

**SAN JOAQUIN VALLEY  
POWER AUTHORITY**

**COMMUNITY CHOICE  
AGGREGATION  
IMPLEMENTATION PLAN  
AND STATEMENT OF INTENT**

**April 2007**

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## I. INTRODUCTION

### A. Overview

The San Joaquin Valley Power Authority (Authority) is a public agency comprised of twelve member cities and one county formed for the purposes of implementing a community choice aggregation (CCA) program serving the greater Fresno region of the San Joaquin Valley. This Implementation Plan describes the Authority's plans to implement a voluntary CCA Program for electric customers within the jurisdictional boundaries of its Member cities and Kings County (Members) that currently take bundled electric service from Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE), collectively. The CCA Program will give electricity customers the opportunity to join together to procure electricity from competitive suppliers, with such electricity being delivered over PG&E's and SCE's transmission and distribution systems. The planned start date for the Program is November 1, 2007 (subject to the final review and approval of the Authority's Board). All current PG&E and SCE customers within the Authority's service area will receive information describing the Program and will have multiple opportunities to express their desire to remain full requirement customers of PG&E or SCE, in which case they will not be enrolled in the Program. Thus, participation in the CCA Program is completely voluntary; however, customers, as provided by law, will be automatically enrolled unless they affirmatively elect to opt-out of the CCA Program.

The Authority's primary objective in implementing this Program is to enable customers within its service area to take advantage of the opportunities granted by Assembly Bill 117 (AB 117), the Community Choice Aggregation Law. The benefits to consumers include the ability to reduce energy costs; stabilize electric rates; increase local electric generation reliability; influence which technologies are utilized to meet their electricity needs (including a potential increased utilization of renewable energy); ensure effective planning of sufficient resources and energy infrastructure to serve the Members' residents and businesses; and improve the local/regional economy.

Because providing retail electric service can be a complex undertaking and the Authority has no operational experience in procuring electricity for retail customers, the Authority will receive assistance from experienced energy suppliers and contractors in providing energy services to Program customers. The Kings River Conservation District (KRCD) will act as the exclusive agent on behalf of the Authority and will provide all power services to the Authority, utilizing KRCD staff as well as private sector contractors and qualified energy suppliers.

KRCD was formed under the Kings River Conservation District Act of 1951 (Cal. Stats. 1951, Chapt. 59; West Water Code App.) Today, KRCD is a leading resource management agency for the Kings River region serving agriculture, business and residential communities within 1.2 million acres spanning portions of Fresno, Kings and Tulare counties. The mission of KRCD is to provide flood protection, cooperate with

other agencies to achieve a balanced and high quality water supply, and develop power resources in the Kings River area for the public good. KRCD is the owner/operator of the 165-MW Jeff L. Taylor Pine Flat Hydro-Electric Power Plant and the 97-MW Malaga Peaking Plant. KRCD is currently in the permitting process of a nominal 500 MW base-load natural gas-fired power plant as well as preliminary development of local renewable resource projects.

The Authority's Implementation Plan reflects a collaborative effort among the Authority, its Members, KRCD, and the private sector to bring the benefits of competition and choice to Member residents and businesses. By exercising its legal right to form a CCA Program, the Authority will enable its Members' constituents to access the competitive market for energy services and obtain access to low cost electricity from KRCD owned and planned resources. Absent action by the Authority or its individual Members, customers currently taking generation service from the utilities would have no ability to choose an electric supplier and would remain captive customers of their incumbent utilities.

The California Public Utilities Code provides the relevant legal authority for the Authority to become a Community Choice Aggregator and invests the California Public Utilities Commission (CPUC or Commission) with the responsibility for establishing the cost recovery mechanism that must be in place before customers can begin receiving electrical service through the Authority's CCA Program. The CPUC also has responsibility for registering the Authority as a Community Choice Aggregator and ensuring compliance with basic consumer protection rules. The Public Utilities Code requires that an Implementation Plan be adopted at a duly noticed public hearing and that it be filed with the Commission in order for the Commission to determine the cost recovery mechanism to be paid by customers of the Program in order to prevent shifting of costs. Each of these milestones has been accomplished. On January 25, 2007, the Authority, at a duly noticed public hearing, considered and adopted its Implementation Plan, through SJVPA Resolution No. 07-01 (a copy of which is included as part of Appendix A), and the Implementation Plan was submitted to the CPUC on January 29, 2007. In Decisions D.04-12-046, D.06-12-041 and D.07-01-025, the Commission established the methodology that will be used to determine the cost recovery mechanism, and PG&E and SCE now have approved tariffs for imposition of the cost recovery mechanism. Finally, each of the Authority's Members has adopted an ordinance to implement a CCA program through its participation in the Authority (copies of individual ordinances are included as Appendix A). Following the CPUC's certification of its receipt of the Implementation Plan and resolution of any outstanding issues, the Authority will take the final steps needed to register as a CCA prior to initiating the customer notification and enrollment process.

As the Implementation Plan is modified from time to time, the Authority will maintain a current version of the Implementation Plan on file with the CPUC. The first

modifications to the Authority's Implementation Plan were adopted on April 12, 2007 pursuant to SJVPA Resolution No. 07-04.

***B. Organization of this Implementation Plan***

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

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

The remainder of this Implementation Plan is organized as follows:

Chapter II: Aggregation Process

Chapter III: Organizational Structure

Chapter IV: Startup Plan and Funding

Chapter V: Program Phase-In

Chapter VI: Load Forecast and Resource Plan

Chapter VII: Financial Plan

Chapter VIII: Ratesetting

Chapter IX: Customer Rights and Responsibilities

Chapter X: Procurement Process

Chapter XI: Contingency Plan for Program Termination

Appendix A: Authority Resolution 07-01 and Authority Member Ordinances

Appendix B: Joint Powers Agreement

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

**Table 1**  
**AB 117 Cross References**

<b>AB 117 REQUIREMENT</b>	<b>IMPLEMENTATION PLAN CHAPTER</b>
Process and consequences of aggregation	<i>Chapter II: Aggregation Process</i>
Organizational structure of the program, its operations and funding	<i>Chapter III: Organizational Structure Chapter IV: Startup Plan and Funding Chapter VII: Financial Plan</i>
Ratesetting and other costs to participants	<i>Chapter VIII: Ratesetting Chapter IX: Customer Rights and Responsibilities</i>
Disclosure and due process in setting rates and allocating costs among participants	<i>Chapter VIII: Ratesetting</i>
Methods for entering and terminating agreements with other entities	<i>Chapter X: Procurement Process</i>
Participant rights and responsibilities	<i>Chapter IX: Customer Rights and Responsibilities</i>
Termination of the program	<i>Chapter XI: Contingency Plan for Program Termination</i>
Description of third parties that will be supplying electricity under the program, including information about financial, technical and operational capabilities	<i>Chapter X: Procurement Process</i>
Statement of Intent	<i>Chapter I: Introduction</i>

## II. AGGREGATION PROCESS

### A. Introduction

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

The Authority's efforts to form a CCA Program began with the development of a memorandum of understanding (MOU) dated March 1, 2005, between the Members of the Authority and KRCD. The MOU provided for a detailed feasibility study concerning CCA. The Feasibility Study, completed in September 2006, found that there were numerous benefits (and certain risks) for the Authority's Members to further develop and ultimately implement a CCA Program. The MOU Parties retained an independent energy consulting firm to perform a "peer review" of the Feasibility Study. This peer review generally agreed with the analysis and conclusion of the Feasibility Study, and also recommended that the MOU Parties continue with the development of a CCA Program.

