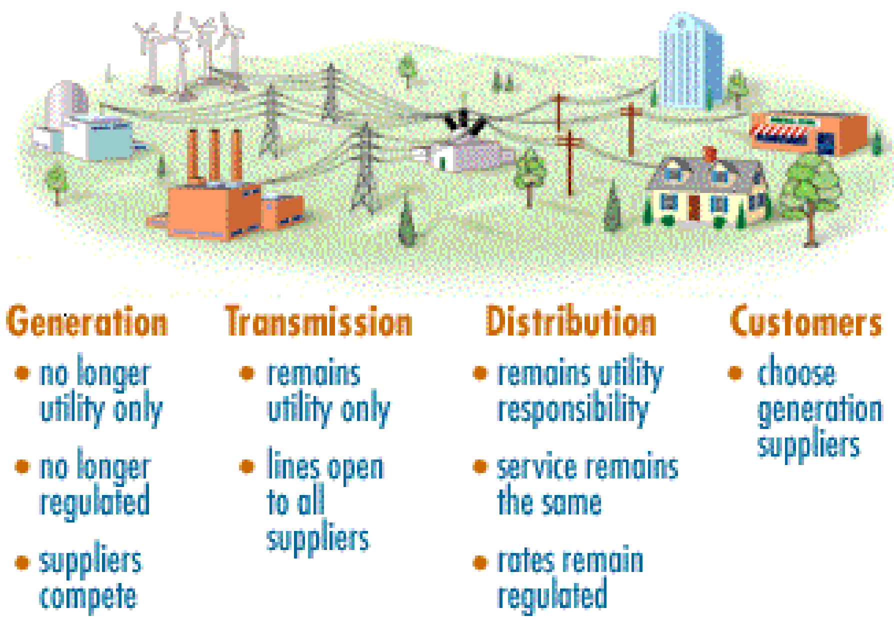
This document represents a comprehensive business plan for the CCA program. It presents proposed plans for organization and governance, ratesetting policies and processes, staffing plans, roles and responsibilities, detailed startup costs and financing, a phased customer enrollment plan, energy efficiency and distributed generation plans, suggested renewable resource technologies and locations for development, Program terms and conditions, and a process for procuring the key third party services needed for Program implementation. The business plan will be subject to much discussion among the city representatives, stakeholders, outside experts and the public before a decision to proceed with developing a formal Implementation Plan can be made. The business plan should also be reviewed by the Cities' financial advisors, and attorneys. This business plan incorporates the electricity prices offered in response to a request for information distributed to potential third party suppliers in January 2007. Using these responses as a starting point, the ability to offer competitive rates under a variety of different market conditions and other variables is addressed in detail in Chapter 4.

Two natural decision points or "off ramps" are built into the business plan. The first occurs when the Cities elect whether to continue with development and filing of a formal Implementation Plan or to terminate their investigation of CCA. The goal is for the Cities to have sufficient information with respect to the likelihood of the Program meeting its renewable energy and rate objectives, assurance that the risks are understood and manageable, and that the plan is financially sound for the Cities to make an informed decision whether to continue. The second decision point occurs after the CPUC certifies the Implementation Plan, and the Cities elect whether or not to continue with actual Program implementation. This second off-ramp is primarily intended to deal with potential regulatory decisions that could materially change the Program.

Background on CCA

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

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



In the current electric marketplace, PG&E owns substantial hydroelectric and nuclear assets and owns or is building 1,350 MW of natural gas-fired generation. PG&E purchases the rest of its electric needs (approximately 60%) from the wholesale marketplace and is the monopoly provider of transmission and distribution services. Under CCA, the customer (i.e. the CCA Provider) chooses the types and amount of generation that it purchases (or owns) for its constituents. The wires (transmission and distribution) continue to be provided by the local monopoly.

PG&E supported AB 117 and is compelled by law to assist local governments in their efforts to establish CCA programs. PG&E has provided all of the information that the participating Cities have requested to date, and has made public comments, with respect to CCA initiatives within California, in which their support and cooperation for potential CCA programs has been affirmed. PG&E has thus far been cooperative in the City's efforts to evaluate CCA. Notwithstanding the public statements claiming to support CCA, PG&E has actively opposed the San Joaquin Valley Power Authority CCA program and has made public statements critical of the proposed CCA program for the City and County of San Francisco. The Cities should anticipate PG&E opposition as the CCA effort proceeds beyond the study stage toward implementation.

CCA Program Components (Implementation Plan Requirements)

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

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

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

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

There are several other cities or potential groups of cities and/or counties around California that are also considering implementing a CCA program. To date there are not any CCA programs operating in California and the CPUC has only recently finalized implementation procedures for a CCA program.[7] The first CCA Implementation Plan in California was submitted by a new joint powers agency, the San Joaquin Valley Power Authority representing municipalities in the greater Fresno area, in January 2007. The CPUC certified the San Joaquin Valley Power Authority's Implementation Plan on May 1, 2007. Much will be learned from the

[7] However, community aggregation programs do exist in other states including Massachusetts, Texas, and Ohio. The Ohio program is very similar to the CCA programs proposed for California.

experiences of this first CCA as it proceeds with its formation and commencement of operations during 2007 and 2008. Other notable CCA efforts include the City and County of San Francisco, the City of Chula Vista, Marin County, and the Cities of Beverly Hills and West Hollywood.

Program Implementation

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

The planned sequence of events showing major steps prior to the CCA program beginning to serve customers is shown in Table 6.

Table 6: Timeline For Implementation

ACTIVITY	TIMELINE
Conditional Decision to Proceed (Cities)	June-July, 2008
Authorize JPA and Ordinance	December, 2008
Commencement of the Authority	January, 2009
Issue Supplier Request for Bids	February, 2009
Complete Project Agreement No. 1 (CCA Program)	March, 2009
File Implementation Plan with CPUC	April, 2009
Begin Staffing and Startup Activities	June, 2009
Final Evaluation upon CPUC Certification of Implementation Plan	July, 2009
Execute CCA Project Agreement (PA-1)	July, 2009
Execute Supplier Contract	August, 2009
File Registration Package with CPUC	October, 2009
Finalize Initial Rates	October, 2009
60 Day Notice	November, 2009
Go live phase 1	January, 2010

CHAPTER 2 – Organizational Plan

This section outlines a proposed organizational plan for the CCA program, including proposed principles for governance of a new joint powers agency that would administer the Program. This section defines the necessary agreements and describes how the Program would be governed, managed, and staffed. A draft Joint Powers Agreement is attached as Appendix A.

Organizational Overview

Pursuant to AB 117, a CCA may be a city, a county, a city and county, or a combination of cities and counties that have elected to jointly implement a CCA program through formation of a joint powers agency ("JPA"). The proposed governance structure for the Program is formation of a new JPA whose governing board would have primary responsibility for managing all aspects of a common CCA program for the Cities. For purposes of this business plan, the new JPA will be referred to as the East Bay Power Authority or simply the "Authority".

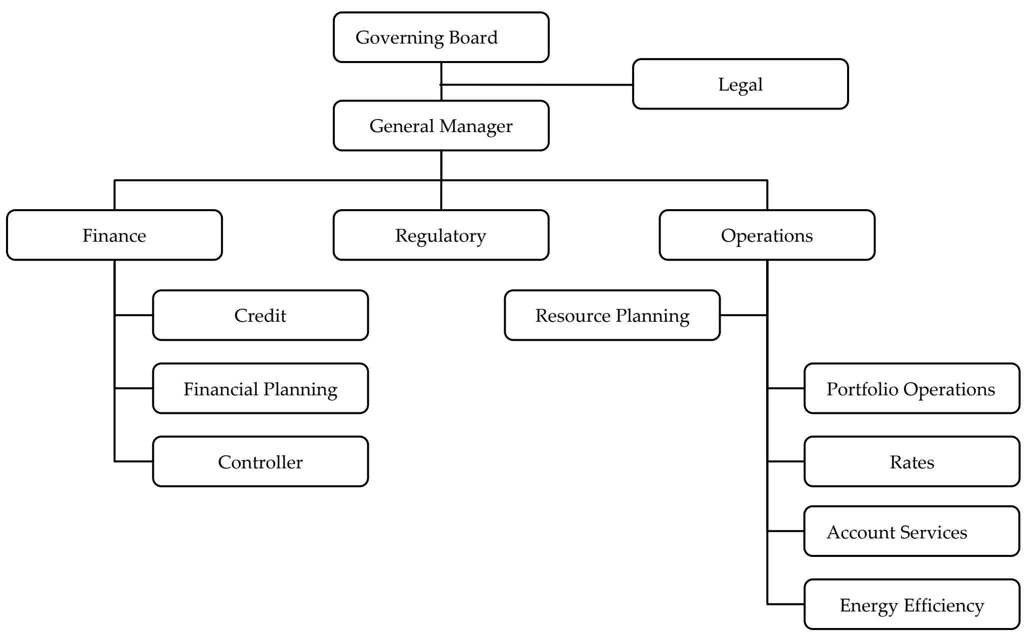
As proposed, the Program would be governed by the Authority's Board of Directors, appointed by the Members. The Authority would be a joint exercise of powers agency formed under California law. Cities that have elected to offer the Program to their constituents would become Members of the Authority. The Authority would be the CCA entity that will register with the CPUC, and it would be responsible for implementing and managing the Program pursuant to the Joint Powers Agreement. The Program would be operated under the direction of a General Manager appointed by the Board of Directors. The General Manager would report to the Authority's Board of Directors comprised of two representatives from each participating Member of the Authority.

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

The Governing Board would also establish a Chairperson and other officers from among its membership and may establish an Executive Committee and other committees and sub-committees as needed to address issues that require greater expertise in particular areas (e.g., finance or contracts). Appendix A contains a draft JPA agreement and proposed principles for establishment of a CCA program agreement. Once the principles are agreed to by representatives of the Cities, a final JPA agreement that defines the terms and conditions by which the Agency will be governed should be developed by qualified legal counsel retained by the Cities.

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

Figure 3: Program Organization



Governance

The ultimate governance provisions of the Authority will require additional discussion among the Cities and will be reflected in the Joint Powers Agreement that should be included with the Implementation Plan. The following governance principles relating to governing board composition and voting provisions, which are reflected in the draft JPA agreement included in Appendix A, have been discussed but not finally agreed to by representatives of the Cities. As proposed, the Authority would have a Board of Directors consisting of two members from each of the Participants. The Board would meet at regular intervals to provide the overall management and guidance for the Authority. All Board meetings would be held in accordance with the Brown Act.

Decisions by the Authority would take place under voting procedures defined in the JPA Agreement. The voting provisions require additional discussion among the Cities. The preliminary proposal is for actions of the Board of Directors to require the affirmative vote of all members present and voting. The exception would be that the Board may take action upon a simple majority vote on matters designated by the Directors representing such majority that urgent or emergency action is needed as defined to fulfill the Authority's obligations under this or other agreements.

Certain decisions of the Board, such as for changes to Program rates or significant resource commitments, would be made following public workshops and hearings. The JPA is a public entity and is required to designate which of the member entities powers it will be governed by.

Officers

The Authority would have a Chair and Vice-Chair elected to one-year terms by the Board of Directors. Both the Chair and Vice-Chair must be members of the Board. In addition, the Authority would have a Secretary, Treasurer, and Auditor; none of which need be members of the Board of Directors. The JPA Agreement will provide further details on each of these positions.

Committees

The Authority may elect to have additional committees or working groups to address various distribution utilities topics. Potential committees include: Resource Committee, Finance/Budget/ Audit Committee, Legal/Regulatory Committee, and Risk Management Committee. Specific committees and their functions would be determined by the Board of Directors at the time of the creation of the committee.

Addition/Termination of Participation

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

A JPA Member would be able to withdraw itself from the JPA subject to the terms and conditions ultimately contained in the JPA Agreement. As proposed, the withdrawing party would need to provide the Authority with reasonable notice of its intent to withdraw, and the withdrawing party would be subject to all reasonable ongoing and past costs incurred by the Authority on behalf of that entity.

Agreements Overview

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

Joint Powers Agreement

The JPA Agreement (enclosed as Appendix A) would create the Authority and delineate a broad set of powers related to the study, promotion, development, and conduct of electricity-related projects and programs. It is anticipated that the Authority would have broad authorities and powers, but a very limited role without implementing agreements ("program agreements") among the members and the JPA to carryout specific programs. The member agencies would designate which member entities' powers the JPA would adopt. This structure is intended to provide flexibility for the Authority to undertake other programs in the future that may be unrelated to CCA on behalf of all or a subset of the Authority's Members. The first program agreement or PA-1, discussed in greater detail below, would provide for the development, implementation and operation of a CCA Program. At the Authority's Members' discretion, future program agreements could provide for other energy related programs. The JPA Agreement specifies the governance provisions of the Authority, which is discussed in greater detail below.

Program Agreement No. 1

PA-1 (draft principles enclosed as Appendix A) would outline the framework for the CCA Program, and transfer the participating Members' authority under AB 117 to the Authority. Approval of PA-1 by a participant would authorize the initiation of the CCA Program for its jurisdiction. It is anticipated that the Cities would consider approval of PA-1 after the CPUC has acted upon the Authority's filed Implementation Plan.

Agency Operations

The Authority would conduct Program operations through its own internal staff and through contracting for services with third parties. The Authority would have its own General Counsel to manage its legal affairs.

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

Resource Planning
The Authority would be charged with developing both short (one and two-year) and long-term resource plans for the Program. The General Manager and staff would develop the resource plan under the guidance provided by the Board and in compliance with California law, and other requirements of California regulatory bodies (CPUC and CEC).

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

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.

- *Demand Side Resource Integration* – integration of energy efficiency, distributed generation and demand response programs with power supply.

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

As the Authority gains experience and begins internalizing more of the functions initially provided by third parties, it will be important for the Authority to approve and adopt a set of *Program Controls* that would 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 risks and such Program Controls will not be necessary at the Authority. Development of Program Controls can take place during the first few years of Program Operations to cover electricity procurement activities that will take place for the period following the term of the initial supply contract.

Energy Efficiency

A key focus of the CCA Program will be the development and implementation of an energy efficiency program for the Authority's Members. A preliminary program is discussed in Chapter 3. The General Manager will be responsible for further development of this Program and it is anticipated that as experience is gained from the retail energy side of the CCA Program, an increased focus on energy efficiency will follow.

The Authority would administer energy efficiency, demand response programs, and distributed (solar) generation that can be used as cost-effective alternatives to procurement of supply-side resources. The Authority will augment its offerings with energy efficiency programs that complement the IOU programs and local government partnerships that are already in place. After operations are stable, the Authority will consider analysis of all energy efficiency programs offered in its territory, including IOU programs.

Rate Setting

The Board of Directors would have the ultimate responsibility for setting the electric generation rates for the Program's customers. The General Manager would be responsible to develop proposed rates and options for the Board to consider before the finalization of the actual rates, subject to the notice requirements and process described in Chapter 5. The final approved rates must, at a minimum, meet the annual revenue requirement developed by General Manager, including any reserves or coverage requirements set forth in bond covenants or the Implementation Plan. The Board will have the flexibility to consider rate adjustments within ranges provided that the overall revenue requirement is achieved; this provides an opportunity for economic development rates or other rate incentives.

Financial Management/Accounting

Managing the overall financial aspects of the CCA Program is expected to be a significant work activity. The General Manager will be responsible for managing this aspect to include developing the 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 Finance function arranges financing for capital projects, prepares financial reports, and ensures sufficient cash flow for the Program. The finance organization plays an important Program risk management function of establishing credit policies that the Program must follow and monitoring the credit of suppliers so that credit risk is managed properly. Credit monitoring is important to keep abreast of changes in a supplier's financial condition and credit rating.

It is planned that the retail settlements (customer billing) would be contracted out to an organization with the necessary infrastructure and capability to handle as many as 275,000 accounts that may enroll in the Program. This function is described under Customer Services, below.

Customer Services

In addition to general Program communications and marketing, a significant amount of customer service and key account representation will be necessary. This will include both a call center for questions and actual routine interaction with customer accounts. The General Manager will be responsible for the Customer Services function. The Authority would contract with a third party service provider for certain billing-related or "Customer Account Services".

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

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

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

Legal and Regulatory Representation

The CCA Program will require ongoing regulatory representation to file resource plans, resource adequacy, compliance with California RPS, and overall representation on issues that will impact the Authority and its Members. The Authority will maintain an active role at the CPUC, CEC, and, as necessary, FERC and the California legislature.

The Authority would also retain other legal services, as necessary, to administer the Authority, review contracts, and provide overall legal support to the activities of the Authority. It is anticipated that legal expenses will be relatively high during the initial years of the Authority due to set up costs, financing and the possibility of PG&E opposition.

Roles and Functions

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

Table 7: Roles and Functions

Organization	Roles/Functions/Activities
Authority 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*

Organization	***Roles/Functions/Activities***
	Resource Planning - *Load research* - *Load forecasting* - *Supply-side/Demand side portfolio planning*
	Contract Management – RFP/RFQ
	Customer Service - *Account representatives*
Energy Supplier	*Supply Operations* - *Procurement* - *Scheduling coordination* - *Settlements (ISO/Wholesale)* - *Short-term load forecasting*
Customer Account Services Provider/Data Manager	*Account Management (Customer Information System)* - *Customer switching* - *New customer processing* - *Data exchange (EDI)* - *Payment processing (AR/AP)* - *Billing and retail settlements* - *Call center*

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

Staffing

Staffing requirements for the above Authority functions are approximately tweny 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 contractors. The "staff" functions could be performed by full time employees of the Authority, contract employees, or contracted out to third parties (e.g. legal, accounting, consulting or utility companies). Ultimately, the General Manager should make the determination on appropriate staffing decisions. However, the staffing estimates and associated costs presented here reflect reasonable assumptions for planning purposes.

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

Table 8: Expectations for Staffing Roles

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

Staff would be added incrementally to match workloads involved in forming the new organization, managing contracts, and initiating customer outreach/marketing during the pre-operations period. During the pre-startup period, minimal staffing requirements would include a Program Manager and a Sales and Marketing Manager, with administrative support (2.5 full time equivalent positions). Additional staff would be added during the Phase 1 customer enrollment period and following commencement of service to Phase 1 customers. The organization should make sure it is nearly fully staffed before the Phase 2 customers are enrolled. Phase 2 contains the key commercial and industrial customer segments, the largest of which would have assigned customer account representatives.