Following consideration of the feasibility study results, a draft of the Implementation Plan was developed and reviewed with each of the Authority's Members. The Authority's Members include:

City of Clovis	City of Kingsburg	Kings County
City of Corcoran	City of Lemoore	
City of Dinuba	City of Parlier	
City of Fresno	City of Reedley	
City of Hanford	City of Selma	
City of Kerman	City of Sanger	

After its review of the draft Implementation Plan, each Member subsequently adopted an ordinance declaring its election to implement a CCA program by and through the City/County's participation in the Authority as described herein. The draft Implementation Plan was also published on the Community Choice website<sup>1</sup> and was made available at offices of the Authority. Any person was able to view the draft Implementation Plan and provide comments for consideration in the final version. The Implementation Plan was adopted at a duly noticed public hearing of the Authority on January 25, 2007 and modifications to the Implementation Plan were adopted on April 12, 2007.

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<sup>1</sup> [www.communitychoice.info](http://www.communitychoice.info)

**B. Process of Aggregation**

Before customers are enrolled in the Program, customers will receive two written notices in the mail, from the Authority, that will provide information needed to understand the Program’s terms and conditions of service and explain how customers can opt-out of the Program, if desired. All customers that do not follow the opt-out process specified in the customer notices will be automatically enrolled, and service will begin at their next regularly scheduled meter read date following the date of automatic enrollment, subject to the service phase-in plan described in Chapter V. The initial opt-out notices will be provided to the first phase of customers in September 2007. The initial opt-out notices will be provided to the remaining phases of customers (phases 2, 3, and 4) 60 days prior to commencement of service to each phase of customers. The follow-up opt-out notices will be provided within the first two months of service for each of the phases.

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

Customers will be given two additional opportunities to opt-out of the Program and return to their respective distribution utility (PG&E or SCE) following cutover of service. Customers that opt-out between the initial cutover date and the close of the post enrollment opt-out period will be responsible for program charges for the time they were served by the Authority but will not otherwise be subject to any penalty for leaving the program. Customers that have not opted-out within sixty days of cutover to CCA service will be deemed to have elected to become a participant in the Program and to have agreed to the Program’s terms and conditions, including those pertaining to requests to terminate service, as further described in Chapter VIII.

New customers who establish service within the Program service area will be automatically enrolled in the Program and will have sixty days from the date of enrollment to opt out of the program. Such customers will be provided with two opt-out notices within this sixty-day post enrollment period.

A high level process overview and timeline for Aggregation is shown in Table 2.

**Table 2  
Aggregation Process**

<b>ACTIVITY</b>	<b>TIMELINE</b>
Implementation Plan filed with CPUC	Day 0
CPUC certifies receipt of Implementation Plan	Day 90
Authority executes power services agreement with	Day 120

ACTIVITY	TIMELINE
Power Services Provider	
Authority executes service agreement with PG&E and SCE	Day 150
Authority provides binding notice of intent to PG&E and SCE	Day 150
Authority submits registration package to CPUC	Day 165
Authority finalizes initial rates	Day 165
Authority customer outreach and pre-enrollment opt-out notices	Day 180 – 210
Automatic enrollment of customers that have not opted out	Day 270
Customers switched to CCA service on next scheduled meter read date	Day 270 - 300
Post enrollment opt-out notices	Day 330 – 360

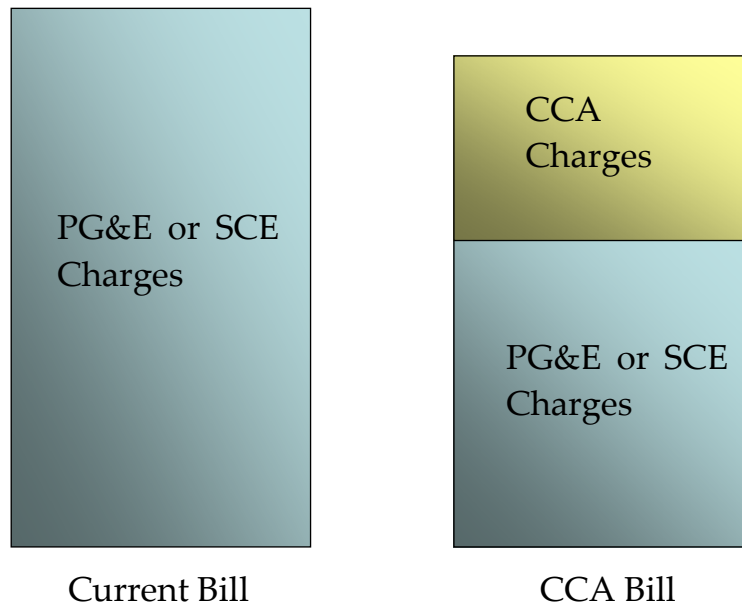
### *C. Consequences of Aggregation*

#### 1. Rate Impacts

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

The Authority’s rate setting policies described in Chapter VII establish a goal of providing rates that are lower than the equivalent generation rates offered by the incumbent distribution utility (PG&E or SCE) (targeted initially at a five percent discount with the discount potentially increasing once additional KRCD-owned resources are brought on-line). The Authority will establish rates sufficient to recover all costs related to operation of the Program, and actual rates will be adopted by the Authority’s governing board. The projected impact on customer bills of joining the Program, based on indicative supplier costs, is illustrated in Figure 1.

**Figure 1**  
**Changes in Customer Bills**



The total electric rate will be reduced for customers if the Program is successful in obtaining electric generation at a lower cost than charged by the current distribution utility. Initial Program rates will be established following approval of the Authority's inaugural program budget, reflecting final costs from the Program's energy supplier(s). Based on information provided by the expected electricity supplier, the Authority expects to charge rates initially approximately five percent below those charged by PG&E and SCE. The Authority's rate policies and procedures are detailed in Chapter VII. Information regarding final Program rates will be disclosed along with other terms and conditions of service in the pre-enrollment opt-out notices sent to potential customers.

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

## 2. Renewable Energy Impacts

A second consequence of the Program will be an anticipated increase in the proportion of energy generated and supplied by renewable resources. The resource plan includes procurement of renewable energy sufficient to meet up to 20 percent or more of the Program's electricity needs. Initially, this renewable energy will be met contractually, potentially from new renewable resources, which will be complemented by the

development of new renewable generation resources by or for the Authority. The Program will start from a baseline of 0 percent, and the full amount of the 20 percent renewable target will likely be incremental renewable supply.

### 3. Energy Efficiency Impacts

A third consequence of the Program will be an increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by the distribution utilities are not expected to change as a result of the Authority forming the Program. CCA customers will continue to pay the public goods charges to the distribution utilities which fund energy efficiency programs for all customers, regardless of generation supplier. The energy efficiency investments ultimately planned for the Program, as described in Chapter V, will be in addition to the level of investment that would continue in the absence of the Program. Thus, the Program has the potential for increased energy savings and a further reduction in emissions due to expanded energy efficiency programs.

### III. ORGANIZATIONAL STRUCTURE

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

#### *A. Organizational Overview*

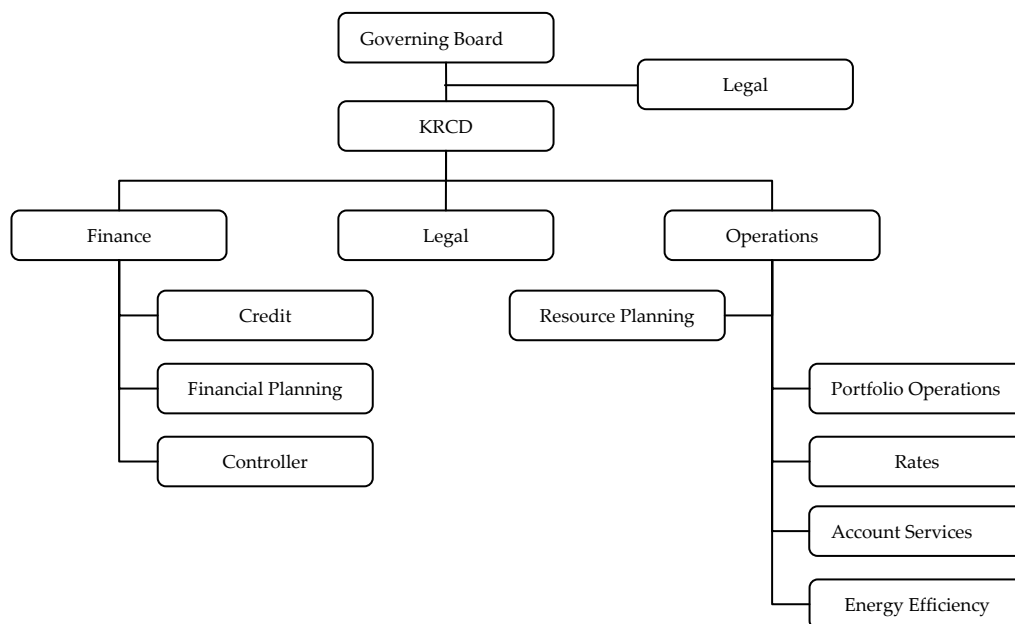
The Program will be governed by the Authority's Board of Directors, appointed by the Members. The Authority is a joint exercise of powers agency created on November 15, 2006 and formed under California law. Twelve cities and one county that have elected to offer the Program to their constituents have become Members of the Authority. The Authority is the CCA entity that will register with the CPUC, and it is responsible for implementing and managing the program pursuant to the SJVPA Joint Powers Agreement (a copy of which is included as Appendix B). The Program will be operated under the direction of the Authority's Power Services Provider, KRCD. KRCD will report to the Authority's Board of Directors (Governing Board), which is comprised of one representative from each participating Member of the Authority.

The Governing Board's primary duties are to establish program policies, set rates and provide policy direction to KRCD, who will have general responsibility for program operations, consistent with the policies established by the Governing Board. The Governing Board is responsible for evaluating KRCD's performance as the Power Services Provider and is ultimately responsible for managing the agreement with KRCD. The Authority will maintain a separate legal function as well to support its ongoing governance and administration.

The Governing Board may also establish an Executive Committee and other committees and sub-committees as needed to address issues that require greater expertise in particular areas (e.g., finance or contracts). The Joint Powers Agreement included in Appendix B defines the terms and conditions by which the Authority will be governed.

KRCD has responsibilities over the functional areas of Finance, Regulatory, and Operations. In performing its obligations to the Authority, KRCD will utilize a combination of internal staff and contactors. Certain specialized functions needed for program operations, namely, the electric supply and customer account management functions described below, will be performed initially by experienced third party contractors. The Program organizational chart showing relationships among the Governing Board, KRCD and the functional areas is shown in Figure 2.

**Figure 2  
Program Organization**



**B. Governance**

The Governing Board will consist of one representative (Director) from each of the Members. The Governing Board will meet at regular intervals to provide the overall management and guidance for the Authority.

Decisions by the Authority will be under voting procedures defined in the Joint Powers Agreement. All votes on a particular matter are subject to a two-tier approval process: first, any decision must be approved by a simple majority of the Directors at the Governing Board meeting; second, assuming the first requirement is reached, those Directors voting in the affirmative must constitute over 50 percent of a weighted voting percentage comprised of equal treatment of a Participant’s electricity requirements and a pro rata percentage. That is, one-half of the combined vote is based upon the total number of Members (i.e., 13 Members each receive 3.85 percent [50%/13]) and one-half of the combined vote is based upon annual electric usage. Table 3 is illustrative of the voting percentages for the **second tier** vote.

**Table 3**  
**Voting Percentages for the Second Tier Vote**

<b>Member</b>	<b>Estimated Percent of Total Program Load</b>	<b>Load Voting Percentage (50%)</b>	<b>Pro Rata Percentage (50%)</b>	<b>Total Voting Percentage (Tier 2)</b>
Clovis	9.5%	4.74%	3.85%	<b>8.59%</b>
Corcoran	2.3%	1.15%	3.85%	<b>5.00%</b>
Dinuba	1.0%	0.50%	3.85%	<b>4.34%</b>
Fresno	56.9%	28.46%	3.85%	<b>32.30%</b>
Hanford	5.3%	2.67%	3.85%	<b>6.52%</b>
Kerman	0.8%	0.40%	3.85%	<b>4.24%</b>
Kings County	11.6%	5.79%	3.85%	<b>9.63%</b>
Kingsburg	1.2%	0.58%	3.85%	<b>4.43%</b>
Lemoore	3.9%	1.94%	3.85%	<b>5.78%</b>
Parlier	1.3%	0.66%	3.85%	<b>4.51%</b>
Reedley	2.1%	1.07%	3.85%	<b>4.92%</b>
Sanger	2.0%	1.01%	3.85%	<b>4.85%</b>
Selma	2.0%	1.02%	3.85%	<b>4.87%</b>
	100%	50.0%	50.0%	<b>100.00%</b>

1. Officers

The Governing Board will have a Chair and Vice-Chair elected from among the Directors to one-year terms. In addition, the Authority will have a Secretary, and Treasurer/Auditor. The Joint Powers Agreement provides further details on each of these positions.