Table 9 provides an estimate of the appropriate staff additions that the Authority would require for 2009 – 2010 to implement and operate the CCA Program. Actual staff will be dependent upon several factors including the ability to recruit and hire qualified staff and personnel policies ultimately established by the Board of Directors and administered by the General Manger.

Table 9: Internal Staffing Cost Estimates

Staffing Plan (FTEs)	Pre-Startup					Enrollment 1 – Pilot Phase		Cutover 1	Phase 1 Operations		Notification and Enrollment Period		Cutover 2
Staff	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**
Management													
Manager	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Contract Analyst	-	-	-	-	-	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Administrative Assistant	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Finance and Rates													
Manager	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Rates Analyst	-	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0
Accounting/Billing Analyst	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Administrative Assistant	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales And Marketing													
Manager	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Account Representatives	-	-	-	-	-	-	-	-	-	3.0	4.0	4.0	4.0
Communications Specialist	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0
Administrative Assistant	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0
Regulatory													
Regulatory Manager							1.0	1.0	1.0	1.0	1.0	1.0	1.0
Regulatory Analyst	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Information Technology													
IT Specialist	-	-	-	-	-	-	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Human Resources													
HR Specialist	-	-	-	-	-	0.5	0.5	0.5	1.0	1.0	1.0	1.0	1.0
Subtotal Staffing	2.5	2.5	2.5	2.5	2.5	6.0	11.0	11.0	12.5	16.5	18.5	18.5	18.5

The table below shows the staffing plan for the Authority at initial full-scale operational levels (Phase 3). Customer service for the mass market residential and small commercial customers will be provided by the Program's third party customer account services provider. The modest staff additions required for Phase 3 would primarily be engaged in managing and validating the retail settlements performed by the Program's account services contractor.

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

Position	Staff (Full Time Equivalents)
Management	
Program Manager	1.0
Contract Analyst	2.0
Administrative Assistant	0.5
Finance and Rates	
Manager	1.0
Rates Analyst	1.0
Accounting/Billing Analyst	2.0
Administrative Assistant	0.5
Sales and Marketing	
Manager	1.0
Account Representative	4.0
Communications Specialist	1.0
Administrative Assistant	1.0
Regulatory	
Regulatory Manager	1.0
Regulatory Analyst	2.0
Information Technology	
IT Specialist	1.0
Human Resources	
HR Specialist	1.0
Total Staffing	20.0

Longer term staffing needs will include energy efficiency and administration of other demand side programs and potentially the creation of an internal organization to perform the portfolio operations and account services functions that will originally be contracted out. Early energy efficiency efforts will be primarily contracted out.

CHAPTER 3 - LOAD FORECAST AND RESOURCE PLAN

Introduction

This Chapter describes the Authority's ten year integrated resource plan, which strives to create a clean, diversified portfolio of electricity supplies capable of meeting the electric demands of the Authority's retail customers, plus sufficient reliability reserves. This plan reflects a significant commitment to renewable resources to meet at least one half of the electric needs of the participating East Bay Cities through new, renewable resources by 2017. The resource plan sets a course for the Authority to invest in new wind power generation and for significant purchases of renewable energy from third party suppliers. The resource plan also sets forth aggressive targets for improving customer side energy efficiency as well as plans for facilitating deployment of more than 25 MW of new distributed solar within the East Bay by 2017. A strong preference for local renewable resources and energy efficiency projects will be included in the Authority's energy solicitations.

Successful execution of the plan described in this section would accomplish the following by 2017:

- Use renewable energy to supply 50% of the electricity used in the area.
- Achieve incremental reductions in greenhouse gas emissions ranging from 325,000 to 580,000 metric tons per year.
- Invest in 125 MW of new wind generation capacity.
- Purchase additional renewable energy (wind, geothermal, biomass and solar) to achieve a net increase of approximately 250 MW of renewable energy relative to continued service from PG&E.
- Deploy an additional 27 MW of distributed solar in the area.
- Transfer the operational and pricing risks of managing the supply portfolio to a third party electric supplier for at least the first three to seven years of Program operations.

As a Community Choice Aggregator, the Authority would be responsible to arrange for the scheduling of sufficient electric supplies to meet the hour-by-hour demands of its customers. The Authority would also need to adhere to capacity reserve requirements established by the CPUC and the CAISO designed to address uncertainty in load forecasts and potential supply disruptions caused by generator outages and/or transmission contingencies. In addition, the Authority would be responsible for ensuring that its resource mix contains sufficient production from renewable energy resources needed to comply with the statewide renewable portfolio standards. This resource plan meets or exceeds all of the applicable regulatory requirements related to resource adequacy and the renewable portfolio standard.

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

1. Participant Accounts
2. Commercial and Industrial Accounts
3. All Remaining Accounts

This approach provides the Authority with the ability to start slow, address any problems or unforeseen challenges on a small manageable program before gradually building to full Program integration for an expected 275,000 plus customer base.[8] This approach also provides for the Authority and its primary contractors to address all system requirements (billing, collections, payments) under a phase-in approach to minimize potential exposure to uncertainty and financial risk by "crawling" prior to attempting to walk and ultimately run.

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

Phase 1 will consist solely of the direct electric accounts of the Program Participants' (Member City) loads. Under this approach it expected that the opt-out rate for accounts (and load) for the Cities will be zero percent. This would result in approximately 2,000 accounts representing a load of 70 GWh annually. Energy supply for Phase 1 would be met via agreements entered into by the Authority with third-party energy service providers.

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

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[8] The sales projections exclude customers currently taking direct access service or customers such as UC Berkeley and the Lawrence Livermore Laboratory, that are otherwise not taking full "bundled" service from PG&E.

Phase 2 of the Program is focused on medium and large electric users; those accounts that typically have demands in excess of 50 kW, in addition to the customers already included in Phase 1.[9] For modeling purposes it is assumed that 10 percent of bundled service customers will opt-out of the CCA Program and that all of the direct access customers will opt-out. This provides for an estimated incremental Phase 2 customer class of approximately 3,400, with an annual load of 1,500 GWh.

Phase 3 – All Accounts

The final Phase (Phase 3) provides for all electric customers within the service territory of the Authority's Participating Members to have the option of participating in the CCA Program. Again an opt-out rate of 10 percent of the bundled service customers and 100% of direct access customers is assumed. However, this represents a significant increase in the number of customers and the overall energy requirements for the Program as the incremental growth for Phase 3 is 270,000 customers and 1,200 annual GWh.

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

Resource Plan Overview

Several criteria were used to guide development of the Authority's resource plan. The proposed supply portfolio strives to achieve the following attributes:

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

To meet these objectives and the applicable regulatory requirements, the Authority's resource plan includes a diverse mix of generation, power purchases, renewable energy, new energy efficiency programs, demand response, and distributed generation. The Authority's diversified resource plan minimizes risk and volatility that can occur from over-reliance on a single resource type or fuel source. The ultimate goal of the Authority's resource plan is to source one half of the resource mix from renewable resources by 2017, which would more than double the renewable energy targets of PG&E under the renewable portfolio standards.

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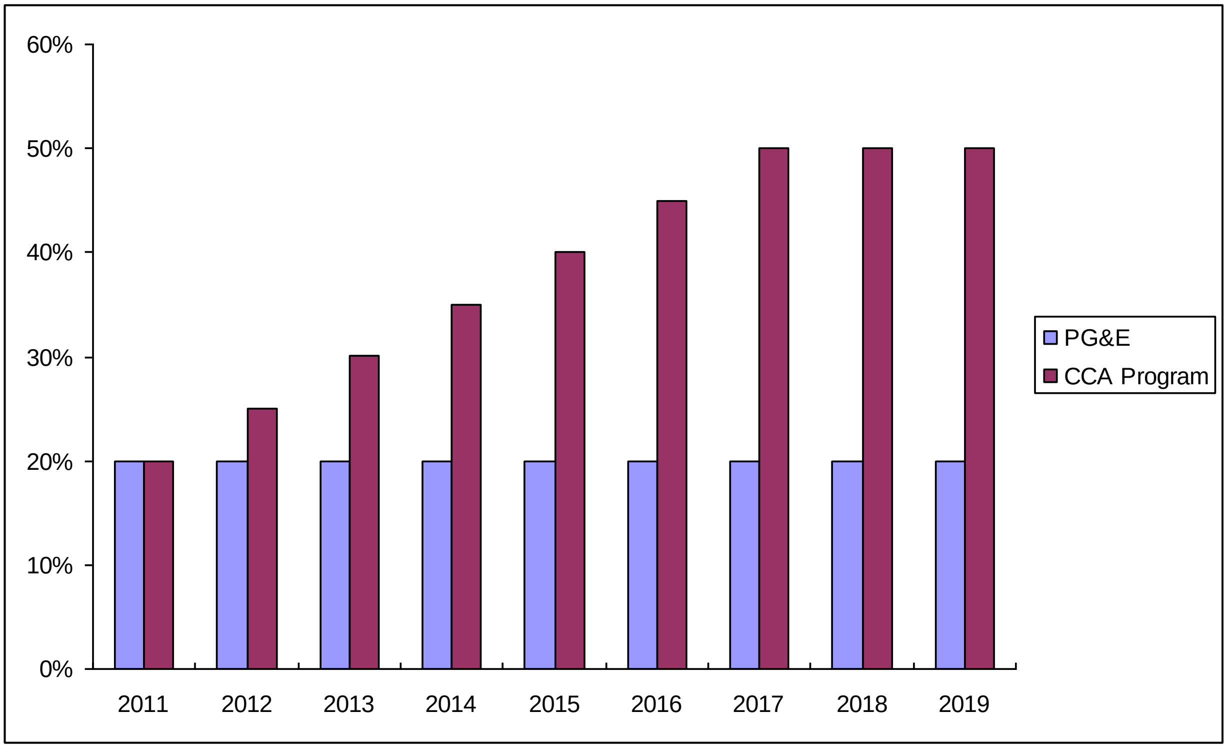
[9] Eligibility for the various phases will be determined based on the rate schedule the account takes service under, not by kW size.

Figure 4: Comparison of Renewable Energy Plans



The planned resource mix is comprised primarily of power purchases from third party electric suppliers and also includes renewable generation assets (likely a wind resource) owned by the Authority.

The Authority's renewable generation would provide a portion of the Authority's electricity requirements on a cost-of-service basis, which is more cost-effective than purchasing renewable energy from third party developers. As discussed in Chapter 4, the amount of generation proposed to be financed by the Authority is constrained by security requirements necessary for issuance of revenue bonds needed to finance the project. Once the Program demonstrates it can operate successfully for a number of years, additional generation investments would be expected. Additional refinement of security requirements in consultation with the Cities' financial advisors, investment bankers, attorneys, and potentially with customer input may increase the assumed debt carrying capacity of the Program and enable greater investment than shown in this plan.

The Authority's resource plan will integrate supply-side resources with programs that will help customers reduce their energy costs through improved energy efficiency and other demand-side measures. As part of its integrated resource plan, the Authority would actively pursue, promote and administer a variety of customer energy efficiency programs that can cost-effectively displace supply-side resources. Included in this plan is a goal to promote the deployment of over 25 MW of distributed solar by 2017.

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

Table 11: Energy Balance

East Bay Power Authority
Energy Balance
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EBPA Demand (GWh)										
Retail Demand	-909	-2,540	-2,578	-2,616	-2,656	-2,695	-2,736	-2,777	-2,819	-2,861
Distributed Generation	16	20	24	28	32	36	37	40	41	42
Energy Efficiency	0	2	5	6	6	6	7	7	7	7
Losses	-62	-176	-178	-181	-183	-186	-188	-191	-194	-197
Total Demand	-955	-2,694	-2,727	-2,763	-2,800	-2,838	-2,881	-2,921	-2,965	-3,009
EBPA Supply (GWh)										
Renewable Resources										
Generation	0	0	0	322	322	322	322	322	322	322
Power Purchase Contracts	179	504	637	453	594	739	890	1,043	1,063	1,084
Total Renewable Resources	179	504	637	775	916	1,061	1,212	1,365	1,385	1,406
Conventional Resources										
Generation	0	0	0	0	0	0	0	0	0	0
Power Purchase Contracts	776	2,191	2,090	1,988	1,884	1,777	1,669	1,556	1,579	1,603
Total Conventional Resources	776	2,191	2,090	1,988	1,884	1,777	1,669	1,556	1,579	1,603
Total Supply	955	2,694	2,727	2,763	2,800	2,838	2,881	2,921	2,965	3,009

Table 12: Capacity Balance

East Bay Power Authority

Capacity Balance
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EBPA Demand (MW)										
Retail Demand	225	430	437	443	450	457	463	470	477	485
Distributed Generation	(11)	(14)	(16)	(19)	(22)	(24)	(25)	(27)	(28)	(28)
Energy Efficiency	-	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Losses	15	29	29	30	30	30	31	31	31	32
Total Net Peak Demand	230	446	449	453	457	461	468	473	480	487
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	34	67	67	68	69	69	70	71	72	73
Capacity Requirement Including Reserve	264	512	516	520	525	530	538	544	552	560
EBPA Supply (MW)										
Renewable Resources										
Agency Resources	0	0	0	125	125	125	125	125	125	125
Firm Power Purchase Contracts	20	57	73	52	68	84	102	119	121	124
Total Renewable Resources	20	57	73	177	193	209	227	244	246	249
Conventional Resources										
Agency Resources	-	0	0	0	0	0	0	0	0	0
Power Purchase Contracts	200	345	332	320	308	295	284	271	275	279
Planning Reserve Contracts										
Other Capacity Contracts	34	67	67	68	69	69	70	71	72	73
Total Conventional Resources	234	411	400	388	376	364	354	342	347	352
Demand Side Resources Treated As Supply	0	26	26	26	26	27	27	27	28	28
Reserve Support	9	18	18	18	18	18	19	19	19	19
Maintenance Outages and Limitations	-	-	-	(88)	(88)	(88)	(88)	(88)	(88)	(88)
Supply After Maintenance Outages And Limitations	264	512	516	520	525	530	538	544	552	560

Supply Requirements

The starting point for the Authority's resource plan is a projection of participating customers and associated electric consumption. Projected electric consumption is evaluated on an hourly basis, and matched with resources best suited to serving the aggregate of hourly demands or the Program's "load profile". The electric sales forecast and load profile will be affected by the Authority's plan to introduce the Program to customers in phases and the degree to which customers choose to remain with PG&E during the customer enrollment and opt-out period. The Authority's phased roll-out plan and assumptions regarding customer participation rates are discussed below.

Customer Participation Rates

Customers will be automatically enrolled in the Authority's electricity Program unless they opt-out during the customer notification process conducted during the 60-day period prior to enrollment and continuing through the 60-day period following commencement of service. The Authority anticipates an overall customer participation rate of 100 percent (excluding direct access customers) during Phase 1, when service is being offered to the service accounts that are affiliated with the Authority's participating members. Participation rates are expected to be 90 percent (excluding direct access customers) during Phases 2 through 3 based on experience with similar opt-out style municipal aggregation programs developed in other states; these have ranged from 5 percent in Massachusetts to 10 percent in Ohio. The participation rate would not expected to vary significantly among customer classes if the Authority is able to offer competitive and stable rates relative to PG&E. However, if actual Program rates are higher, or if the CPUC allows PG&E to engage in its own marketing to customers, the opt-out rates would likely increase. The assumed participation rates should be refined as the Authority's marketing and communications plan is executed and experience is gained by other California CCA programs. The sensitivity analysis presented in Chapter 4 addresses the impact on Program economics under various opt out rates for the respective customer classes.

Customer Forecast

Once customers enroll in each implementation phase, they will be switched over to service by the Authority on their regularly scheduled meter read date over an approximately thirty day period. Approximately 70 service accounts per day will be switched over during the first month of service. Enrollments planned for Phase 2 will be relatively few in number; however, during Phase 3, the Authority's customer account systems must be capable of processing customer enrollments of over 9,000 accounts per day. The number of accounts served by the Authority at the end of each phase is shown in the table below.

Table 13: Customer Enrollments

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

EBPA Customers	Jan-10	May-10	Jan-11
Residential	17	17	252,439
Small Commercial	1,052	1,052	20,279
Medium Commercial	59	2,561	2,600
Large Commercial	11	385	391
Industrial	-	51	51
Street Lighting & Traffic	793	793	1,106
Ag & Pump.	-	-	3
Total	1,932	4,859	276,869
Customer Additions	1,932	2,927	272,010

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

Table 14: Customer Projections

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

EBPA Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	17	252,439	256,226	260,069	263,970	267,930	271,948	276,028	280,168	284,371
Small Commercial	1,052	20,279	20,583	20,892	21,205	21,523	21,846	22,174	22,507	22,844
Medium Commercial	2,561	2,600	2,639	2,679	2,719	2,760	2,801	2,843	2,886	2,929
Large Commercial	385	391	397	403	409	415	421	428	434	440
Industrial	51	51	52	53	53	54	55	56	57	57
Street Lighting & Traffic	793	1,106	1,123	1,139	1,157	1,174	1,191	1,209	1,227	1,246
Ag & Pump.	-	3	3	3	3	3	3	3	3	3
Total	4,859	276,869	281,022	285,237	289,516	293,859	298,267	302,741	307,282	311,891

Sales Forecast

The Authority's forecast of kWh sales reflects the roll-out and customer enrollment schedule shown above. The annual electricity needed to serve the Authority's retail customers increases from just less than 1,000 GWh in 2010 to nearly 2,700 GWh at full roll-out in 2011. Annual energy requirements are shown below. Customers and electricity sales are expected to increase by an average of 1.5% per year after the customer phase-in period is complete, reflecting relatively modest increases in energy consumption expected for the Bay Area as well as the impacts of expanded energy efficiency spending by PG&E. Actual sales will depend in part on the success of the program during the initial phases. Long term sales and customer forecasts would be refined following the initial opt-out period and updated on a regular basis.