2. Committees

The Authority may elect to have committees or working groups to address various topics. Specific committees and their functions will be determined by the Governing Board at the time of the committee's creation.

3. Addition/Termination of Participation

The Joint Powers Agreement provides for the addition of new Members subject to the affirmative vote of the Governing Board pursuant to the voting structure described above.

A Member can withdraw itself from the Authority subject to the terms and conditions contained in the Joint Powers Agreement. Essentially, the withdrawing Member needs to provide the Authority with reasonable notice of its intent to withdraw and the withdrawing Member will be subject to all reasonable ongoing costs incurred by the Authority on behalf of that entity.

As of the filing date of this Implementation Plan, Tulare County is in the process of evaluating its options of requesting membership in the Authority. If Tulare County elects to request membership, the Governing Board will consider Tulare County's participation and will be the ultimate decision making entity on permitting Tulare County's membership. The Authority's Implementation Plan would be revised in the event that its membership is expanded by the addition of Tulare County.

### *C. Agreements Overview*

There are three principal agreements that will govern the Authority and its CCA Program: the Joint Powers Agreement; Program Agreement No. 1 (PA-1); and the Power Services Agreement (PSA). Each of these agreements and its functions are discussed below.

#### 1. Joint Powers Agreement

The Joint Powers Agreement (included as Appendix B) creates the Authority and provides it with broad powers related to the study, promotion, development, and conduct of electricity-related projects and programs. The Joint Powers Agreement provides for participation by all cities and the county that executed the MOU and also provides for future participants.

The Joint Powers Agreement describes the Authority as having broad authorities and powers, but a very limited role without implementing agreements to carryout specific programs. PA-1, discussed in greater detail below, provides for the development, implementation and operation of a CCA Program. At the Members' discretion, future program agreements could provide for other energy-related programs. The Joint Powers Agreement provides for the governance of the Authority, as discussed above.

#### 2. Program Agreement No. 1

PA-1, which is under development by the Authority, represents the final commitment of all Members to participate in the CCA Program. Failure by a Member to execute PA-1 will lead to that Member's withdrawal from the Authority. PA-1 is expected to be executed in the April to June 2007 timeframe.

#### 3. Power Services Agreement

The Authority will enter into a PSA with KRCD to provide the management, power supply, staffing, and day-to-day operation of the CCA Program. Under the PSA, KRCD will procure (or develop) the necessary energy to supply the Authority's loads, enter into agreements with vendors to provide services (e.g., scheduling coordinator, data management, regulatory support), and manage the overall CCA Program. The Governing Board will direct, provide guidance, and evaluate the performance of KRCD in this function.

#### ***D. Authority Operations***

The Authority does not anticipate having any staff of its own. Rather, pursuant to the proposed Power Services Agreement, the Authority will contract with KRCD to serve as the full-service provider to the Authority. It is anticipated that KRCD will fill this role both through its own internal staff and through contracting for services with third parties. One area that will not be handled by KRCD is the provision of legal advice to the Authority; the Authority will have its own General Counsel.

Major Authority functions that will be performed and managed by KRCD are summarized below.

##### **1. Resource Planning**

KRCD will be charged with developing both short (one and two-year) and long-term resource plans for the Authority. KRCD will develop the resource plan under the guidance provided by the Governing 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 10- to 20-year time horizon. KRCD'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. This will ensure that local preferences regarding the future composition of supply and demand resources are planned for, developed, and implemented.

##### **2. Portfolio Operations**

Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These 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 California Independent System Operator (CAISO).

KRCD 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 third party that will be supplying electricity under the program, including information about financial, technical and operations capabilities, is contained in Chapter X.

The Authority will approve and adopt a set of Program Controls that will serve as the risk management tools for KRCD and any third party involved in the Authority portfolio operations.

### 3. Energy Efficiency

A key focus of the CCA Program will be the development and implementation of an energy efficiency program for the Members. A preliminary approach for a future energy efficiency program is discussed in chapter VIII. KRCD will be responsible for further development of the energy efficiency portion of the CCA 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 will administer energy efficiency and demand response programs that can be used as cost-effective alternatives to procurement of supply-side resources. The Authority will attempt to consolidate existing demand side programs into this organization and leverage the structure to expand energy efficiency offerings to customers throughout its service territory, potentially through the CPUC application process for third party administration of energy efficiency programs and other demand-side management techniques.

### 4. Rate Setting

The Governing Board will have the ultimate responsibility for setting the electric generation rates for its customers. KRCD will develop proposed rates and options for the Governing Board to consider before the finalization of the actual rates. The final approved rates must, at a minimum, meet the annual revenue requirement developed by KRCD. The Governing 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.

### 5. Financial Management/Accounting

Managing the overall financial function of the CCA Program is expected to be a significant work activity. KRCD will be responsible for managing this function 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 function plays an important program risk management function of 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. The Finance function establishes credit policies that the program must follow.

It is planned that the settlements (customer billing) will be contracted out to an organization with the necessary infrastructure and capability to handle potentially over 300,000 accounts. This function is described under Customer Services, below.

#### 6. 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. Pursuant to the anticipated Power Services Agreement, KRCD will be responsible for the Customer Services function. KRCD will contract with a third party service provider for certain billing-related or "Customer Account Services" as described below.

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. KRCD will 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.

KRCD will 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 awareness and 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.

**7. Legal and Regulatory Representation**

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

The Authority will retain legal services, as necessary, to administer the Authority, review contracts, and provide overall legal support to the activities of the Authority. KRCD will be responsible for legal support related to program operations and its role as the Authority’s Power Services Providers. The Authority’s General Counsel and KRCD’s regulatory counsel are expected to work closely to represent the Authority in various forums.