Table 15: Energy Projections

East Bay Power Authority
Energy Requirements
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EBPA Demand (GWh)										
Retail Demand	909	2,540	2,578	2,616	2,656	2,695	2,736	2,777	2,819	2,861
Distributed Generation	-16	-20	-24	-28	-32	-36	-37	-40	-41	-42
Energy Efficiency	0	-2	-5	-6	-6	-6	-7	-7	-7	-7
Losses	62	176	178	181	183	186	188	191	194	197
Total Load Requirement	955	2,694	2,727	2,763	2,800	2,838	2,881	2,921	2,965	3,009

Capacity Requirements

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

A portion of the Authority's capacity requirements must be procured locally, from the Greater Bay area as defined by the CAISO. Current regulations also require the Authority to procure resources from within the other local resource area in PG&E's service area ("Other PG&E"), despite the fact that the Authority would not serve load outside of the Greater Bay area. The Authority would be required to demonstrate its local capacity requirement for each month of the following calendar year. The local capacity requirement is a percentage of the total (PG&E service area) local capacity requirements adopted by the CPUC based on the Authority's forecasted peak load. The formula is as follows:

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

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

The waiver applies to Commission-imposed penalties only. If deficient, the Authority would be responsible for any applicable backstop procurement costs even if it received a waiver from penalties. The CAISO would procure local capacity as a backstop and would charge a fee based on its costs of procuring the capacity. For 2007, the backstop cost was approximately $73 per kW-year. A request for waiver is not anticipated based on discussions with potential electricity suppliers. Each of the suppliers responding to the Cities' request for information provided estimated pricing for resource adequacy (local and system) capacity well below the administratively determined price described above.

The Authority's first resource adequacy filing could take place as early as October 2009, according to the schedule established by the CEC for evaluating statewide resource adequacy based on resource plans filed by all load serving entities in the state. The forward resource adequacy requirements for 2010 and 2011 are shown in the following table.

Table 16: Monthly Capacity Requirements

East Bay Power Authority
Summer Peak Loads
(MW)
2010 to 2012

Month	2010	2011	2012
January	12	408	411
February	14	446	449
March	13	371	373
April	13	384	386
May	209	372	375
June	216	399	402
July	205	388	390
August	209	428	431
September	230	419	421
October	212	396	399
November	214	426	429
December	193	409	412

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

Month	2010	2011	2012
January	14	469	472
February	16	512	516
March	15	426	429
April	15	442	444
May	240	428	431
June	249	459	462
July	236	446	449
August	240	492	495
September	264	481	485
October	244	456	459
November	246	490	494
December	222	470	474

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

Table 17: Annual Capacity Requirements

East Bay Power Authority
Capacity Requirements
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SJVPA Demand (MW)										
Retail Demand	225	430	437	443	450	457	463	470	477	485
Distributed Generation	(11)	(14)	(16)	(19)	(22)	(24)	(25)	(27)	(28)	(28)
Energy Efficiency	-	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Losses	15	29	29	30	30	30	31	31	31	32
Total Net Peak Demand	230	446	449	453	457	461	468	473	480	487
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	34	67	67	68	69	69	70	71	72	73
Capacity Requirement Including Reserve	264	512	516	520	525	530	538	544	552	560

Local capacity requirements are a function of the PG&E area resource adequacy requirements and the Authority's projected peak demand. The Authority would need to work with the CPUC's Energy Division and staff at the California Energy Commission to obtain the data necessary to calculate the Authority's monthly local capacity requirement. A preliminary estimate of the Authority's annual local capacity requirement for the Greater Bay Area and the Other PG&E Area is estimated to be approximately 200 MW in 2011 as shown in the following table.

Table 18: Local Capacity Requirements

East Bay Power Authority
Local Capacity Requirements
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PG&E Planning Area System Peak (MW)	22,717	23,012	23,311	23,614	23,921	24,232	24,547	24,866	25,189	25,517
Total Capacity Requirement (115%)	26,124	26,464	26,808	27,156	27,509	27,867	28,229	28,596	28,968	29,344
Authority Peak (MW)	230	446	449	453	457	461	468	473	480	487
Authority Share of Planning Area	0.9%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
Local Capacity Requirement - Greater Bay Area	4,959	5,024	5,089	5,155	5,222	5,290	5,359	5,429	5,499	5,571
Local Capacity Requirement - Other PG&E	6,313	6,395	6,478	6,562	6,648	6,734	6,822	6,910	7,000	7,091
Authority Local Capacity Requirement Greater Bay	44	85	85	86	87	88	89	90	91	92
Authority Local Capacity Requirement Other PG&E	55	108	108	109	110	111	113	114	116	118

Renewable Portfolio Standards Energy Requirements

Basic RPS Requirements

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

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

RPS Compliance Rules

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

The CPUC's flexible compliance rules articulated in D.03-06-071 allow a load serving entity to defer up to 25 percent of the IPT without explanation, as long as the shortfall is made up within three years. Shortfalls greater than 25 percent of IPT will be permitted upon demonstration of one or more of the following: 1) insufficient response to a request-for-offers; 2) contracts in hand that will make up the deficit in future years; 3) inadequate public goods funds to cover above market renewable contract costs; and 4) seller non-performance. Flexible compliance does not currently extend the 20 percent by 2010 requirement. Noncompliance will result in penalties of 5 cents per kWh, capped at $25 million per year.

The Authority's Renewable Energy Goals

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

Table 19: Renewable Portfolio Standards Requirements

East Bay Power Authority
RPS Requirements
(MWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales	892,505	2,517,867	2,548,793	2,581,864	2,616,992	2,652,708	2,692,467	2,729,729	2,770,674	2,812,235
Baseline	-	-	178,501	503,573	509,759	516,373	523,398	530,542	538,493	545,946
Incremental Procurement Target	-	178,501	325,072	6,185	6,614	7,026	7,143	7,952	7,452	8,189
Annual Procurement Target	-	178,501	503,573	509,759	516,373	523,398	530,542	538,493	545,946	554,135
% of Current Year Retail Sales		7%	20%	20%	20%	20%	20%	20%	20%	20%

The Authority targets would match or exceed PG&E's renewable energy percentage from the first day of its operations and then exceed the RPS as the Authority incrementally builds towards the 50% goal by 2017. The Authority would therefore significantly exceed the minimum RPS requirements as shown below; provided that the competitive wholesale market provides qualified responses to the Authority's resource solicitations.

Table 20: Renewable Energy Targets In Excess of RPS

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales (MWh)	892,505	2,517,867	2,548,793	2,581,864	2,616,992	2,652,708	2,692,467	2,729,729	2,770,674	2,812,235
Annual RPS Target (Minimum MWh)	-	178,501	503,573	509,759	516,373	523,398	530,542	538,493	545,946	554,135
Program Target (% of Retail Sales)	20%	20%	25%	30%	35%	40%	45%	50%	50%	50%
Program Renewable Target (MWh)	**178,501**	**503,573**	**637,198**	**774,559**	**915,947**	**1,061,083**	**1,211,610**	**1,364,864**	**1,385,337**	**1,406,117**
Surplus In Excess of RPS (MWh)	**178,501**	**325,072**	**133,625**	**264,800**	**399,575**	**537,685**	**681,069**	**826,371**	**839,392**	**851,982**
Annual Increase (MWh)	178,501	325,072	133,625	137,361	141,388	145,136	150,527	153,254	20,473	20,780

Resources

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

The Authority's resource plan anticipates the development of a wind generation resource within the PG&E service area planned to be online by 2013. While this is a reasonable timeline for the Authority to negotiate acquisition of such a project, it should be understood that the actual online date could be delayed. Wind energy was selected for the basis of this plan due to its relative abundance and low cost; however, other renewable technologies would be considered once the Authority begins its resource acquisition program. The plan calls for initial development of 125 MW of wind resources to meet approximately 10% of the Authority's annual electricity requirements, with additional investments likely once the Program has demonstrated a proven track record. Approximately 40% of the total resource mix is anticipated to come from power purchases from third party renewable energy developers. Non-renewable baseload, peaking and shoulder load requirements would generally be met with power purchase contracts for the balance of this planning horizon.

The planned resource mix for 2011 and 2018 are shown in the following figures.

Figure 5: Resource Mix in 2011

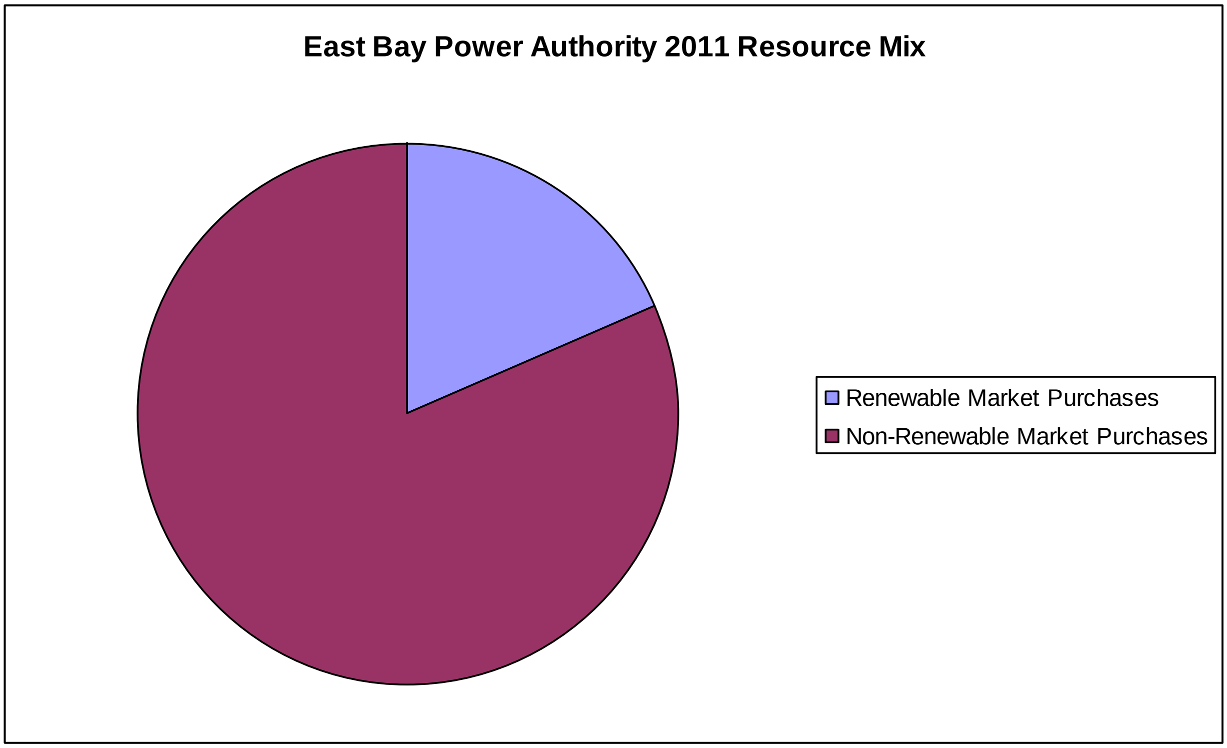
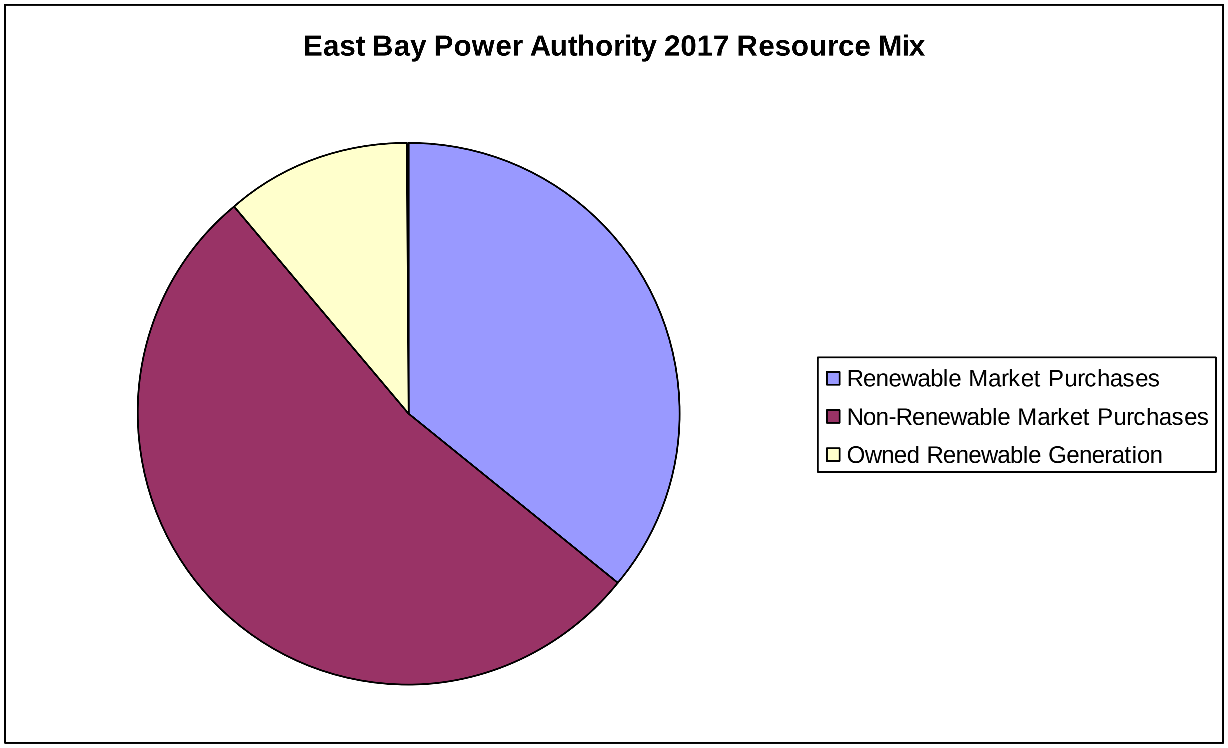


Figure 6: Resource Mix in 2017



Purchased Power

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

Initially, the Program's third party electric supplier will be responsible for managing the overall supply portfolio. Details of the electric supply portfolio and risk management practices that will be employed by the Program's electric supplier will be established as the contract is negotiated with the selected electric supplier. It is anticipated that a mix of short and long term power purchases will be used to meet the hour-by-hour demand requirements of the Authority's customers. The Authority's power supply may come from a mix of standardized contracts for electricity during peak (6 X 16), super-peak (5 X 8), and base load (7 X 24) hours.

Non-standard products may also be utilized to provide for shaped energy, load following and balancing services.

Contracts of various lengths and pricing terms will be explored during negotiations with suppliers in order to hedge price risk and avoid exposure to adverse market conditions along the time horizon. The Authority's resource plan defines three time horizons to categorize the timeframes in which supply contract terms are grouped:

Table 21: Contract Time Horizons

Time Horizon	Length
Short-term	1 to 3 years
Medium-term	3 to 5 years
Long-term	5 to 10 years

The proportion of contracts or volumes falling into each time horizon will reflect market conditions at any point in time. Specific price hedges can be executed as supply contracts are negotiated and the mix may be adjusted frequently to optimize the supply portfolio and adhere to risk management policies established by the Authority. For planning purposes, the Authority anticipates the following initial price hedging guidelines for its power purchase contracts over the longer term (i.e., the period following the initial full requirements contract):

Table 22: Price Hedging Guidelines

Time Horizon	Percentage of Portfolio
Short-term	20-25%
Medium-term	15-20%
Long-term	10-15%

The remainder of the portfolio can be supplied by index priced (variable), load following electricity products.

Renewable Resources

To meet its aggressive renewable energy goals, the Authority would secure power purchase contracts for qualified renewable energy resources, quickly ramping up to approximately 635,000 MWh by 2012. To qualify as eligible for California's RPS, a generation facility must use one or more of the following renewable resources or fuels:

- Biomass

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

Renewable technologies that are predominant and generally commercially available are wind, geothermal, biomass, land fill gas, and solar (concentrating solar or photovoltaic). Studies sponsored by the CEC show 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.[10] The vast majority of the resource potential identified by the CEC is located in Southern California and concentrated in four areas: Tehachapi area and Riverside County wind resources (2,800 MW), utility-scale solar in the Southern California deserts (1,000 MW), and geothermal in the Imperial Valley (1,600 MW). There are an estimated 450 MW of resources in the PG&E territory economically developable by 2010, primarily represented by wind resources in Solano and Alameda Counties (400 MW) and geothermal (45 MW) near the Geysers.

The costs of renewable energy vary significantly from project to project, depending upon location, technology, available incentives, and other factors. Typical power purchase costs for qualifying renewable energy are from 1 to 2 cents per kWh higher than non-renewable power, or approximately 8 to 10 cents per kWh in the current market, including current subsidies.[11] The cost of large scale solar energy is typically higher, ranging from 12 to 15 cents per kWh, but solar also has higher value due to its production during peak use periods. These costs have risen dramatically in recent years as have the costs of natural gas fueled generation. The Authority's resource plan would be updated frequently to take account of changes in resource costs and availability.

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

[11] Current subsidies include the production tax credit for wind and other qualifying renewable resources and the solar investment tax credit. Non taxpaying entities such as a CCA may take advantage of the Renewable Energy Production Incentive, which is equivalent to the production tax credit.

Ideally, the Authority will be able to procure renewable energy locally, or at least from within the PG&E service area, and a strong preference for local resources will be included in any renewable energy solicitation. Transmission capacity for energy imports from outside the host utility service area (PG&E) is available during only certain times of the year, and electricity transmitted from points outside of the region would be subject to potential charges for use of congested transmission lines. Congestion charges will become a more significant economic factor as the CAISO transitions from the current zonal congestion pricing model to a nodal model as it implements its Market Redesign and Technology Update (MRTU) in 2008.[12] The ideal energy source would be located within the region, 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.

Near Term Renewable Potential

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

Table 23: 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[13]
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**

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

[13] 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.

Source: Community Choice Aggregation Demonstration Project; Renewable Resource Development Roadmap; Navigant Consulting, Inc, June 2006.

The RPS needs of the existing California utilities exceed the amount of new resource potential that can be developed with little or no transmission development, leading to current efforts by the IOUs and municipal utilities to build new transmission to access new markets. Considering that PG&E is expected to need over 6.5 million MWh per year of additional renewable energy procurement to meet its RPS obligation by 2010, the Authority may need to procure renewable energy from outside the area or possibly 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.[14] This is not to say that renewable resources would necessarily be unavailable to the Authority in the near term; the Authority's needs are modest relative to those of the IOUs, and not all renewable resources are bid into the IOU's requests for offers. The Program can also seek to contract with existing renewable resources (Qualifying Facilities) that will be coming off of contracts with the IOUs, until new resources and transmission can be developed.