***E. Roles and Functions***

The Authority and KRCD will perform the functions inherent in its policy-making, management and planning roles. The Authority and KRCD will 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, will be contracted out to third parties with sufficient experience, technical and financial capabilities. The functions that will initially be performed by the Authority, KRCD and third parties are specified below:

<b><u>Organization</u></b>	<b><u>Roles/Functions/Activities</u></b>
Authority	<i>Executive/Policy/Legal</i>
KRCD	<i>Finance</i>
	<i>Legal and Regulatory</i> <ul style="list-style-type: none"> <li>- <i>Legal support</i></li> <li>- <i>Participation in regulatory proceedings</i></li> <li>- <i>Regulatory reporting</i></li> </ul>
	<i>Marketing/Communications</i>
	<i>Rates &amp; Support</i> <ul style="list-style-type: none"> <li>- <i>Rate policy</i></li> <li>- <i>Rate design</i></li> <li>- <i>Cost-of-service planning</i></li> </ul>
	<i>Resource Planning</i> <ul style="list-style-type: none"> <li>- <i>Load research</i></li> <li>- <i>Load forecasting</i></li> <li>- <i>Supply-side/Demand side portfolio planning</i></li> </ul>

<u>Organization</u>	<u>Roles/Functions/Activities</u>
	Contract Management
	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 - Payment processing - Billing and retail settlements - Call center

In its role as the Power Services Provider to the Authority, KRCD will 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. KRCD selected its third party electric supplier through a competitive solicitation. Information on the solicitation process and the qualifications of the selected service provider is contained in Chapter X.

#### ***F. Staffing***

Staffing requirements for KRCD's performance of the above functions are approximately seventeen full time equivalent positions, once the phase-in is complete and the program is fully operational.<sup>2</sup> These staffing requirements are in addition to the services provided by the third party energy suppliers and contractors.

Table 4 below shows the staffing plan for KRCD's role as Power Services Provider at initial full-scale operational levels. Program staffing requirements during the pre-startup and phase-in periods are discussed in Chapter IV.

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<sup>2</sup> These staff levels and efforts do not include the activities associated with the regional base load power plant, which KRCD is currently developing.

**Table 4**  
**KRCD Staffing Plan for Power Services**  
**Provided to the San Joaquin Valley Power Authority**  
**Community Choice Aggregation Program**

<b>Position</b>	<b>Staff (Full Time Equivalents)</b>
Management	
Program Manager	1.0
Contract Analyst	1.0
Administrative Assistant	0.5
Finance and Rates	
Manager	1.0
Rates Analyst	1.0
Accounting/Billing Analyst	1.0
Sales and Marketing	
Manager	1.0
Account Representative	4.0
Communications Specialist	1.0
Administrative Assistant	1.0
Regulatory	
Manager	1.0
Regulatory Analyst	1.0
Resource Planning	
Planner	1.0
Information Technology	
IT Specialist	1.0
Human Resources	
HR Specialist	0.5
<b>Total Staffing</b>	<b>17.0</b>

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

#### IV. STARTUP PLAN AND FUNDING

This Chapter presents the Authority’s plans for the Start-up period, including the necessary staffing and capital outlays, which will commence once the CPUC certifies its receipt of this Implementation Plan. As described in the previous Chapter, the Authority will utilize a mix of KRCD staff and contractors in its CCA Program implementation. Table 5 illustrates the expectations for start-up, near-term (two to five years), and long-term anticipated staffing roles.

**Table 5**  
**Expectations for Staffing Roles**

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

##### **A. Staffing Requirements**

Staffing is a key component to the Start-up Plan. Staff will be added incrementally to match workloads involved in forming the new organization, managing contracts, and initiating customer outreach/marketing during the pre-operations period. Additional staff will be added during the Phase 1 customer enrollment period and following commencement of service. Additional sales and marketing staff will be added prior to

the notification and enrollment period for Phase 2 customers, many of which will have assigned customer account representatives. The organization should be nearly fully staffed by the time the Phase 2 customers are enrolled.

Table 6 is an estimate of the appropriate staff additions that KRCD will require for 2007 to implement and operate the CCA Program. Actual staff will be dependent upon several factors including final execution of the PSA, ability to recruit and hire qualified staff, and other internal KRCD requirements.

**Table 6  
Internal Staffing Estimates**

Staffing Plan (FTEs)	Pre-Startup					Execution of Agreements and Filing of Registration Plan			Enrollment 1 – Pilot Phase		Phase 1 Operations		Phase 2 Notification
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07		Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
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	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0
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
Rates Analyst	-	-	-	-	-	-	-	-	-	-	-	1.0	1.0
Accounting/Billing Analyst	-	-	-	-	-	-	-	-	-	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	-	-	-	-	-	-	-	-	-	-	2.0	4.0	4.0
Communications Specialist	-	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0
Administrative Assistant	-	-	-	-	-	-	-	-	-	-	-	1.0	1.0
Regulatory													
Manager	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Regulatory Analyst	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0
Resource Planning													
Planner	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Information Technology													
IT Specialist	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0
Human Resources													
HR Specialist	-	-	-	-	-	-	-	-	-	-	0.5	0.5	0.5
<b>Subtotal Staffing</b>	<b>2.5</b>	<b>2.5</b>	<b>2.5</b>	<b>2.5</b>	<b>2.5</b>	<b>2.5</b>	<b>4.5</b>	<b>4.5</b>	<b>6.5</b>	<b>9.5</b>	<b>13.0</b>	<b>17.0</b>	<b>17.0</b>

## ***B. 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 and the anticipated requirement is discussed below. The Finance Plan and the monthly balance sheets in Chapter VII provide a detailed overview of the capital requirements.

Staffing costs for calendar year 2007 are estimated to be approximately \$600,000. Actual costs may vary depending on the ability of KRCD to recruit qualified staff to fill the roles described above. Contractor costs for the same time period are estimated to be approximately \$1.0 million. These costs include: advertising, 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 KRCD will require as well as the distribution utility fees for initiating the CCA Program. Infrastructure costs are estimated to be approximately \$200,000 and the distribution utility fees are estimated to be approximately \$400,000.

Therefore, the total staffing, contractor and program initiation costs are expected to range from \$2.0 to \$3.0 million. These are costs that ultimately will be collected through CCA Program rates; however, most of these costs will be incurred prior to the Authority selling its first kWh of electricity. In addition, as discussed in Chapter VII (Financial Plan), it is anticipated that additional working capital will be required to purchase electricity for Program customers prior to revenue being collected from those customers.

Short-term financing instruments, such as a letter of credit or commercial paper (CP) will be used to cover these start-up costs and working capital requirements. The amount of CP required supporting the CCA Program through start-up and implementation of all four customer phases is estimated to be \$50 million, of which approximately \$10 million is to support start-up through Phase 2. The actual amount of CP required will be primarily dependent upon power purchase requirements.

## ***C. Startup Activities and Costs***

The initial startup funding estimate of \$2.0 to \$3.0 million is budgeted to fund the following activities and costs:

- Define and execute communications plan
  - Media campaign
  - Informational materials and customer notices
  - Customer call center
- Hire sales and marketing representatives
- 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.

### 1. 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 revenues from program operations commence. These costs have been characterized as startup costs for purposes of the financing plan.

**Table 7  
Estimated Start-up Costs**

Start-up Costs	CY 2007	Pre-Startup								Enrollment 1 - Pilot Phase		Cutover 1	Notification and Enrollment Period	
		Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08
Staffing		2.5	2.5	2.5	2.5	2.5	2.5	4.5	4.5	6.5	9.5	13	17	17
FTEs														
Cost	\$ 607,208	\$ 25,458	\$ 25,458	\$ 25,458	\$ 25,458	\$ 25,458	\$ 25,458	\$ 42,250	\$ 42,250	\$ 61,208	\$ 75,292	\$ 99,938	\$ 133,521	\$ 133,521
Infrastructure														
Cost	\$ 176,750	\$ 7,500	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 68,458	\$ 11,458	\$ 23,458	\$ 20,458	\$ 21,958	\$ 23,458	\$ 11,458
Contractor Costs														
Advertising	\$ 100,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 20,000	\$ 20,000	\$ 10,000	\$ 50,000	\$ 50,000
Consulting	\$ 500,000	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667	\$ 41,667
Legal	\$ 194,667	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,667	\$ 16,667	\$ 16,667	\$ 16,667	\$ 16,667
Data Management	\$ 184,708	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 16,792	\$ 16,792	\$ 25,188	\$ 125,938	\$ 125,938
Subtotal Contractor Costs	\$ 979,375	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 95,125	\$ 95,125	\$ 93,521	\$ 234,271	\$ 234,271
IOU Fees (Including Billing)														
Cost	\$ 369,292	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 96,000	\$ 96,000	\$ 4,780	\$ 4,128	\$ 3,995	\$ 21,798	\$ 142,591	\$ 126,668
Grand Total	\$ 2,132,625	\$ 90,625	\$ 83,125	\$ 83,125	\$ 83,125	\$ 83,125	\$ 179,125	\$ 264,375	\$ 116,155	\$ 183,920	\$ 194,870	\$ 237,215	\$ 533,841	\$ 505,918

### 2. Estimated Staffing Costs

The table 8 provides the estimated staffing budgets for the startup period, reflecting the staffing plan shown above. Staffing budgets include direct salaries and benefits loading.

**Table 8  
Estimated Staffing Costs**

Staffing Costs (\$/Month)	Pre-Startup								Enrollment 1 - Pilot Phase		Cutover 1	Notification and Enrollment Period	
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08
Management													
Manager	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000	\$ 13,000
Contract Analyst									\$ 7,042	\$ 7,042	\$ 7,042	\$ 7,042	\$ 7,042
Administrative Assistant	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708	\$ 2,708
Finance and Rates													
Manager	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 11,917	\$ 11,917	\$ 11,917	\$ 11,917	\$ 11,917
Rates Analyst	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,042	\$ 7,042
Accounting/Billing Analyst												\$ 7,042	\$ 7,042
Administrative Assistant	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Sales And Marketing													
Manager	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750
Account Representatives									\$ -	\$ -	\$ 14,083	\$ 28,167	\$ 28,167
Communications Specialist	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,042	\$ 7,042	\$ 7,042
Administrative Assistant	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,417	\$ 5,417
Regulatory													
Regulatory Manager	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750	\$ 9,750
Regulatory Analyst	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,042	\$ 7,042	\$ 7,042	\$ 7,042
Resource Planning													
Planner	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,042	\$ 7,042	\$ 7,042	\$ 7,042	\$ 7,042	\$ 7,042	\$ 7,042
Information Technology													
IT Specialist	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,042	\$ 7,042	\$ 7,042	\$ 7,042
Human Resources													
HR Specialist	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,521	\$ 3,521	\$ 3,521
<b>Subtotal Staffing</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 42,250</b>	<b>\$ 42,250</b>	<b>\$ 61,208</b>	<b>\$ 75,292</b>	<b>\$ 99,938</b>	<b>\$ 133,521</b>

**3. 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 in table 9 below.

**Table 9  
Estimated Infrastructure Costs**

Infrastructure Costs (\$/Month)	Pre-Startup								Enrollment 1 - Pilot Phase		Cutover 1	Notification and Enrollment Period	
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08
Computers	\$ 7,500	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,000	\$ -	\$ 12,000	\$ 9,000	\$ 10,500	\$ 12,000	\$ -
Furnishings	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 51,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Office Space	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,375	\$ 9,375	\$ 9,375	\$ 9,375	\$ 9,375	\$ 9,375	\$ 9,375
Utilities	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,083	\$ 2,083	\$ 2,083	\$ 2,083	\$ 2,083	\$ 2,083	\$ 2,083
<b>Subtotal Infrastructure</b>	<b>\$ 7,500</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 68,458</b>	<b>\$ 11,458</b>	<b>\$ 23,458</b>	<b>\$ 20,458</b>	<b>\$ 21,958</b>	<b>\$ 23,458</b>	<b>\$ 11,458</b>
<b>Total Costs</b>	<b>\$ 32,958</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 25,458</b>	<b>\$ 110,708</b>	<b>\$ 53,708</b>	<b>\$ 84,667</b>	<b>\$ 95,750</b>	<b>\$ 121,896</b>	<b>\$ 156,979</b>	<b>\$ 144,979</b>

**4. Utility Implementation and Transaction Charges**

The estimated costs payable to the distribution utilities for services related to the CCA Program start-up period include costs associated with initiating service with the Authority, 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 10**  
**Estimated Implementation and Transaction Units**

Utility Transaction Fees (Units/Month)	Pre-Startup								Enrollment 1 - Pilot Phase			Cutover 1	Notification and Enrollment Period	
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	
Utility Fees														
Opt-Out Notifications														
Per Account									3,198	3,198	3,198	313,802	313,802	
Per Event									2	2	2	2	2	
Post enrollment notification														
Per Account											3,198			
Service Initiation														
Per Hour						1,200	1,200							
Customer List														
Per Event								2			2			
Mass enrollment														
Per Account											3,198			
Per Event											2			
Opt-Out Fees														
Per Opt Out												15,690	9,414	
Customer Contact Fee														
Per Minute									192	48	32	18,876	4,707	
Billing Fee														
Per Account											3,198	3,198	3,198	