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

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

Medium And Long Term Renewable Potential

In the medium to long term, the Program will be able to utilize the transmission expansion projects that are underway by PG&E and SCE, designed to expand access to renewable resource areas. PG&E 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).[15] 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 April 2007, over 26,000 MW of renewable resources had applied for transmission

[14] The cost of potential congestion charges has been included in the risk analysis presented in Chapter 4.

[15] 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.

interconnections with the CAISO. The list of projects currently in the CAISO "queue", summarized by resource type, is contained in Appendix B. According to the CAISO, about one half of all projects in the queue ultimately are developed. The projects listed in Appendix B represent proposed renewable projects that the Authority could potentially use to meet its renewable energy requirements, once the necessary transmission upgrades are completed.

PG&E Transmission Expansion Plans for Renewable Resources

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

Table 24: PG&E Transmission Expansion Plan Summary

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

In its Plan, PG&E notes that these projects are at "conceptual studying stages", and, as a result, definitive conclusions should not be drawn with respect to project details or timing. However, there is no doubt that PG&E will target certain renewable transmission projects for completion

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

to further its achievement of the state's renewable portfolio standard, which mandates 20% renewable energy sales by 2010 and potentially 33% by 2020.

In addition to these specific projects/focus areas, PG&E is also involved in studying various other projects, such as the development of electric transmission to accommodate the transfer of 4,000 MW of wind generation from the Tehachapi Region. Based on CPUC Decision 04-06-010, the Tehachapi Collaborative Study Group was formed "to develop a comprehensive transmission development plan for the phased expansion of transmission capabilities in the Tehachapi area." Membership in this group includes PG&E, SCE, the CEC, the CPUC, the CAISO, wind energy developers and other stakeholders. Based on its studies, PG&E identified three transmission development alternatives that would accommodate importing 2,000 MW of wind generation from the Tehachapi region to northern California (another 2,000 MW would be available for southern import). A preferred alternative has been identified (new Tesla-Gregg 500 kV line and new Gregg-Midway 500 kV line, which was previously noted) and is still in PG&E's planning/study phases.

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

CCA Access to Transmission and the Transmission Planning Process

As noted above, the Authority would have the same access as PG&E to this transmission once the projects are completed. The Authority would be able to participate in the regional and subregional transmission planning processes as well because these processes are required by FERC to be open and non-discriminatory. The California Independent System Operator has primary responsibility for conducting the transmission planning process for the PG&E area. Furthermore, a recent effort known as the Renewable Energy Transmission Initiative (RETI) has been launched as a statewide initiative to help identify the transmission projects needed to accommodate renewable energy goals, support future energy policy, and facilitate transmission corridor designation and transmission and generation siting and permitting. According to the program website, RETI will be an open and transparent collaborative process in which all interested parties are encouraged to participate. The RETI will assess and prepare detailed transmission plans for the competitive renewable energy zones (CREZs) in California and possibly also in neighboring states that can most cost effectively provide significant electricity to California consumers by the year 2020.

These open regional and subregional transmission planning processes are intended to ensure that all stakeholder needs are represented in transmission planning and to avoid a situation where the needs of the IOUs are placed ahead of others.

Sources of Renewable Energy in the 2012 to 2020 Timeframe

For mid and long term planning purposes, the Authority should anticipate procurement from the following types of large scale renewable resources[17]:

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

Procurement of Renewable Energy

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

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

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

It bears mentioning that the Authority will be in competition for renewable resources with the three investor owned utilities, which together require nearly 12 million MWh annually to meet their RPS requirements by 2010. The Authority, working with third party electric suppliers, will need to be aggressive in pursuing the renewable resources that are available to ensure that PG&E and the other utilities do not lock up the most economic resources for their own portfolio needs during the early years of the Program.[18] Over the longer term, the transmission expansion plans of the utilities will provide additional resource options for the Authority.

Planned Renewable Generation Resources

The resource plan includes the anticipated development by the Authority of a wind resource located within the PG&E service territory.[19] The wind resource is planned to become operational in 2013. Due to strong demand for renewable energy, it is possible that the online date could slip by one to two years. Possible locations include wind resource areas in Solano County, the Altamont wind resource area in Alameda County and potentially the Tehachapi area. The latter location is within the SCE service territory, and would become a feasible location to site generation for the Authority once PG&E expands its import capabilities from that area as discussed above. Resources located in the Pacific Northwest may also be feasible if the Authority can partner with an entity such as SMUD or another California publicly owned utility that has transmission rights from Oregon into California (e.g., the California Oregon Transmission Project) or if PG&E follows through with plans to expand its transmission system northward.

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

Table 25: Community Wind Project Summary[20]

Generation Type	Wind
Location	Greater Bay Area (e.g., Solano County)
Year On Line	2013
Capacity	125 MW
Production	321,930 MWh Per Year
Total Initial Cost	$188 Million
Average Total Cost	$75 to $78 Per MWh (Excluding Incentives)[21]

[18] It should be noted, however, that none of the respondents to the Cities' request for information identified availability of renewable resources as one of the challenges to meeting the Program's stated objective of 50% renewable energy by 2017.
[19] While wind energy has been included in this plan, other renewable technologies could be developed as opportunities arise during the Authority renewable procurement process.
[20] Estimated costs include costs of siting, environmental review and permitting, insurance and construction.
[21] The cost of Power Production shown in the pro-forma contained in Attachment D includes a 1.8 cents per kWh incentive payment under the Renewable Energy Production Incentive for the first ten years of plant operation.

Due to the well documented problem with avian mortality caused by older generation wind turbines, the Authority would only proceed with development of a wind resource if it can be shown to have minimal impact on wildlife. It is generally accepted that modern wind turbines do not cause the same types of wildlife impacts as the 1980's vintage turbines that have high associated avian mortality rates. Knowledge and technological advances in the wind industry, including much taller towers and larger, slower moving turbine blades, have significantly reduced the impacts on wildlife. The Authority's Board of Directors could establish specific criteria for wildlife impacts by which it would authorize investments in wind resources. This is another aspect of the local control that the CCA Program would afford; the local community (working through the Authority) rather than private developers or PG&E, would be able to define the environmental criteria that would govern its power supply.

Energy Efficiency

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 to fund Public Purpose Programs or Public Good Programs (PGC). 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, under CCA, enabling legislation[22] permits CCAs to apply to administer cost-effective energy efficiency programs. All electric utilities in the state include energy efficiency programs in their resource portfolios and annual budgets for California's distribution utilities are approximately $700 million. Energy efficiency programs provide a least cost resource and enhance customer service.

This section addresses the treatment of energy efficiency as a component of an integrated resource plan. As described below there are opportunities for significant cost effective energy efficiency programs within the region, and the Authority would seek to maximize end-use customer energy efficiency by facilitating customer participation in existing utility programs, and forming new programs that displace the Authority's need for procuring electric supply.

Applicable Energy Efficiency Policy

The CPUC and state energy policy, as expressed in the Energy Action Plan and reaffirmed in Decision (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

Unavailability of this incentive payment would increase projected Program rates by approximately $0.002 per kWh for years 2013 through 2022.

[22] AB 117, Chapter 838, Chaptered September 24, 2002, adding Section 381.1 to Public Utilities Code

to meet customers' energy service needs.[23] 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.[24]

Accordingly, the primary indicator of cost effectiveness is the Total Resource Cost (TRC) in keeping with the focus on resource alternatives to supply-side options. The TRC test measures net resource benefits in terms of life-cycle avoided costs of the supply-side resources avoided or deferred. TRC costs encompass the cost of the measures (equipment installed) and the costs incurred by the program administrator. If the net-present-value of avoided supply-side costs, over the estimated useful life of the equipment, is greater than the equipment and program costs, the project is deemed cost-effective (a TRC cost test ratio > 1).

In addition to the TRC test, the Program Administrator Costs (PAC) test is employed comprising what is called the "Dual-Test". The PAC test of cost-effectiveness treats benefits the same as with the TRC test, but costs include only those incurred by the administrator. To support comparisons of all resources in the load serving entity's procurement portfolio, program administrators are required to also provide levelized unit cost estimates at the portfolio, end-use and measure level.[25]

Existing Programs

In consideration of the levels of funding and service provided it is helpful to view potential Authority energy efficiency programs against the current baseline of PG&E's energy efficiency programs.

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

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

[25] Cost-effectiveness indicators referred to above are described in the California Standard Practices Manual (SPM): Economic Analysis of Demand-Side Management Programs. Program administrators and implementers are directed to perform cost-effectiveness analyses consistent with indicators and methodologies included in the SPM (Id.)

Table 26: Pacific Gas & Electric Energy Efficiency Programs 2006 - 2008

Program Type	Pacific Gas & Electric Programs	2006		2007		2008		Total	
Residential Retrofit	Mass Market - Residential	$96,368,062	39.4%	$118,939,725	42.6%	$145,434,713	42.4%	$360,742,499	41.6%
Residential New Construction	Residential New Construction	$9,944,239	4.1%	$11,690,504	4.2%	$14,411,324	4.2%	$36,046,067	4.2%
Nonresidential Retrofit	Mass Market - Nonresidential	$24,092,015		$29,734,931		$36,358,678		$90,185,625	
	Industrial	$38,789,723		$40,178,257		$42,872,399		$121,840,379	
	AG & Food Processing	$13,986,001		$14,861,500		$18,675,630		$47,523,131	
	Commercial (Office Buildings)	$10,510,686		$11,342,972		$15,045,397		$36,899,055	
	Medical	$7,575,132		$7,925,714		$12,918,178		$28,419,024	
	Retail	$5,148,264		$5,667,321		$8,053,199		$18,868,784	
	High Technology	$4,870,934		$5,136,153		$9,330,136		$19,337,223	
	School, Colleges & Universities	$4,510,204		$4,448,700		$9,432,966		$18,391,870	
	Hospitality (Lodging)	$1,581,996		$1,860,632		$2,532,844		$5,975,472	
	total	$111,064,955	45.4%	$121,156,180	43.4%	$155,219,427	45.2%	$387,440,563	44.7%
Nonresidential New Construction	Not Identified	N/A		N/A		N/A		N/A	
Other	Marketing & Outreach	$8,982,794		$8,982,794		$8,982,794		$26,948,382	
	Education & Training	$13,117,200		$13,379,544		$13,897,857		$40,394,601	
	Emerging Technologies	$3,672,000		$3,745,440		$3,842,937		$11,260,377	
	Codes & Standards	$1,504,500		$1,534,590		$1,596,664		$4,635,754	
	total	$27,276,494	11.1%	$27,642,368	9.9%	$28,320,252	8.2%	$83,239,114	9.6%
	Total Energy Efficiency Programs	$244,653,750	100.0%	$279,428,777	100.0%	$343,385,716	100.0%	$867,468,243	100.0%
EM&V		$21,274,235		$24,298,155		$29,859,627		$75,432,017	
Total Energy Efficiency Expenditures		$265,927,985		$303,726,932		$373,245,343		$942,900,260	

Combined CPUC Jurisdictional Energy Utilities EE Funding
CPUC Decision D.05-09-043, ATTACHMENT 4: PROGRAM BUDGETS AND PROJECTED SAVINGS

Energy Efficiency in the Authority

Demand-side resources will form a part of the Authority's resource portfolio, consistent with the treatment of energy-efficiency and demand-side management alternatives within the resource portfolios of California's major investor-owned electric utilities (IOU). An energy efficiency potential forecast has been prepared to serve as a means to estimate the scope and types of energy efficiency programs the Authority might include within its resource portfolio within the following customer segments:

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

Preliminary program planning is prepared based on the conduct of an energy efficiency forecast that employs key assumptions and methodologies adopted by IOUs, tailored to EBPA'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. Details of the energy potential forecast methodology and results are contained in Appendix C.

Energy Efficiency Potential

Conservative estimates indicate energy efficiency potential exists in the Authority's territory to save 28,600 MWh annually achievable through implementing energy efficiency programs funded at approximately $4.1 million. The following table summarizes these findings:

Table 27: Energy Efficiency Potential

EBPA Service Territory

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	897,249,696	482,319,881	163,126,154	12,708,828	1.4%	3,382	$2,224,558
Commercial	1,241,595,231	165,003,537	120,249,752	14,920,685	1.2%	2,545	$1,831,694
Industrial	528,233,896	70,150,040	66,178,871	961,191	0.2%	148	$35,062
Composite	2,667,078,823	717,473,459	349,554,777	28,590,704		6,076	$4,091,315

To achieve energy efficiency program content parity with IOU procurement portfolios, the Authority's resource plan would include energy efficiency resources equal to approximately 22.5 percent of forecast achievable energy efficiency potential within its proposed service territory. This would require the Authority's resource portfolio to include energy efficiency activities resulting in approximately 6,400 MWh energy savings, annually, following a ramp-up period.[26]

Demand Response

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

In its 2007 ruling on local resource adequacy, the CPUC found that dispatchable demand response resources as well as distributed generation resources should be allowed to count for local capacity requirements. The CPUC found that it may not be possible to count dispatchable

[26] Energy Efficiency Resource Standards: Experience and Recommendations, American Council For An Energy-Efficiency Economy, March 2006, page 29-31 – Target Size

demand response resources until 2008. This plan assumes that the Authority's demand response programs would offset its local capacity requirements beginning in 2011.

PG&E offers several demand response programs to its customers, and the Authority intends to recruit those customers that have shown a willingness to participate in utility programs into the Authority's demand response programs.[27] Consistent with the Statewide targets, the goal for this resource plan is to meet 5% of the Program's total capacity requirements through dispatchable demand response programs that qualify to meet local resource adequacy requirements. This goal translates into approximately 25 to 30 MW of peak demand enrolled in the Authority's demand response programs. Achievement of this goal would displace approximately 30% of the Authority's local capacity requirement.

Table 28: Demand Response Goals

East Bay Power Authority
Demand Response Goals
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Capacity Requirement (MW)	264	512	516	520	525	530	538	544	552	560
Demand Response Target	-	26	26	26	26	27	27	27	28	28
Percentage of Local Capacity Requirment	0%	30%	30%	30%	30%	30%	30%	30%	30%	30%

The Authority would adopt a demand response program that enables it to request customer demand reductions during times when capacity is in short supply or spot market energy costs are exceptionally high. The level of customer payments should be pegged to the cost of local capacity that can be avoided as a result of the customer's willingness to curtail usage upon request. This value can range from $50 to $125 per kW-Year. For planning purposes, the customer incentive is assumed to be $75 per kW-year, which is near the backstop price for local capacity resources and above the incentive levels currently offered by PG&E.[28]

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

[27] These programs include the Base Interruptible Program (E-BIP), the Demand Bidding Program (E-DBP), Critical Peak Pricing (E-CPP), Optional Binding Mandatory Curtailment Plan (E-OBMC), the Scheduled Load Reduction Program (E-SLRP), and the Capacity Bidding Program (E-CBP).

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

Distributed Generation

Consistent with the Authority's environmental policies and the state's Energy Action Plan, clean distributed generation is a significant component of the integrated resource plan. The Authority would work with state agencies and PG&E to promote deployment of photovoltaic (PV) systems within the Authority's jurisdiction, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public goods surcharges. PV systems are relatively expensive sources of electricity, even after considering the available buy-downs, tax incentives and benefits of net energy metering. Average production costs are approximately 35 to 40 cents per kWh range as shown below. For reference, the highest priced "Tier 5" rate charged by PG&E is currently 37 cents per kWh.

Table 29: Typical Costs of Residential Photovoltaic Systems

Residential Photovoltaic Costs

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

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

The Authority's CCA customers would contribute funds to the California Solar Initiative through the public goods charge collected by PG&E, and would be eligible for the incentives provided under that program for installation of PV systems. The California Solar Initiative provides $2.2 billion of funding to target installation of 1,940 MW of solar systems within the investor owned utility service areas by 2017. All electric customers of PG&E, SCE, and SDG&E are eligible to apply for incentives. Approximately 44% of program funding is allocated to the PG&E service territory. Assuming solar deployment would be proportionate to funding, the program is intended to yield approximately 775 MW of solar within the PG&E service area. Approximately 27 MW would be deployed within the jurisdictional boundaries of the Authority.

Table 30: Distributed Solar Goals

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	1,969	1,999
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	788	799
East Bay Share of PG&E Load	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
East Bay Solar Deployment (MW)	11	14	16	19	22	24	25	27	28	28

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

Impact of Resource Plan on Greenhouse Gas Emissions

Reductions in greenhouse gas emissions as a result of the Program' resource plan are estimated to range from 325,000 to 580,000 metric tons per year by 2017. The basis for the estimate is an increase from 20% to 50% in the contribution of renewable resources to the resource mix used to serve electric customers in the three Cities. The baseline for comparison is the resource mix that would be used by PG&E in the absence of a CCA versus the resource mix that would be utilized by the CCA Program. This comparison assumes PG&E would meet the 20% RPS target by 2017. The actual impact would be less if PG&E exceeds the target, either voluntarily or by future mandate.

The precise impact on greenhouse gas emissions will depend upon the resources that would be displaced by the CCA's renewable resources. New resources will generally displace the least efficient, highest cost resources in the system as resources are dispatched on the basis of variable operating costs. The baseload nuclear, coal and hydro resources currently in the system resource mix will likely not be displaced because of their low operating costs. The low end of the estimate assumes that new renewables compete with new, efficient natural gas fired resources, while the higher estimate assumes displacement of the less efficient existing fleet of gas-fired resources. The CO2 conversion factors for avoided air emissions used in these estimates were obtained from figures reported by the California Energy Commission (400 metric tons per GWh for new gas-fired resources, and 707 metric tons per GWh for existing resources).[29]

Table 31: Greenhouse Gas Emissions Impact

East Bay Power Authority
Greenhouse Gas Impact
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
East Bay Renewables (MWh)	178,501	503,573	637,198	774,559	915,947	1,061,083	1,211,610	1,364,864	1,385,337	1,406,117
Renewables Per PG&E @ RPS (MWh)	178,501	503,573	509,759	516,373	523,398	530,542	538,493	545,946	554,135	562,447
Program Renewable Impact (MWh)	-	-	127,440	258,186	392,549	530,542	673,117	818,919	831,202	843,670
CO2 Reduction - Low (tonnes per year)	-	-	50,976	103,275	157,020	212,217	269,247	327,567	332,481	337,468
CO2 Reduction - High (tonnes per year)	-	-	90,100	182,538	277,532	375,093	475,894	578,975	587,660	596,475

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

Considering the challenges faced by PG&E in achieving the 20% RPS minimum by 2010 described in its renewable resource plans filed with the CPUC, it is unlikely that PG&E would exceed this level in the foreseeable future. However, some state policy makers, including the Governor, are advocating a 33% renewable portfolio standard by 2020, and a CPUC study found that such a goal could be achieved. The greenhouse gas reduction mandate of Assembly Bill 32 may also add momentum to a 33% renewable portfolio standard, although the compliance rules will not be known for several years. Under the assumption that the statewide standard is increased to 33%, the greenhouse gas benefits of the CCA program would be reduced to a range of 190,000 to 335,000 per year.

It is important to note that although the CCA Program will reduce total CO2 emissions, the average CO2 emissions rate for the CCA Program will initially be higher than PG&E's average emissions rate and may not be substantially better than PG&E's rate in the future. This is due to PG&E's ability to take credit for its large hydro-electric and nuclear resources. This observation may lead one to conclude that the CCA Program's emissions are no cleaner than PG&E's. This is true as far as it goes, but by forming a CCA and acquiring new renewable

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

resources, the CCA Program will reduce PG&E emissions as well. This will make it difficult to communicate the role of the CCA Program in reducing CO2 emissions. The CCA Program could focus its messaging on the appropriate use of sustainable renewable resources as opposed to large hydro and nuclear as a means of addressing climate change. The CCA Program might also consider establishing a goal of using 100% renewable energy, recognizing that a rate premium would be required, to draw a sharper distinction between the value of the Program relative to the status quo.

CHAPTER 4 – Financial Plan

This Chapter examines the monthly cash flows expected during the Implementation Period of the CCA Program and identifies the anticipated financing requirements for the overall CCA Program by the Authority. It includes estimates of Program startup costs, including the necessary staffing and capital outlays which would commence once the CPUC accepts the Implementation Plan submitted by the Authority. It also describes the requirements for working capital and long term financing for the investment in renewable generation, consistent with the resource plan contained in Chapter 3. Finally, this chapter presents an analysis of risk and uncertainties regarding the ability of the Program to achieve its objectives while offering rates that would be competitive with PG&E's.

The cash flow analysis is indicative of Program financials utilizing prices provided by potential electric suppliers during February 2007 in response to the request for information issued by the Cities. Of the three qualified suppliers that provided the requested pricing information, two of the pricing offers were slightly above the price threshold of 8.0 cents per kWh required for Program rates to be at or below PG&E's during the Implementation Period. The prices provided by a third respondent were well above this price threshold. The indicative pricing responses based on market data current as of February 2007 generally indicate that a financially viable Program could be offered if customers accept rates that are somewhat higher than PG&E's or if changes to PG&E rates increase the baseline projection by 3% or more. The electricity markets being as dynamic as they are, however, there can be no certainty that prices will be in the required range at the time the Program is ready to execute a power supply contract. The Cities will be at risk for their Program development costs and staff time incurred up to the time that firm prices are obtained from suppliers. This risk is unavoidable because, before being in a position to execute a power supply contract, the JPA must be established with authorization to proceed with Program implementation if prices meet the required threshold. The estimated costs for development activities up to the time the power supply contract can be executed are approximately $500,000 to $750,000, which could be shared among the Cities. These costs are categorized as Pre-implementation Costs and are described below.

Description of Cash Flow Analysis

This cash flow analysis estimates the level of working capital that would be required until full implementation of the CCA program is achieved. For the purposes of this analysis, it is assumed that the Implementation Period begins in January 2010 and continues through December 2012. In general, the components of the cash flow analysis can be summarized into two distinct categories: (1) Cost of CCA Program Operations, and (2) Revenues from CCA Program Operations. The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with the CCA Program Implementation Period, and specifically account for the transition or "Phase-In" of CCA Customers from PG&E's service territory described in Chapter 3.

Cost of CCA Program Operations

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

- Electricity Procurement
- Ancillary Service Requirements
- Exit Fees (Cost Responsibility Surcharges) to PG&E
- Staffing Requirements
- Contractor Costs
- Infrastructure Requirements
- Billing Costs
- Scheduling Coordination
- Grid Management Charges
- Franchise Fees Surcharge

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

Revenues from CCA Program Operations

The cash flow analysis also provides estimates for revenues generated from CCA operations or from electricity sales to customers.[30] In determining the level of revenues, the cash flow analysis assumes the customer phase-in schedule noted above, and assumes that the Authority's CCA Program establishes rates at a 3% premium to PG&E's generation rate for each customer class. Based on this assumed pricing, Table 32 provides a comparison of the projected distribution utility rate and the Authority's electric rate over the CCA program Implementation Period.

[30] There would be no impact from the Program on revenues derived from the Utility Users' Tax as long as the CCA Program Rates are the same as PG&E's.

Table 32: East Bay Power Authority
Comparison of Electric Rates – Authority Versus PG&E[31]

CATEGORY	2010	2011	2012
Authority's Electric Rate ($/MWh)	$95.83	$91.02	$94.11
IOU Electric Rate ($/MWh)	$93.03	$88.36	$91.37
Variance ($/MWh)	($2.79)	($2.65)	($2.74)
Variance (%)	-3.0%	-3.0%	-3.0%

Cash Flow Analysis Results

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

With the assumptions regarding payment streams, the cash flow analysis itself identifies funding requirements while recognizing the potential lag between payments received and payments made during the Implementation Period. The estimated financing requirements for the Implementation Period (2010 – 2012), including working capital, based on the phase-in of customers as described above is approximately $17 million. Working capital requirements reach this peak shortly after enrollment of the Phase 3 customers.

CCA Program Implementation Feasibility Analysis

In addition to developing a cash flow analysis which estimates the level of working capital required to get the Authority through full CCA implementation, a summary analysis that evaluates the feasibility of the CCA program during the Implementation Period has been prepared. The difference between the cash flow analysis and the CCA feasibility analysis is

[31] Both rates include the Energy Cost Recovery Amount component of the Cost Responsibility Surcharge.

that the feasibility analysis does not include a lag associated with payment streams. In essence, costs and revenues are reflected in the month in which service is provided. All other items, such as costs associated with CCA Program operations and rates charged to customers remain the same.

The results of the feasibility analysis, based on the power supply cost figure discussed above, are shown below in Table 33. Under these assumptions, over the entire Implementation Period the CCA program would accrue a reserve account balance of over $12 million. These projections are based on power supply costs of approximately 8.3 cents per kWh and the Program rates discussed above. Based on current PG&E rate designs, power supply costs would need to be below approximately 8.0 cents per kWh for the three-year startup period to enable the Program to at least match PG&E's rates, while increasing the renewable energy content offered to customers. The RFI responses were slightly above the breakeven level, meaning that slightly higher rates are projected under the CCA Program. Because this difference is small, it is possible that PG&E rate changes during the next few years or changes is the energy markets would allow the Program to offer rates equivalent to PG&E's. Alternatively, rates that are only slightly above PG&E may be acceptable to customers considering the high renewable energy content offered under the Program and the opportunities for lower rates over the longer term.

Table 33: East Bay Power Authority
Summary of CCA Program Implementation
(June 2009 through December 2012)

CATEGORY	2009	2010	2011	2012	TOTAL
I. REVENUES FROM OPERATIONS ($):					
(A) ELECTRICITY SALES:					
RESIDENTIAL	$0	$8,893	$76,278,669	$80,051,567	$156,339,129
GENERAL SERVICE (A-1)	$0	$371,799	$29,657,961	$31,124,904	$61,154,663
SMALL TIME-OF-USE (A-6)	$0	$416,894	$6,702,108	$7,033,608	$14,152,610
ALTERN. RATE FOR MEDIUM USE (A-10)	$0	$32,592,388	$45,592,503	$47,847,600	$126,032,491
500 - 900kW DEMAND (E-19)	$0	$23,129,101	$31,680,560	$33,247,544	$88,057,204
1000 + kW DEMAND (E-20)	$0	$27,597,299	$38,250,056	$40,141,981	$105,989,336
STREET LIGHTING & TRAFFIC CONTROL	$0	$2,949,981	$2,971,936	$3,118,934	$9,040,851
AGRICULTURAL PUMPING	$0	$0	$5,112	$5,365	$10,477
TOTAL REVENUES	$0	$87,066,355	$231,138,904	$242,571,503	$560,776,762
II. COST OF OPERATIONS ($):					
(A) ADMINISTRATIVE & GENERAL (A&G):					
STAFFING	$335,156	$2,104,036	$2,338,987	$2,398,137	$7,176,317
INFRASTRUCTURE	$153,833	$209,500	$184,990	$189,668	$737,992
CONTRACTOR COSTS	$434,833	$1,857,417	$3,108,875	$3,100,235	$8,501,360
IOU FEES (INLCUDING BILLING)	$201,126	$459,445	$2,787,877	$2,475,796	$5,924,243
SUBTOTAL - A&G	$1,124,949	$4,630,398	$8,420,729	$8,163,837	$22,339,912
(B) CCA PROGRAM OPERATIONS:					
ELECTRICITY PROCUREMENT	$0	$71,834,969	$206,977,090	$215,333,790	$494,145,849
EXIT FEES	$0	$2,889,322	$8,075,761	$8,196,898	$19,161,980
FRANCHISE FEES	$0	$663,545	$1,854,632	$1,882,451	$4,400,627
SUBTOTAL - CCA PROGRAM OPERATONS	$0	$75,387,835	$216,907,483	$225,413,139	$517,708,456
(B) OTHER EXPENSES:					
INTEREST	$510,000	$1,020,000	$1,020,000	$1,020,000	$3,570,000
ALLOWANCE FOR UNCOLLECTABLES	$0	$696,531	$1,849,111	$1,940,572	$4,486,214
SUBTOTAL - OTHER EXPENSES	$510,000	$1,716,531	$2,869,111	$2,960,572	$8,056,214
TOTAL COST OF OPERATION	$1,634,949	$81,734,764	$228,197,323	$236,537,547	$548,104,583
CCA PROGRAM SURPLUS / (DEFICIT)	($1,634,949)	$5,331,591	$2,941,581	$6,033,956	$12,672,179

Pre-Implementation Costs

From the date of this plan to the time when the JPA would be in a position to finance its start-up costs, the Cities would need to fund several pre-implementation activities. These include the following:

- Develop and adopt city ordinances
- Form the JPA and conduct meetings
- Implement communications program, conduct customer outreach, and marketing
- Select suppliers and negotiate agreements
- Obtain legal and regulatory support

The total costs of these activities are estimated to range between $500,000 and $750,000. These costs could be shared among the Cities and ultimately repaid from Program rates. However, if the Program does not go forward, these funds would be at risk.

One approach to allocating the pre-implementation costs among the Cities would be to allocate one half of the costs based on each City's relative share of electricity sold and to allocate one half of the costs equally among the Cities as indicated in the following table.[32]

Pre-implementation Costs

City	Low	High
Berkeley	$130,000	$200,000
Emeryville	$105,000	$155,000
Oakland	$265,000	$395,000

In addition, each City may incur internal costs associated with supporting its participation in the Authority. These costs are estimated at approximately $200,000 per City.

Capital Requirements

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

Staffing costs for the initial twelve-month startup period (June 2009 through May 2010) are estimated to be approximately $1.1 million. Actual costs may vary depending on the ability of the Authority to recruit qualified staff to fill the roles illustrated above. Contractor costs for the same time period are estimated to be approximately $1.3 million. These costs include: advertising/communications, consulting, legal, and data management. Again, actual costs will vary; however, this is a reasonable estimate for the anticipated contractor costs.

Program initiation costs include the infrastructure that the Authority will require (office space, utilities, and computers) as well as the distribution utility fees for initiating the CCA Program. Infrastructure costs are estimated to be approximately $250,000 and the distribution utility fees are estimated to be approximately $600,000.

Therefore, the total staffing, contractor and Program initiation costs are expected to be approximately $3.3 million. These are costs that ultimately will be collected through CCA Program rates; however, most of these costs will be incurred prior to the Authority selling its

[32] This allocation method has been used to by the Cities to fund the Cities' share of program development expenses to date.

first kWh of electricity. In addition, it is anticipated that additional working capital will be required to purchase electricity for Program customers prior to revenue being collected from those customers. During the start-up period, the total financing requirement is estimated to be approximately $17 million, of which approximately $10 million is to support start-up through Phase 2. The actual amount of startup capital will be primarily dependent upon power purchase requirements. The Authority's plans for financing these capital requirements are discussed later in this chapter.

Startup Activities and Costs

The initial startup funding estimate of $3.3 million is budgeted to fund the following activities and costs:

- Define and execute communications plan
    - Media Campaign, Community Outreach and Public Education
    - Informational materials and customer notices
    - Customer call center
- Hire Program Manager, Sales and Marketing representatives, and Finance staff
- Negotiate supplier/vendor contracts
    - Electric supplier
    - Data management provider
- Pay utility service initiation, notification and switching fees
- Perform customer notification, opt-out and transfers
- Conduct load forecasting
- Finalize rates
- Legal and regulatory support
- Financial reporting
- General consulting costs

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

Startup Cost Summary

Monthly costs associated with Program startup and phasing of customer enrollments are shown below for Program staff, associated infrastructure, contractor costs and fees payable to the distribution utilities for CCA implementation and transactions costs. The estimated startup costs include capital expenditures and one-time expenses as well as ongoing expenses that will be accrued before significant revenues from Program operations commence. These costs have been characterized as startup costs for purposes of the financing plan and would be financed by the Authority.

Table 34: Summary of Startup Costs

Start-up Costs		Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1	Phase 1 Operations	Notification and Enrollment Period		Cutover 2
Staffing	Startup Period	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
FTEs		2.5	2.5	2.5	2.5	2.5	6	11	12	16.5	18.5	18.5	18.5
Cost	$ 1,154,089	$ 31,823	$ 31,823	$ 31,823	$ 31,823	$ 31,823	$ 68,724	$ 107,318	$ 116,120	$ 162,500	$ 180,104	$ 180,104	$ 180,104
Infrastructure													
Cost	$ 252,375	$ 7,500	$ -	$ -	$ 75,208	$ 15,208	$ 25,708	$ 30,208	$ 18,208	$ 28,708	$ 21,208	$ 15,208	$ 15,208
Contractor Costs													
Advertising/Comm.	$ 180,000	$ -	$ -	$ -	$ -	$ -	$ 20,000	$ 20,000	$ 10,000	$ 20,000	$ 50,000	$ 50,000	$ 10,000
Consulting	$ 425,000	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417
Demand Side Programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Legal	$ 196,667	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667	$ 16,667
Data Management	$ 512,146	$ -	$ -	$ -	$ -	$ -	$ 16,792	$ 16,792	$ 25,188	$ 25,188	$ 142,729	$ 142,729	$ 142,729
Subtotal Contractor Costs	$ 1,313,813	$ 51,417	$ 51,417	$ 51,417	$ 51,417	$ 51,417	$ 88,875	$ 88,875	$ 87,271	$ 97,271	$ 244,813	$ 244,813	$ 204,813
IOU Fees (Including Billing)													
Cost	$ 616,640	$ -	$ -	$ -	$ 98,390	$ 98,390	$ 2,213	$ 2,132	$ 9,182	$ 5,894	$ 143,390	$ 127,153	$ 129,896
Grand Total	$ 3,336,916	$ 90,740	$ 83,240	$ 83,240	$ 256,838	$ 196,838	$ 185,521	$ 228,533	$ 230,781	$ 294,373	$ 589,515	$ 567,278	$ 530,021

Estimated Staffing Costs

The following table provides the estimated staffing budgets for the startup period, reflecting the staffing plan described in Chapter 2. Staffing budgets include direct salaries and benefits loading.

Table 35: Staffing Costs

Staffing Costs ($/Month)	Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1		Notification and Enrollment Period		Cutover 2
Staff	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
Management												
Manager	$ 16,250	$ 16,250	$ 16,250	$ 16,250	$ 16,250	$ 16,250	$ 16,250	$ 16,250	$ 16,250	$ 16,250	$ 16,250	$ 16,250
Contract Analyst						$ 17,604	$ 17,604	$ 17,604	$ 17,604	$ 17,604	$ 17,604	$ 17,604
Administrative Assistant	$ 3,385	$ 3,385	$ 3,385	$ 3,385	$ 3,385	$ 3,385	$ 3,385	$ 3,385	$ 3,385	$ 3,385	$ 3,385	$ 3,385
Finance and Rates												
Manager	$ -	$ -	$ -	$ -	$ -	$ 14,896	$ 14,896	$ 14,896	$ 14,896	$ 14,896	$ 14,896	$ 14,896
Rates Analyst	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,802	$ 8,802	$ 8,802
Accounting/Billing Analyst									$ 8,802	$ 8,802	$ 8,802	$ 8,802
Administrative Assistant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales And Marketing												
Manager	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188
Account Representatives						$ -	$ -	$ -	$ 26,406	$ 35,208	$ 35,208	$ 35,208
Communications Specialist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,802	$ 8,802	$ 8,802	$ 8,802	$ 8,802
Administrative Assistant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,771	$ 6,771	$ 6,771	$ 6,771
Regulatory												
Regulatory Manager	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188	$ 12,188
Regulatory Analyst	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,802	$ 8,802	$ 8,802	$ 8,802	$ 8,802	$ 8,802
Information Technology												
IT Specialist	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,604	$ 17,604	$ 17,604	$ 17,604	$ 17,604	$ 17,604
Human Resources												
HR Specialist	$ -	$ -	$ -	$ -	$ -	$ 4,401	$ 4,401	$ 4,401	$ 8,802	$ 8,802	$ 8,802	$ 8,802
Subtotal Staffing	$ 31,823	$ 31,823	$ 31,823	$ 31,823	$ 31,823	$ 68,724	$ 107,318	$ 116,120	$ 162,500	$ 180,104	$ 180,104	$ 180,104

Estimated Infrastructure Costs

Infrastructure or overhead needed to support the organization includes 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. The monthly estimated infrastructure costs are shown below.