**Table 11**  
**Estimated Implementation and Transaction Costs**

Utility Transaction Fees (\$/Month)	Pre-Startup								Enrollment 1 - Pilot Phase			Cutover 1	Notification and Enrollment Period	
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	
Utility Fees														
Opt-Out Notifications														
Per Account	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,151	\$ 1,151	\$ 1,151	\$ 112,969	\$ 112,969	
Per Event	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,800	\$ 2,800	\$ 2,800	\$ 2,800	\$ 2,800	
Post enrollment notification	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Per Account	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,279	\$ -	\$ -	
Service Initiation	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Per Hour	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 96,000	\$ 96,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Customer List	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Per Event	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,780	\$ -	\$ -	\$ 4,780	\$ -	\$ -	
Mass enrollment	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Per Account	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,279	\$ -	\$ -	
Per Event	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 8,240	\$ -	\$ -	
Opt-Out Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Per Opt Out	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,217	\$ 4,330	
Customer Contact Fee	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Per Minute	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 177	\$ 44	\$ 29	\$ 17,366	\$ 4,330	
Billing Fee	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Per Account	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,239	\$ 2,239	\$ 2,239	
Subtotal	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 96,000	\$ 96,000	\$ 4,780	\$ 4,128	\$ 3,995	\$ 21,798	\$ 142,591	\$ 126,668	

**5. 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. Table 12 shows the estimated contractor costs during the startup period.

**Table 12**  
**Estimated Contractor Costs**

Contractor Costs (\$/Month)	Pre-Startup								Enrollment 1 - Pilot Phase			Cutover 1	Notification and Enrollment Period	
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	
Contractor Costs														
General advertising	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 20,000	\$ 20,000	\$ 10,000	\$ 50,000	\$ 50,000	
Legal	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 16,000	\$ 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	\$ 12,500	
Implementation Support	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	\$ 29,167	
Customer Enrollment	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 8,396	\$ 8,396	\$ 8,396	\$ 25,188	\$ 25,188	
Customer Care (Call Center)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 8,396	\$ 8,396	\$ 8,396	\$ 25,188	\$ 25,188	
Accounts Receivable and Verification	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 8,396	\$ 8,396	\$ 8,396	
Total Contractor Costs	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 57,667	\$ 95,125	\$ 95,125	\$ 93,521	\$ 234,271	\$ 234,271	

**D. Financing Plan**

The initial start-up funding will be provided by KRCD via a short-term financing, likely commercial paper. KRCD will recover the principal and interest costs associated with

the start-up funding via retail rates. It is anticipated that the start-up costs will be fully recovered within the first couple of years of the Program operations through retail rates.

1. Working Capital

Operating revenues from sales of electricity will be remitted to the Authority beginning on approximately day 47 of program operations, based the distribution utilities standard meter reading cycle of 30 days and their payment/collections cycle of 17 days. Either the electric supplier or KRCD will be responsible for providing the working capital needed to support electricity procurement, subject to the outcome of negotiations with the selected electric supplier. If it is the electricity supplier, 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 KRCD, KRCD will meet working capital requirements related to program management, which will be included in the CP program associated with start-up funding.

2. 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 Section VII below.

## **V. PROGRAM PHASE-IN**

The Authority will phase-in its CCA Program over the course of four stages:

1. Participant Accounts
2. Large Commercial and Industrial Accounts
3. Medium Commercial Accounts
4. 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 300,000 plus customer base. This approach also allows the Authority and its primary contractor KRCD to address all system requirements (billing, collections, payments) under a phase-in approach to minimize potential exposure to uncertainty and financial risk by “walking” prior to ultimately “running”.

### ***A. Phase 1 – Member Accounts***

Phase 1 of the Program is targeted to begin on November 1, 2007; or as soon as practical following CPUC certification of its receipt of this Implementation Plan; final approval of the Program by the Parties (via approval of Program Agreement No. 1); and completion of all necessary implementing agreements including those with suppliers, the investor-owned utilities, KRCD and potentially others.

Phase 1 will consist solely of the direct electric accounts of the Program Participants’ (Member City and County) loads. Under this approach it has been modeled that the opt-out rate for accounts (and load) for the cities and Kings County will be zero percent. This will result in approximately 3,200 accounts representing a load of 200 GWh annually.

### ***B. Phase 2 – Large Accounts***

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

Phase 2 of the Program is focused on large electric users; those accounts that typically have demands in excess of 500 kW, in addition to the customers already included in Phase 1. For modeling purposes it is assumed that 10 percent of these customers will opt-out of the CCA Program. This provides for an estimated incremental Phase 2 customer class of approximately 450, with an annual load of 1,000 GWh.

***C. Phase 3 – Medium Accounts***

Phase 3 of the Program is targeted to begin approximately three months after Phase 2; however, the Governing Board has the authority to adjust this starting date depending upon the performance of the Program under Phases 1 and 2. The intent is to ensure that the Program continues to be operating properly. The transition from Phase 2 to Phase 3 of the Program represents a significant increase in both the number of customer accounts and the energy requirements of the Program.

Phase 3 of the Program includes medium sized commercial accounts, in addition to the customers already included in Phases 1 and 2. For modeling purposes it is again assumed that 10 percent of these customers will opt-out of the CCA Program. This provides for an estimated incremental Phase 3 customer class of 3,750, with an annual load of 800 GWh.

***D. Phase 4 – All Accounts***

The final Phase (Phase 4) provides for all electric customers within the service territory of the Authority's Members to have the option of participating in the CCA Program. Again an opt-out rate of 10 percent of the 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 4 is 280,000 customers and 3,000 annual GWh.

The assumed start date for Phase 4 of the Program is six months after the commencement of Phase 3, again subject to the final review and approval of the Governing Board. This schedule provides for all eligible customers to be in the CCA Program by the end of 2008.

## VI. LOAD FORECAST AND RESOURCE PLAN

### A. Introduction

This chapter of the Implementation Plan describes the Authority's ten year resource plan, which strives to create a diversified portfolio of electricity supplies capable of meeting the electric demands of the Authority's retail customers, plus sufficient reliability reserves. As a Community Choice Aggregator, the Authority is responsible to arrange for the scheduling of sufficient electric supplies to meet the hour-by-hour demands of its customers. The Authority must also 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 will be responsible for ensuring that its resource mix contains sufficient production from renewable energy resources needed to comply with the statewide renewable portfolio standards.

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

- Reliability
- Stability
- Cost effectiveness
- Environmental responsibility

To meet these objectives and the applicable regulatory requirements, the Authority's resource plan includes a diverse mix of generation, power purchases, renewable energy and ultimately new energy efficiency programs. Similarly to how diversification benefits an investment portfolio by reducing risk and exposure to a particular market sector, 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 core of the Authority's resource mix is comprised of generation assets owned by KRCD, the Authority's power services provider, which will provide the bulk of the Authority's electricity long-term requirements on a cost-of-service basis. Locally-owned and managed generation assets form a foundation of efficient, low cost supply for the program. Fixed price contracts of varying lengths will supplement the KRCD generation and provide additional price certainty and rate stability for the Authority's customers. The Authority has developed a resource plan that integrates 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 intends to actively pursue, promote and ultimately administer a variety of customer energy efficiency programs that can cost-effectively displace supply-side resources.