Table 36: Infrastructure Costs

Infrastructure Costs ($/Month)	Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1		Notification and Enrollment Period		Cutover 2
	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
Computers	$ 7,500	$ -	$ -	$ -	$ -	$ 10,500	$ 15,000	$ 3,000	$ 13,500	$ 6,000	$ -	$ -
Furnishings	$ -	$ -	$ -	$ 60,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Office Space	$ -	$ -	$ -	$ 13,125	$ 13,125	$ 13,125	$ 13,125	$ 13,125	$ 13,125	$ 13,125	$ 13,125	$ 13,125
Utilities	$ -	$ -	$ -	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083
Subtotal Infrastructure	$ 7,500	$ -	$ -	$ 75,208	$ 15,208	$ 25,708	$ 30,208	$ 18,208	$ 28,708	$ 21,208	$ 15,208	$ 15,208
Total Costs	$ 39,323	$ 31,823	$ 31,823	$ 107,031	$ 47,031	$ 94,432	$ 137,526	$ 134,328	$ 191,208	$ 201,313	$ 195,313	$ 195,313

Utility Implementation and Transaction Charges

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

Table 37: Utility Fees

Utility Transaction Fees ($/Month)	Pre-Startup					Enrollment 1 - Pilot Phase		Cutover 1	Phase 1 Opera	Notification and Enrollment Period		Cutover 2
Utility Fees	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
Opt-Out Notifications												
Per Account	$ -	$ -	$ -	$ -	$ -	$ 705	$ 705	$ 705	$ 705	$ 115,524	$ 115,524	$ 1,113
Per Event	$ -	$ -	$ -	$ -	$ -	$ 1,400	$ 1,400	$ 1,400	$ 1,400	$ 1,400	$ 1,400	$ 1,400
Post enrollment notification	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 784	$ -	$ -	$ -	$ 1,236
Service Initiation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Hour	$ -	$ -	$ -	$ 96,000	$ 96,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer List	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Event	$ -	$ -	$ -	$ 2,390	$ 2,390	$ -	$ -	$ -	$ 2,390	$ -	$ -	$ -
Mass enrollment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 784	$ -	$ -	$ -	$ 115,524
Per Event	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,120	$ -	$ -	$ -	$ 4,120
Opt-Out Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Opt Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,381	$ 4,428	$ 16
Customer Contact Fee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Per Minute	$ -	$ -	$ -	$ -	$ -	$ 108	$ 27	$ 18	$ 27	$ 17,714	$ 4,428	$ 2,952
Billing Fee												
Per Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 3,535
Subtotal	$ -	$ -	$ -	$ 98,390	$ 98,390	$ 2,213	$ 2,132	$ 9,182	$ 5,894	$ 143,390	$ 127,153	$ 129,896

Estimates of Third Party Contractor Costs

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

Table 38: Contractor Costs

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

Financing Plan

The initial start-up funding would be provided by the Authority via a short-term financing, likely a letter of credit or issuance of commercial paper. The appropriate financial instrument should be determined in consultation with the City's bankers or the banker selected by the Authority following its formation. The Authority would recover the principal and interest costs associated with the start-up funding via retail rates. It is anticipated that the start-up costs would be fully recovered within the first five years of the Program operations through retail rates.

Working Capital

For purposes of determining working capital requirements related to power purchases, it is assumed that operating revenues from sales of electricity will be remitted to the Authority on approximately day 47 of Program operations, based on PG&E's standard meter reading cycle of 30 days and PG&E's payment/collections cycle of 17 days. Either the electric supplier or the Authority will be responsible for providing the working capital needed to support electricity procurement, subject to the outcome of negotiations with the selected electric supplier.[33] If it is the electricity provider, this cost will be reflected in its price for providing full requirements electric service to the Program. Regardless, of this being provided by the third party supplier or the Authority, the Authority will be obligated to meet working capital requirements related to Program management, which will be included in the short term financing associated with start-up funding.

Pro Forma

Ongoing operating expenses will be recovered from revenues accruing from sales of electricity to Program customers and, where applicable, sales of excess power to other entities. Pro forma projections for the initial four years of Program operations are shown in this chapter. Pro forma projections for the longer term, including debt service for the Authority's renewable generation investments, are included in Appendix D.

Authority Financings

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

1. CCA Program start-up and working capital estimated at $17 million
2. Renewable generation project financing – $190 million

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

CCA Program Start-up and Working Capital

As previously discussed, the anticipated start-up and working capital requirements for the CCA Program through complete implementation are $17 million. Depending upon the arrangements made between the Authority and the third party supplier the amount could potentially be as low as $3 million because $14 million is for working capital related to power purchases that may ultimately be carried by the Program's electric supplier rather than the Authority. Once the CCA Program is up and running, these costs would be recovered from the retail customers through retail rates. Actual recovery of these costs will be dependent on third-party electricity purchase prices and decisions regarding rates, and negotiations between the electric supplier and the Authority's Board of Directors.

It is assumed that this financing will be via a letter of credit (LOC) or commercial paper, which would allow the Authority to draw cash as required and that the financing program could be sized (increased/decreased) should it be needed in the future. This financing would need to commence in mid 2009. The annual interest rate for this financing is expected to be approximately 6%.[34] Although it is possible to implement a working line of credit or commercial paper program for the startup costs, the risk to investors would most likely require some form of secondary security interest in order to keep the interest rate costs down. This would most likely be in the form of a general fund pledge or through the deposit of reserve funds from the participating cities.

Renewable Resource Project Financing

This is the large project financing for the renewable resource (likely wind), currently estimated to be in the $190 million range. This financing would occur once a specific project is completely sited and the CCA Program is up and running. The anticipated date for financial close for the renewable resource project is fall 2010. This financing would take out any short-term financing for the renewable resource project development costs, and will be in the range of a 20- to 30-year term.

The security for these bonds would be a hybrid of the revenue from sales to the retail customers of the Authority, including an Exit Fee (discussed in greater detail in Chapter 5) and the renewable resource project itself. The debt would not be an obligation of the Cities.

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

[34] The London Interbank Offer Rate (LIBOR) plus 50 basis points was used to estimate the Authority's interest costs for short term financing.

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

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

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

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

Table 39: Anticipated Financings

Proposed Financing	Estimated Amount	Estimated Term	Estimated Issuance
1. Pre-Implementation	$500 - $750 thousand	1 to 2 years	Early 2009
2. Start-Up and Working Capital	$17 million	No longer than 7 years	Mid 2009
3. Renewable Resource Project Financing	$185+ million	20-30 years	Late 2010

Sensitivities and Uncertainties

The primary focus of this section is to address the uncertainties and risks that could jeopardize the ability of the Program to offer competitive rates and services to its customers or to meet the policy objective of increasing renewable energy. Any financial risks to the Cities themselves should be limited to the rate impact on the electric accounts of City facilities that would enroll in the Program; however, other potential risks to the Cities themselves are being addressed by outside legal counsel retained by the Cities. Specifically, the Cities have retained legal counsel to ascertain whether implementation of the CCA program through the JPA structure, as generally described in Chapter 2, would preclude individual city liability for Program risks and for actions by the JPA. Legal counsel will be required to finalize the formal governance and program agreements and must make the ultimate determination of whether there would be any residual risk taken on by the Cities through their participation in the Program. Execution of the financing plan will require review and input by legal counsel and potentially investment bankers selected by the Cities to confirm the ability to obtain financing for the proposed Program.

The following discussion provides an overview of the risks and uncertainties inherent in implementing the proposed CCA program. A quantitative risk analysis was performed using the indicative supply costs that were obtained from potential third party electric suppliers. The results of this risk assessment are summarized below.

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

- Participation in the Authority by each City.
- The CPUC's actions, if any, on the Implementation Plan submitted by the Authority.
- Initial costs through 2012 or longer for electric supply and customer account services.

It is presumed that the Cities would not authorize the Program to begin unless the costs offered by electric providers to the Authority are low enough to enable the Program to offer rates to customers at or below the levels charged by PG&E or at a small enough premium that the value of a higher renewable energy content outweighs the costs. Timing of the initial supply contracts will be critical because the wholesale market can move up or down by five percent on any given day, which is enough of a swing to impact the ability to offer competitive rates through the Program. For instance, a 5% increase in market prices would increase the Authority's annual cost by nearly $10 million, enough to turn a projected surplus for 2011 into a deficit. The outcome of these unknowns will be factored into the final evaluation to be made prior to the time the Authority would submit its registration materials to the CPUC. Financing for the Program Startup costs, excluding the $500,000 to $750,000 Pre-Implementation Costs discussed above, would not occur until a decision is made to proceed with Program implementation. These factors are therefore not Program risks per se, but are uncertainties that may adversely impact the ultimate feasibility – or more likely the timing - of going forward with the Program.

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

- The level of PG&E rates in general and for customers served by the CCA program in particular.
- The Cost Responsibility Surcharge and rates for utility services provided to the CCA.
- Future wholesale electricity and fuel prices.
- The precise costs and timing of future resource investments by the Authority.
- Customer opt-outs and turnover.
- The effectiveness of energy efficiency, distributed generation and demand response as means of reducing energy purchases.
- The need for an ongoing marketing program and potential legal fees due to uncertainty in whether the Program will be tested leally or in the market by a competitor or other third party.

Once the Authority locks in the price of its initial supply contract, the primary risk is that market prices subsequently decline and PG&E increases the CRS in future years. The Authority's costs and rates would be largely predictable, but customer rate impacts can only be known with certainty one year in advance because the CRS is determined one year at a time. The most significant market-related risk to the Program's viability would be a period of sustained low electricity prices beginning after the Authority makes long term power supply commitments to renewable resources or other fixed priced electric supplies. The Authority's power supply costs would be relatively stable, but reductions in the market prices of wholesale electricity would tend to increase the CRS charged by PG&E to Program customers. Such declines would also tend to reduce PG&E's rates to some extent. If prices for conventional electricity were to drop for a sustained period of time, the Program's rates could be consistently higher than those offered by PG&E. Customers would bear the risk of being obligated to pay the Authority's rates or pay the Exit Fee to leave the Program. The Authority's strong commitment to renewable energy resources could be costly to participating customers if fossil fuel prices were to steeply decline in the future. This risk is captured in the Monte Carlo simulation analysis that examines the rate impact of shifts in fossil fuel prices, rather than year-to-year price volatility.

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

The other primary uncertainty is the future level of PG&E's generation rates that would otherwise be paid by Program customers. Small differences in the escalation rate of PG&E"s generation rates would have significant impacts on the ability of the CCA Program to provide ratepayer benefits. PG&E rates are impacted by market factors such as power supply costs but are also significantly impacted by regulatory policies, which make the task of accurately forecasting PG&E's rates extremely difficult. PG&E's rates were forecast by modeling the cost of its supply resources using publicly available data for resources where such data are available and assumptions that its power purchases going forward for conventional and renewable supply would be made at the same market prices the CCA Program would face. The rate forecast reflects a post CCA formation scenario where PG&E's sales are reduced by the load that would be served by the CCA Program. The forecast underlying this business plan projects an average increase of 2.3% per year in PG&E's generation rates over the planning horizon, which is relatively low by historical standards. As shown in Figure 10 the average annual increase in PG&E's electric rates has been 4.1% since 1980 and 5.2% since 2000. However, PG&E adjusts its rates at least annually, and actual PG&E rates will only be known with the benefit of hindsight.

The bottom line is that rate comparisons beyond one year are inherently uncertain. Faced with uncertainty, City decision makers need to consider the range and likelihood of the potential outcomes if the decision to offer a CCA program is made. Sensitivities for the primary uncertainties have been prepared using a probabilistic simulation technique known as Monte Carlo Analysis. The Monte Carlo analysis involves defining probability distributions of various uncertain variables and then simulating the potential outcomes of the forecast variable (rate impacts) based on repeatedly varying the input variables in accordance with their underlying probability distributions. The result is a probability distribution of the forecast variable from which ranges of potential outcomes and their likelihood of occurrence can be assessed. The sensitivity analysis shows the impact in the relative rates of the CCA based on temporary and sustained shifts in these variables.

Quantitative Risk Assessment

NCI used a Monte Carlo simulation technique to quantify the probabilities that Program rates would be above or below the rates charged by PG&E during the forecast period of 2010 through 2025. The forecast variable selected for analysis is the average percentage difference in Program total costs versus costs under projected PG&E rates. This variable represents the expected impact on customer bills, assuming Program rates were set to recover Program costs, with positive numbers indicating bill savings and negative numbers indicating bill increases.

For purposes of this analysis, the assumption was made that the CCA would serve 90% of bundled service customers starting on January 1, 2010, and it would utilize a fixed priced, full requirements contract to cover its load requirements through 2015. The planned community wind resource is assumed to become available beginning in 2013 to cover approximately 10% of the Program's annual retail sales, consistent with the resource plan presented in Chapter 3. The remaining load requirements would be covered by contract purchases at market rates.

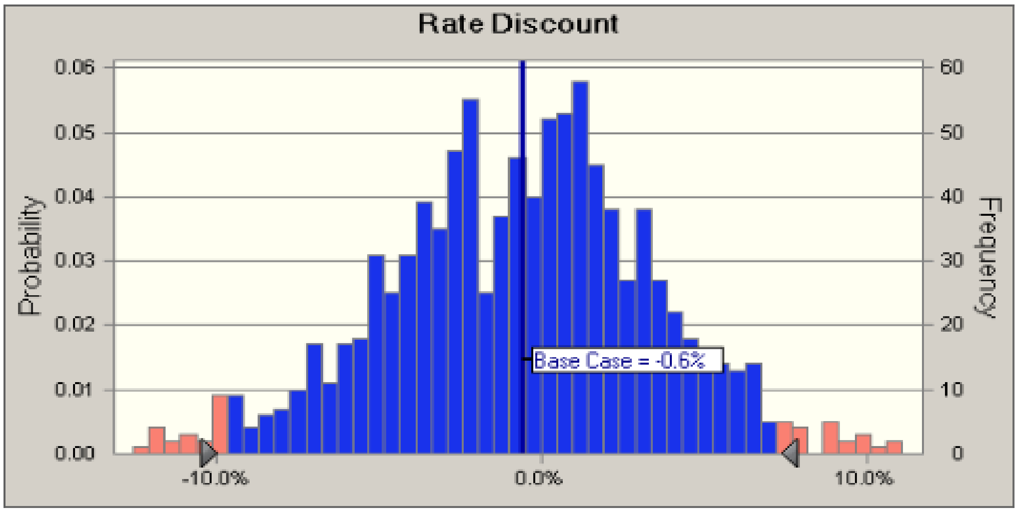
The findings of NCI's analysis are summarized as follows:

- In the base case, CCA generation rates are projected to be slightly below PG&E's (0.1%) on average from 2010 through 2026.

- The Monte Carlo analysis shows that at the 95% certainty level, CCA rates are likely to be between 7% lower and 10% higher than PG&E generation rates, on average during this time period. For reference, a 5% rate difference would be approximately $1.10 per month for the typical residential customer in the Program. The expected ranges and probability distribution of this rate impact are shown in the figure below.

Figure 7: Program Costs Relative to PG&E

Summary:
Certainty level is 95.0%
Certainty range is from -9.9% to 7.2%
Entire range is from -13.9% to 11.6%
Base case is -0.6%
After 1,000 trials, the std. error of the mean is 0.1%



- The input variables having the greatest impact on CCA rates relative to PG&E's rates are as follows:
    - Assumed transmission congestion charges or other transmission (CAISO) charges
    - Renewable energy prices
    - Natural gas and wholesale electricity prices

- Customer opt-out percentages, within expected reasonable ranges, do not have a significant impact on the CCA's rates or financial viability. Greater opt-outs among residential customers would have a slight positive impact on CCA rates (greater possible rate reductions), and greater opt-outs among commercial and industrial customers would have a slight negative impact on CCA rates.

Probability distributions for the following 11 input variables were included in the analysis. These particular inputs were selected based on their potential for impacting the forecast.

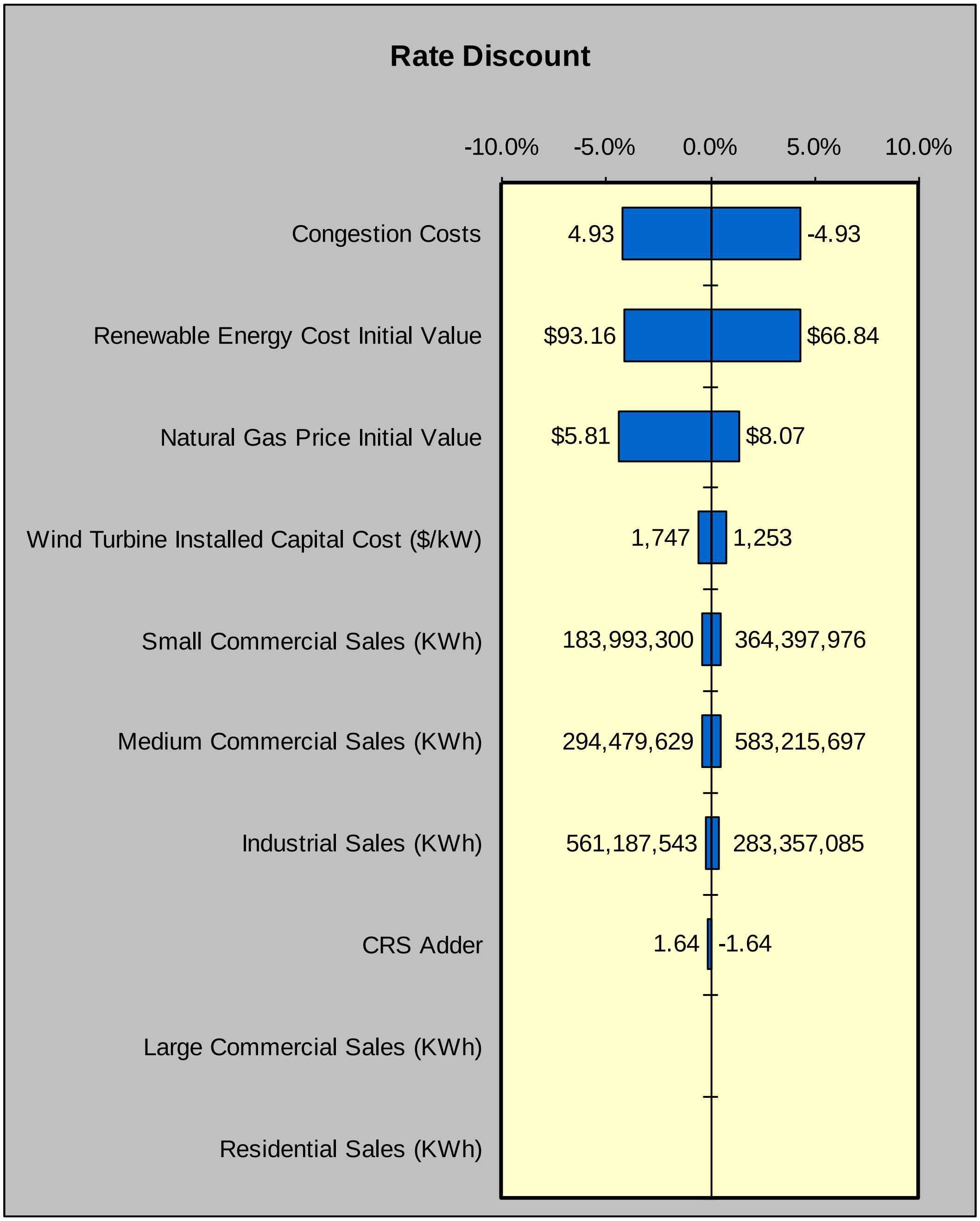
Table 40: Risk Analysis Input Variables

INPUT ASSUMPTION	ASSUMED RANGE	GENERAL IMPACT
Renewable energy prices	+/- 30%	Impacts CCA and PG&E rates
Natural gas prices	+/- 30%	Impacts CCA and PG&E rates through impact on electricity prices and the cost responsibility surcharge
Residential sales (kWh)	+/- 60%	Impact of opt-outs on CCA rates
Small commercial sales (kWh)	+/- 60%	Impact of opt-outs on CCA rates
Medium commercial sales (kWh)	+/- 60%	Impact of opt-outs on CCA rates
Medium industrial sales (kWh)	+/- 60%	Impact of opt-outs on CCA rates
Large industrial sales (kWh)	+/- 60%	Impact of opt-outs on CCA rates
Street and area lighting sales (kWh)	+/- 60%	Impact of opt-outs on CCA rates
Capacity cost – wind generation ($/MW)	+/- 30%	Impacts CCA rates
Transmission congestion costs ($/MWh)	+/- $5 Per MWh	Impacts CCA rates
PG&E hydro-electric production (MWh per year)	+/- 60%	Impacts PG&E system average rates

The probability distributions defined for each of the input assumptions are shown in Appendix E. Except for natural gas prices, each variable was specified as being normally distributed with a mean equal to the base case value and a standard deviation representative of its expected volatility. A lognormal distribution was specified for natural gas prices, consistent with the view that the future price of natural gas is more likely to be above the mean forecast than below.

The relative impact on the forecast (average rate impact or discount) of each input variable can be seen in the following "tornado" chart. The chart shows how each input assumption changes the projected bill savings. The input assumptions with the most significant impacts are shown at the top of the chart. The greatest impact is made by variations in assumed transmission costs, renewable energy prices, and natural gas and wholesale electricity prices.

Figure 8: Variables With Greatest Impact On Relative Rates



	Rate Discount			Input		
Variable	*Minimum*	*Maximum*	*Range*	*Minimum*	*Maximum*	*Base Case*
Congestion Costs	-4.2%	4.3%	8.5%	4.93	-4.93	0
Renewable Energy Cost Initial Value	-4.2%	4.3%	8.5%	$93.16	$66.84	$80.00
Natural Gas Price Initial Value	-4.4%	1.3%	5.7%	$5.81	$8.07	$6.85
Wind Turbine Installed Capital Cost ($/kW)	-0.6%	0.8%	1.4%	1,747	1,253	1,500
Small Commercial Sales (KWh)	-0.4%	0.5%	1.0%	183,993,300	364,397,976	274,195,638
Medium Commercial Sales (KWh)	-0.4%	0.5%	0.9%	294,479,629	583,215,697	438,847,663
Industrial Sales (KWh)	-0.2%	0.4%	0.6%	561,187,543	283,357,085	422,272,314
CRS Adder ($/MWh)	-0.1%	0.1%	0.2%	1.64	-1.64	0
Large Commercial Sales (KWh)	0.1%	0.1%	0.0%	222,072,596	439,813,866	330,943,231
Residential Sales (KWh)	0.1%	0.1%	0.0%	532,151,708	587,372,630	793,037,991

Higher than expected transmission congestion costs would directly increase the Program's costs and therefore its rates. For purposes of this analysis, it is presumed that PG&E's exposure to local congestion costs would be spread to customers throughout its service area, and therefore the impact on PG&E's rates would be minimal. This variable can also stand as a proxy for other, unanticipated costs that would disproportionately impact the CCA Program relative to PG&E.

Increases in renewable energy prices would negatively impact the CCA, because the CCA would be ramping up its renewable portfolio during this time and would be subject to the increased costs. PG&E's renewable energy costs are less impacted because it would be purchasing proportionately less at the higher market prices due to the existing renewable resources in its resource mix.

Increases in natural gas prices would have positive rate impacts because the CCA would have locked in its supply costs through fixed price contracts for the initial period of operations (seven years in this analysis). After this initial term, only one half of the CCA Program's portfolio would be dependent upon fossil fuel prices due to the significant use of renewable resources. PG&E rates will tend to increase as natural gas prices increase because a portion of PG&E's supply portfolio is tied to natural gas prices; e.g., pricing for certain contracts executed by the Department of Water Resources and contracts with some "qualifying facilities" are tied to the price of natural gas. Decreases in natural gas costs would have a significant negative impact on customer's rates because the CRS charges by PG&E would increase.

Interestingly, customer opt-outs, as represented by the customer class annual sales input variables, do not have a significant impact on Program rates within the ranges examined. Residential opt-outs actually allow for greater overall cost savings for CCA customers, while opt-outs by commercial and industrial customers would tend to slightly reduce overall cost savings. This result is consistent with the finding that PG&E's commercial and industrial rates include higher margins than do its residential rates; however, customer opt-out rates within reasonable ranges do not appear to pose significant risk issues.

Other Risks and Uncertainties - Renewables

There is a risk that the CCA may have less impact on increasing renewable energy than projected. On the one hand, PG&E could exceed the RPS, making the difference between a CCA environment and the status quo less significant. On the other hand, the CCA may not be able to secure a 50% renewable content due to cost or availability.

<u>AB 32</u>

AB 32 imposes a statewide requirement to reduce greenhouse gas emissions by 25% by 2020. The rules governing particular industries have yet to be determined, and it is not possible at this time to predict AB 32's impact on PG&E or the CCA program. This plan implicitly assumes a neutral impact on the relative rates of the CCA Program rates and PG&E rates.

One possibility is that AB 32 compliance will push the State toward adoption of the 33% RPS as a mandate on PG&E. This would reduce the overall GHG benefit attributable to the CCA Program. It is also possible that AB 32 will further drive up demand for renewable energy resources and make early renewable energy investments by the Authority that much more attractive. PG&E rates may increase more than projected, and the Authority may be able to financially benefit (offer lower rates) by trading emissions reductions achieved through the CCA. On the other hand, AB 32 may motivate PG&E to increase its renewable energy procurement, and the increased demand for renewable resources could reduce supplies available to the Authority or leave only the least economic resources available. PG&E's rates would be expected to increase as well. A subsequent analysis should be performed once the implementing regulations have been established.

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

Other Risks and Uncertainties – Renewable Procurement Risk

While during the early years of the Program, it is anticipated that a third party electric supplier would be responsible for meeting the Program's renewable energy standard, the Plan anticipates investment in specific renewable resources as soon as practicable. Risks associated with electric resource investments include:

- Price risk – cost increases of the project

- Technical risk – obsolescence of technology
- Construction risk – delays, and quality
- Operating risk – efficient operations, maintenance and repairs
- Asset risk – destruction of asset

Many of these risks are mitigated by contractual terms standard in the industry (e.g., a engineering, procurement and construction contract), insurance, and by partnering with other experienced public power developers such as NCPA or SCPPA.

Other Risks and Uncertainties - Advanced Metering

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

Other Risks and Uncertainties – Management Risks

In addition, there are general risks associated with management of an organization of this type. It is assumed that the CCA will be managed in a fiscally responsible manner. Howerver, incompetent management could result in serious risk for ratepayers and investors. This could result from a political problem (e.g. dysfunctional board of directors) or from internal organizational failures.

Some of these risks include failure to achieve procurement requirements, including penalties for failure to achieve the minimum RPS, failure to meet minimum local generation goals, or failure to meet resource adequacy requirements. Other liabilities exist if the CCA does not properly hedge its risks, fails to ensure that its contractors have the capability or performance bonds to support their contracts or fails to properly manage the operations of the Program.

Other Risks and Uncertainties – Legal Challenges

There is a risk that the Program could be subjected to legal challenge on environmental or other legal grounds and delayed due to activities not within management's control.

Other Risks and Uncertainties – Rate Stability

If the Program owns generating plant for a small portion of its energy requirements (e.g., the initial 20% investment), its rates could be less stable than PG&E, which owns approximately 40% of the generating plant used to serve its customers. However, long-term contracts can also be used to stabilize rates for the CCA. Even so, market price fluctuations could affect CCA ratepayers through escalator clauses in supply contracts (if applicable) and as expiring contracts are rebid.

<u>Allocation of Risk</u>

CCA represents a community ownership model for providing electric service, and Program customers would obtain the benefits as well as some of the risks of the Program's investment in generation resources. The financial benefits take the form of low, stable rates.[35] The risks take the form of a commitment to pay the Authority's rates, which includes coverage for debt service obligations related to resource investments or a commitment to pay the Authority's Exit Fee if the customer wishes to discontinue its participation in the Program. Theoretically, PG&E shareholders would otherwise bear a portion of the risks that would be borne by CCA customers. PG&E shareholders earn a regulated rate of return on equity of approximately 11%, which is intended to compensate shareholders for the risk of investing in PG&E's business operations. An argument can be made that the lower rates that can be offered by the CCA stem from a transfer of risk from PG&E shareholders to CCA customers. Such an argument begs the question: what risks do PG&E shareholders bear with respect to providing generation services?

The evidence suggests that PG&E ratepayers bear the majority of risks related to PG&E electric procurement activities. Pursuant to state law enacted during the 2000-2001 energy crisis, PG&E's energy procurement and generation investment plans are now pre-approved by the CPUC and are not subject to after the fact reasonableness review. [36] Regulatory "balancing account" mechanisms protect shareholders from risks related to power costs and electricity sales by adjusting customer rates to make up for past shortfalls or return over-collections. Shareholders are further protected from financial loss if supply commitments become uneconomic by the Cost Responsibility Surcharge mechanism that is imposed on customers electing to take service from an alternative electric provider. The only risks that appear to be

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[35] CCA rates can be stabilized by investment in renewable generation and by long term power purchase contracts containing fixed or mostly fixed prices.

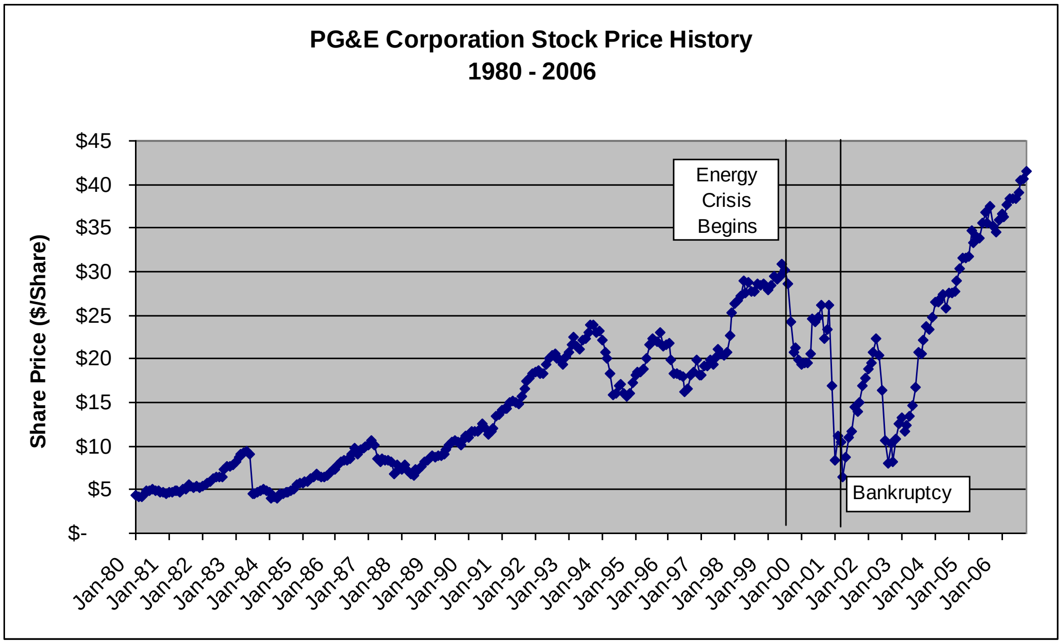
[36] Public Utilities Code Section 455.5.

retained by shareholders would be those costs resulting from failure to adhere to an approved procurement plan, failure to administer contracts in accordance with their terms, or potentially from cost over-runs that exceed authorized levels.

Recent history in the period before and after the PG&E bankruptcy provides a revealing test case for examining the allocation of risk between PG&E shareholders and its ratepayers. As shown below, during the pre-bankruptcy period of 1999, PG&E stock hit an all time high of $32.80 per share during the month of April. The stock hit a low of $6.50 following the Corporation's bankruptcy announcement in April 2001. Today, the stock has recovered all of its losses and has reached new all time highs of over $40.00 in October 2006.[37] Despite bankruptcy of the corporation, a PG&E shareholder that had purchased stock at the high point prior to the energy crisis would have made a 43% return on the investment by the end of 2006.

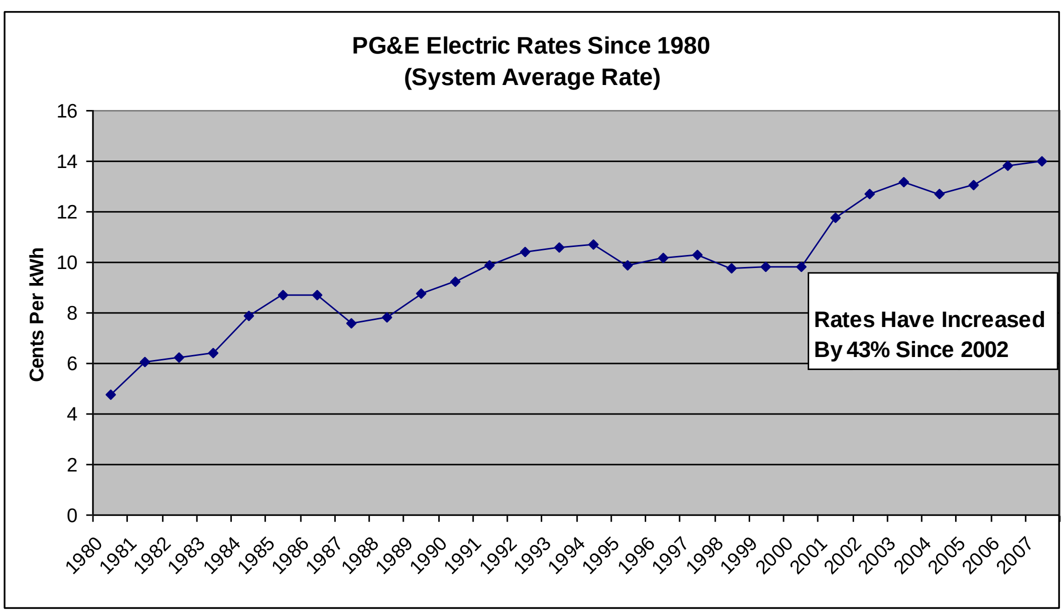
[37] PG&E's stock price has continued to increase and is now over $43 per share as of January 17, 2008.

Figure 9: PG&E Stock Prices



During the same period, customer rates have risen by 43% as shown the following chart.

Figure 10: PG&E Rate History



There is little doubt that PG&E's customers ultimately bore the brunt of the energy crisis costs, and there is no evidence that would suggest PG&E shareholders have assumed a greater portion of risks since that time. If anything, shareholder risk has been lessened due to regulatory and legislative actions taken in response to the energy crisis aimed at returning the utilities to financial solvency. It does not appear that PG&E shareholders are currently absorbing significant levels of risk that would be borne by customers joining a CCA program; i.e., most risks are borne by ratepayers under either the utility or CCA service model.

CHAPTER 5 - Ratesetting and Program Terms and Conditions

Introduction

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

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

Rate Policies

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

The primary objective of the ratesetting plan is to set rates that achieve the following:

- Rate competitiveness
- Rate stability
- Equity among customers (including low income customers)
- Customer understanding
- Revenue sufficiency

Each of these objectives is described below.

Rate Competitiveness

The goal is to offer competitive rates for the electric services the Authority would provide to participating customers. The goal would be for the Authority's rates to be no greater than the equivalent generation rates offered by PG&E. The financial projections included in this Business Plan indicate that in the longer term Program rates are likely to be slightly lower than PG&E's due in part to the Authority's access to low cost generation sources.

Competitive rates will be critical to attracting and retaining key customers, especially the high margin commercial and industrial customers enrolled during Phase 2 that would provide the majority of the Program's revenues. As discussed above, the Program goal is to provide a higher renewable content electricity product at the same rates customers would otherwise pay to PG&E. The financial analysis in Chapter 4 indicates that Program generation rates would need to be approximately 3% higher than PG&E's (about 2% increase in customer electric bills) during the initial Implementation Period, based on PG&E's current rate designs and the pricing offers provided by potential suppliers. The ability to offer competitive rates would be confirmed once firm bids are received from third party suppliers and an analysis is done of PG&E's rates at that time.

For the post Implementation Period, beginning in 2013, it is anticipated the Authority will begin utilizing electricity produced by the proposed community wind project, and this will help to reduce the Program's supply costs and customer rates. As mentioned above, Program rates are projected to be at or slightly below PG&E's rates at that time.

Rate Stability

For the initial three to five years of Program operations, it is anticipated that electricity for the Program would be procured under a fixed price, full requirements contract, so that energy coss become highly predictable. Once operational, the Authority would ensure continuation of stable rates by hedging its supply costs over multiple time horizons. This means that the Program would procure power for the period after expiration of the initial supply contract over a period of years, avoiding the potential for being caught in a high market. Rate stability considerations may mean that rates at any point in time may be slightly higher or lower than PG&E's. Although the Authority's rates would be stabilized through execution of appropriate price hedging strategies, the distribution utility's rates can fluctuate significantly from year-to-year based on energy market conditions such as natural gas prices, the utilities' hedging strategies, and hydro-electric conditions; and from rate impacts caused by periodic additions of generation to utility rate base. Year-to-year rate comparisons will reflect those utility rate variations.

Equity among Customer Classes

The Authority's policy would be to provide comparable rates 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 utilities as well as differences in the costs of providing service to each class. Rates may also vary among customers within the major customer class categories, depending upon the specific rate designs adopted by the Board of Directors. Programs for low income customers are discussed below.

Customer Understanding

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

Revenue Sufficiency

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

Rate Design

The Authority's rate designs would, at least initially, generally mirror the structure of PG&E's generation rates so that similar Program rate impacts can be provided to the Authority's customers. For example, PG&E's residential rates include different rates applicable to five increasing tiers of consumption; as customers use more energy, the rate progressively increases to encourage conservation. The Authority's rates would similarly follow a five-tier structure. Rates for other customer classes include peak demand charges and other charges that vary based on the time period during which the energy or peak demand is consumed (time-of-use rates). The Authority would generally match the rate structures from the utilities' standard rates to avoid the possibility that customers would see significantly different bill impacts as a result of changes in rate structures when beginning service in the Authority's Program. The Authority may also introduce new rate options for customers, such as rates designed to encourage economic expansion or business retention within the Authority's service area.

If the Authority is ultimately able to offer lower rates than PG&E, the proposed rate design approach would apply an equal percentage discount to the otherwise applicable rate for all of the various rate schedules offered by PG&E. If rates are higher, the rate design approach would apply an equal percentage premium to the otherwise applicable PG&E rates. All customers, including low use residential and customers receiving low income discounts would experience the same rate impact on a percentage basis. However, low income customer might be excluded from any rate premiums if Program rates turn out to be higher than PG&E's. While simple in concept, this rate design approach implies a fairly complicated rate structure for the Authority as it matches the rate structures used by PG&E. PG&E's optional "rate ready" billing service, where PG&E calculates bills using the Authority's rates, could not be utilized because PG&E limits the complexity of the CCA rate structure it will accommodate for this service.[38] It would also tend to price services to some customers or during certain time-of-use periods below the Authority's actual cost of providing service. For example, a low use residential customer that used only the minimal baseline usage in a month currently pays less than 5 cents per kWh for generation services, which is below the cost of purchasing the power from the wholesale market. If the Authority discounted all rates equally, the Authority's rate would also be below its costs for some customers, as is currently the case with PG&E's rates.

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

An alternative rate design approach would primarily consider cost of service in setting customer rates and establish a cost based floor below which rates would not be set. The Authority may also simplify rate structures, for instance by eliminating demand charges or reducing/eliminating the residential tier rate structure. Rate comparisons would then vary on a customer-by-customer basis and some customers who the Authority can not cost-effectively serve would have the incentive to remain with PG&E. Such an approach would allow for greater rate benefits for the customers that join the Program because they would no longer be subsidizing others. A simpler, more cost based rate structure would be easier to administer as well. The downside is that the Program would not provide equal benefits to all customers. The initial customer communications effort would be complicated by the inability to provide rate comparisons that would be meaningful and accurate for all customers. Rates for typical customers of each class could be easily compared, but individual customer rate impacts would vary. It should also be understood that a more cost based rate structure would generally favor the commercial and industrial customer classes relative to residential and small commercial customers, and the Program could be faulted for using rate design to exclude small users, even if that is not the intent.[39] A fully cost-based rate design would not be consistent with a goal of maximizing customer participation and providing benefits to all ratepayers. For these reasons, the proposed (equal benefits) rate design described above is recommended.

Net Energy Metering

Customers with on-site generation eligible for net metering from PG&E would be offered a time differentiated, net energy metering rate from the Authority. Net energy metering allows for customers with certain qualified solar or wind distributed generation to be billed on the basis of their net energy consumption. PG&E's net energy metering tariff gives customers the opportunity to net their energy consumption over the course of a calendar year. Recent CPUC

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

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

decisions have made CCA customers ineligible for continued service on the utilities' net energy metering tariffs, pending proposals that may be made by a CCA for how to treat net energy metering customers.[40] The Authority's objective is for the Authority's net energy metering tariff to apply to the generation component of the bill, and for the utility's net energy metering tariff to apply to the utility's portion of the bill. To the extent that current CPUC regulations governing provision of net energy metering to CCA customers are unresolved, the Authority would work with PG&E and the CPUC to establish a net energy metering tariff that accomplishes this objective.

The CCA could also offer to purchase excess generation from net metered accounts. PG&E currently does not provide any credit for excess production at the end of the calendar year.

Low Income Rates

The existing rate discounts for low income customers participating in the California Alternate Rates for Energy (CARE) Program will be maintained for customers that enroll in the CCA Program. The delivery charges for CARE customers are reduced to reflect the discounts. These customers would continue to see the same discount whether they remain as a PG&E bundled service customer or become a customer of the CCA. The Authority may also establish additional low income rate programs at its discretion.

Rate Impacts

The estimated class average electric rates for the initial phase customers are shown in the following table. The projected rates shown below are consistent with a price for full requirements electric supply of approximately 8.3 cents per kWh. ***These rates are illustrative, based on market quotes as of February 2007; the ability to offer the targeted rates must still be confirmed through the RFP process described in Chapter 6.***

Table 41: Estimated 2010 Program Rates[41]

[40] Under current rules, the customer bill would be calculated based on the net energy consumed during the month, but the customer would not be able to net consumption from one month to the next as allowed by PG&E's net energy metering tariff (E-NEM).

[41] Includes Energy Cost Recovery Amount component of the Cost Responsibility Surcharge.

CUSTOMER CLASS	PROGRAM RATES, GENERATION ONLY – (CENTS PER KWH)
Residential	8.7
Small Commercial	9.6
Medium Commercial	9.4
Medium Industrial	8.7
Large Industrial	8.2
Agricultural	8.9
Street and Area Lighting	8.1

Individual customers within rate classes may pay higher or lower average rates than those shown above depending on their electricity usage and load profile. The Authority's rates shown include all costs expected to be incurred by the Authority related to the aggregation Program, including power supply costs, operations and administration costs, reserves, and billing and metering fees charged by PG&E to the Authority. The rates shown above also include the cost responsibility surcharges that the Authority's customers would pay directly to PG&E, with the exception of the DWR bond charge component.

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 Authority would prepare an annual budget and corresponding customer rates and submit these as an application for a change in rates to the Board of Directors. The rates would be approved at a public meeting of the Board of Directors no sooner than sixty days following submission of the proposed rates, during which affected customers would be able to provide comment on the proposed rate changes. Public workshops would be held prior to the Board making decisions regarding proposed rate increases or investments in electric generating facilities.

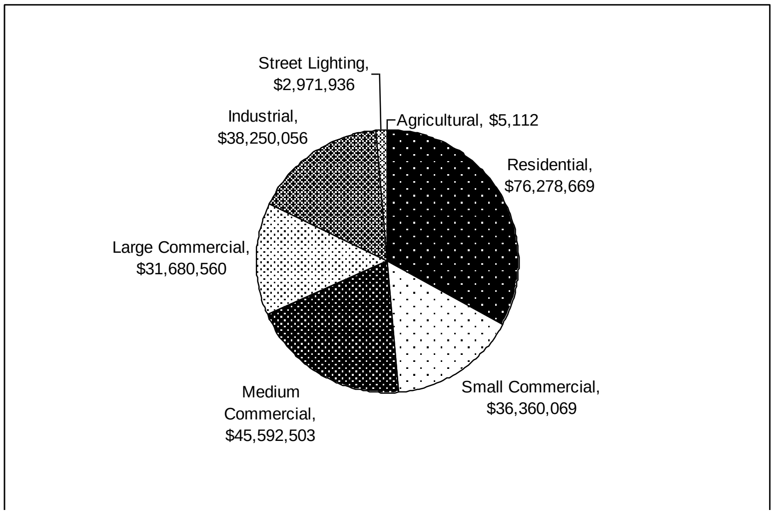
The Authority would initially adopt customer noticing requirements similar to those the CPUC requires of PG&E and SCE. These notice requirements are described as follows:

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

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

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

Figure 11: Projected 2011 Revenues by Customer Class (Dollars) [42]



Focused marketing efforts should be directed to the Phase 2 customers to encourage their participation in the Program. Early in the Program's startup process, efforts should target the top 25 to 50 customers (primarily E-20 customers) that would be responsible for more than 15% of Program revenues, with the goal of negotiating term contracts which would ensure their participation in the Program and provide price certainty benefits to these customers.

Customer Rights and Responsibilities

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

Customer Notices

The Program will be initiated with a broad community outreach and communications plan. In addition, a total of four notices would be provided to customers describing the Program, informing them of their opt-out rights to remain with utility bundled generation service, and containing a simple mechanism for exercising their opt-out rights. The first notice will be mailed to customers approximately sixty days prior to the date of automatic enrollment. A

[42] The sales projections exclude customers currently taking direct access service or customers such as UC Berkeley and the Lawrence Livermore Laboratory, that are otherwise not taking full "bundled" service from PG&E.

second notice will be sent approximately thirty days later. The Authority would likely use its own mailing service for the initial opt-out notices rather than including the notices in PG&E's monthly bills. This is intended to increase the likelihood that customers will read the opt-out notices, which may otherwise be ignored if included as a bill insert. As required by CPUC regulations, the Authority will use PG&E's opt-out processing service. Customers may opt out by notifying PG&E using the utility's automated telephone system or internet opt out processing services. Consistent with CPUC regulations, notices returned as undelivered mail would be treated as a failure to opt out, and the customer would be automatically enrolled.

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

New customers who establish service within the Program service area would be automatically enrolled in the Program and would have sixty days from the date of enrollment to opt out of the Program. Such customers would be provided with two opt-out notices within this sixty-day post enrollment period. 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 Exit Fees described below would apply. Program customers that move out of the Program's service territory would not be subject to the Program's Exit Fees.

The Authority's Board of Directors would have the authority to implement entry fees for customers that initially opt out of the Program, but later decide to participate. Entry fees would help prevent potential gaming, particularly by large customers, and aid in resource planning by providing additional control over the Program's customer base. Entry fees would not be practical to administer, nor would they be necessary, for residential and other small customers.

Exit Fee

Customers that are automatically enrolled in the Program can elect to transfer back to the incumbent utility without penalty within the first two billing cycles of service. After this free opt-out period, customers would be allowed to terminate their participation subject to payment of a Exit Fee. The Exit Fee would apply to all Program customers within the Program service territory that elect to return to bundled utility service or elect to take "direct access" service from an energy services provider.

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

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

Table 42: Administrative Fee for Service Termination

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

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

The financial projections contained in Appendix D indicate that the Authority's rates are expected to be very close to those charged by PG&E over the long term and that the Authority's supply portfolio is projected to be competitive in the marketplace because of the financing advantages that the Authority enjoys. Under those conditions, most customers would not be expected to terminate their service with the Authority to return to the utility. Furthermore, if customers do terminate service, the Authority should be able to re-market the excess supply and fully recover its costs. Although the Cost Recovery Charge will likely not be needed for recovery of stranded costs, the Authority's ability to assess a Cost Recovery Charge, if necessary, is an important condition for obtaining financing for the Authority's power supply. The low cost financing will, in turn, enable the Authority to charge rates that are competitive with PG&E's. The CRC will also enhance the credit profile of the Program as it relates to credit exposure from the electricity suppliers' point of view. Absent a CRC, the Program would likely need to post cash collateral to match its credit exposure to the Program's electric supplier(s).

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

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

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

Customer Confidentiality

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

Responsibility for Payment

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

Customer Deposits

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

Current regulations do not require that PG&E transfer customer deposits to the CCA. The Authority should make every effort to get a share of customer deposits held by PG&E (whose credit exposure is reduced) transferred to the Authority as opposed to requiring a second deposit.

CHAPTER 6 - Procurement Process

Introduction

This Chapter describes the Authority's initial procurement policies and the key third party service agreements by which the Authority would obtain operational services for the CCA Program. The Authority's Board of Directors would approve its general procurement policies set forth in an adopted Implementation Plan to be effective at Program initiation. Procurement policies will be consistent with the rules of the member jurisdiction that the Authority used for its powers. The Board of Directors would retain authority to modify Program policies from time to time at its discretion.

Procurement Methods

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

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

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

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

Procurement at Startup

The operational services needed for the Program should be competitively procured. In January, 2007, a non- binding request for information was released seeking statements of qualifications and indicative cost proposals for energy supply and certain customer service related functions. The indicative pricing information provided by respondents to the request for information is incorporated in this business plan.

Assuming the Authority is formed, a binding request for bids would be issued some time in the first quarter of 2009 to solicit bids for electric supply and customer account services needed for Program operations. Firm energy price bids will be solicited for the first three to seven years of operations. The selected supplier will be required to have extensive operational experience and must maintain an investment grade credit rating to minimize risks of default. The supplier will be responsible for managing the electric supply portfolio on behalf of the Authority and will be required to meet the renewable portfolio requirements specified by the Authority as well as other applicable regulatory requirements such as those pertaining to resource adequacy. During this period, the bulk of the risks will be borne by the third party supplier under a "full requirements" electric supply contract, which would include provisions for integrating the planned renewable resource if the contract extends beyond 2012.

As a result of the competitive solicitation, electric supply costs will be known for the first three to seven years of Program operations based on the firm bids offered by the selected supplier. Bids for customer services needed for the Program (Customer Account Services) should also be obtained via a competitive solicitation. The Cities' evaluation of whether to proceed with implementation will therefore incorporate known costs for approximately 95% of total Program costs for the first three years to seven years, providing relative certainty regarding the ability to provide competitive rates. Based on the firm bids, a determination will be made regarding whether the Program can provide ratepayer benefits during the Implementation Period. If the Program cannot provide competitive rates, a determination would be made whether to adjust the timing for implementation or terminate the Program altogether.

Key Contracts

Electric Supply Contract

For the initial three years of Program operations (1/1/2010 through 12/31/2012), a third party energy services provider would supply electricity to customers under a full requirements contract. Under a full requirements contract, the supplier commits to serve the total electrical loads of customers in the CCA Program. If the initial contract extends beyond 2012, it should also include provisions for integration of any generation resources developed by the Authority. The supplier would be responsible for ensuring that a certified Scheduling Coordinator schedules the loads of all customers in the Program and would also be responsible for obtaining meter data from PG&E to submit to the CAISO settlement process. The supplier would be wholly responsible for the portfolio operations functions and managing all supply risks for the term of the contract. The supplier must meet the Program's renewable energy goals and comply with all resource adequacy and other regulatory requirements imposed by the CPUC or FERC. The Authority should require the Program supplier to maintain an investment grade credit rating during the term of the agreement, and the contract should specify that failure to do so would require additional credit support from the supplier. This provision requires a continual credit monitoring of the supplier. An additional credit support mechanism that could be used would be for the supplier to provide a performance bond. It is estimated that the cost of the performance bond could range from 0.25% to 0.5% of the credit exposure. For the initial three year implementation period, the cost of a performance bond equates to a range of $1.2 to $2.4 million.

Risks related to customer opt-outs and changes in Program loads during the term of the agreement are generally borne by the supplier, subject to negotiated bandwidths outside which pricing may be adjusted. The supplier would be given the opportunity to charge different prices for sales to the various customer classes to help mitigate opt-out risks related to uncertainty in the load profile of the final customer mix. These prices would be an input to the Program's overall costs, but the Authority would establish customer rates.

The supplier would also be required to specify the renewable content of the supply portfolio that will be used to supply the Program for each year of the agreement term. A preference would be given to local renewable energy resources and energy efficiency projects. Renewable energy disclosed must qualify to meet the California RPS and would be no less than the percentages discussed in Chapter 3.

Data Management Contract

A data manager would provide the retail customer services of billing and other customer account services (EDI with PG&E, billing, remittance processing, 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 would be selected to perform all of the data management functions.[43]

The data manager is responsible for the following services:

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

Utilizing a third party for account services eliminates a significant expense associated with implementing a customer information system. Such systems can cost from five to ten million

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

dollars to implement and take significant time to deploy. A longer term contract is appropriate for this service because of the time and expense that would be required to migrate data to a new system. Separation of the data management contract from the energy supply contract gives the Authority greater flexibility to change energy suppliers, if desired, without facing an expensive data migration issue.

The Authority should issue a request for proposals from contactors for each of these roles through a competitive solicitation process. A short list of potential energy suppliers and data management providers selected as a result of this process should reflect a highly qualified pool of suppliers for further negotiations, which will be completed prior to registration of the CCA. The proposed timeline for the initial solicitation is as follows:

Table 43: Timeline For Solicitation of Supply and Account Management Services

Action	**Date**
Release Request For Proposals	February 2009
Selection of supplier(s)	April, 2009
Contract Execution	July 2009
Commence Service	January, 2010

Chapter 7 - Contingency Plan For Program Termination

Introduction

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

Termination by Authority

The Authority would plan to offer services for the long term with no planned Program termination date. In the unanticipated event that the Authority's Board decides to terminate the Program and any applicable restrictions on such termination have been satisfied, notice would be provided to customers six months in advance that they will be transferred back to PG&E. A second notice would be provided during the final sixty-days in advance of the transfer. The notice would describe the applicable distribution utility bundled service requirements for returning customers then in effect, such as any transitional or bundled portfolio service rules.

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

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

Termination by Members

The JPA Agreement will define the terms and conditions under which Members may terminate their participation in the Program. As described in the proposed JPA Agreement (Appendix A), Members could withdraw from the Authority upon six months written notice provided that such Members would be obligated to pay their pro-rata share of all encumbrances and indebtedness of the Authority as of the date of served notice of termination on the Authority. As a consequence of a Member's withdrawal from the Authority, customers within the Member's jurisdiction would be returned to PG&E bundled service at their regularly scheduled meter read date prior to the effective date of the Member's withdrawal from the Authority, following the 60-day notice period described above.

In accordance with PG&E's CCA tariff, the Authority would execute a revised service agreement or specialized service agreement, as appropriate, with PG&E to coordinate the removal of the withdrawing Member from the CCA program.

CHAPTER 8 – Appendices

Appendix A: **Proposed Joint Powers Agreement and Principals for CCA Project Agreement**

Appendix B: **Proposed Renewable Generation Projects Sample Renewable Solicitations**

Appendix C: **Energy Efficiency Potential**

Appendix D: **Pro Forma 2013 – 2026**

Appendix E: **Risk Analysis Report**

Appendix F: **Sample Renewable Energy Solicitations**