The Authority's initial resource plan for the years 2007 through 2016 is summarized in table 13.

**Table 13  
Initial Resource Plan**

San Joaquin Valley Power Authority Energy Balance (GWh) 2007 to 2016										
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
<b>SJVPA Demand (GWh)</b>										
Retail Demand	-30	-2,058	-4,832	-4,953	-5,076	-5,203	-5,333	-5,467	-5,603	-5,744
Losses and UFE	-2	-165	-387	-396	-406	-416	-427	-437	-448	-459
Total Demand	-32	-2,222	-5,218	-5,349	-5,483	-5,620	-5,760	-5,904	-6,052	-6,203
<b>SJVPA Supply (GWh)</b>										
<u>Renewable Resources</u>										
Generation	0	0	0	0	0	0	0	0	0	0
Power Purchase Contracts	4	329	821	991	1,015	1,041	1,067	1,093	1,121	1,149
Total Renewable Resources	4	329	821	991	1,015	1,041	1,067	1,093	1,121	1,149
<u>Conventional Resources</u>										
Generation	0	0	0	0	2,759	2,759	2,759	2,759	2,929	2,929
Power Purchase Contracts	28	1,893	4,397	4,358	1,708	1,820	1,934	2,051	2,002	2,125
Total Conventional Resources	28	1,893	4,397	4,358	4,467	4,579	4,693	4,811	4,931	5,054
Total Supply	32	2,222	5,218	5,349	5,483	5,620	5,760	5,904	6,052	6,203

**B. Supply Requirements**

The Authority's resource plan begins with 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 or SCE during the customer enrollment and opt-out period. The Authority's phased roll-out plan and assumptions regarding customer participation rates are discussed below.

**C. Load Forecast**

**1. Roll-Out Schedule**

The Authority plans to begin serving its first customers in November 2007 and expects to have offered service to all eligible customers by the end of 2008. Eligible customers will be provided the opportunity to enroll in the program according to a four phased implementation schedule as defined below:

**Table 14  
Phase-in Schedule**

Phase	Start	Eligibility
Phase 1	November 2007	Municipal Accounts
Phase 2	February 2008	Large Commercial and Industrial Accounts
Phase 3	May 2008	Medium Commercial Accounts
Phase 4	November 2008	All Others

By the end of 2008, the program will have been offered to all electric customers within the jurisdictional boundaries of the Authority's Members.

## 2. Customer Participation Rates

Customers will be automatically enrolled in the Authority's electricity program unless they opt-out during the customer notification process conducted during the 60-day period prior to enrollment and continuing through the 60-day period following commencement of service. The Authority anticipates an overall customer participation rate of 100 percent during Phase 1, when service is being offered to the service accounts that are affiliated with the Authority's Members. Participation rates are expected to be 90 percent during Phases 2 through 4 based on experience with similar opt-out style municipal aggregation programs developed in other states; these have ranged from 5 percent in Massachusetts to 10 percent in Ohio. The participation rate is not expected to vary significantly among customer classes, in part due to the fact that the Authority expects to offer lower and more stable generation rates than PG&E and SCE for all participating customers and that focused marketing efforts will be directed at the commercial and industrial customers who may otherwise be more inclined to remain with known entities like PG&E and SCE. The assumed participation rates will be refined as the Authority's marketing and communications plan is executed.

## 3. 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 100 service accounts per day will be switched over during the first month of service. Enrollments planned for Phase 2 and 3 will be relatively few in number; however, during Phase 4, the Authority's customer account systems must be capable of processing customer enrollments of nearly 10,000 accounts per day. The number of accounts served by the Authority at the end of each phase is shown in the table 15.

**Table 15**  
**Estimated Retail Service Accounts**

**San Joaquin Valley Power Authority**  
**Retail Service Accounts**  
**Phase-In Period (End of Month)**

	<b>Nov-07</b>	<b>Feb-08</b>	<b>May-08</b>	<b>Nov-08</b>
<b>SJVPA Customers</b>				
Residential	-	-	-	248,819
Small Commercial	1,617	1,617	1,617	25,629
Medium Commercial	180	180	3,946	3,946
Large Commercial	105	510	510	510
Industrial	8	47	47	47
Street Lighting & Traffic	1,217	1,217	1,217	2,474
Ag & Pump.	71	71	71	4,195
<b>Total</b>	<b>3,198</b>	<b>3,642</b>	<b>7,409</b>	<b>285,620</b>
 Customer Additions	 3,198	 444	 3,767	 278,211

The forecast of service accounts (customers) served by the Authority for each of the next ten years is shown in the following table 16, which reflects an estimated annual account growth of 2.5 percent.

**Table 16**  
**10-Year Estimated Retail Service Accounts**

**San Joaquin Valley Power Authority**  
**Retail Service Accounts (End of Year)**  
**2007 to 2016**

	<b>2007</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>
<b>SJVPA Customers</b>										
Residential	-	248,819	252,551	256,339	260,184	264,087	268,048	272,069	276,150	280,292
Small Commercial	1,617	25,629	26,013	26,404	26,800	27,202	27,610	28,024	28,444	28,871
Medium Commercial	180	3,946	4,005	4,065	4,126	4,188	4,251	4,315	4,380	4,445
Large Commercial	105	510	518	526	533	541	550	558	566	575
Industrial	8	47	48	49	49	50	51	52	52	53
Street Lighting & Traffic	1,217	2,474	2,511	2,548	2,587	2,625	2,665	2,705	2,745	2,787
Ag & Pump.	71	4,195	4,258	4,322	4,386	4,452	4,519	4,587	4,655	4,725
<b>Total</b>	<b>3,198</b>	<b>285,620</b>	<b>289,904</b>	<b>294,252</b>	<b>298,666</b>	<b>303,146</b>	<b>307,693</b>	<b>312,309</b>	<b>316,993</b>	<b>321,748</b>

**4. 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 over 30 GWh in 2007 to over 2,000 GWh in 2008 and over 5,000 GWh at full roll-out by 2009. Annual energy requirements are shown below.

**Table 17**  
**Estimated Energy Requirements**

San Joaquin Valley Power Authority Energy Requirements (GWH) 2007 to 2016										
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
<b>SJVPA Demand (GWh)</b>										
Retail Demand	30	2,058	4,832	4,953	5,076	5,203	5,333	5,467	5,603	5,744
Losses and UFE	2	165	387	396	406	416	427	437	448	459
<b>Total Load Requirement</b>	<b>32</b>	<b>2,222</b>	<b>5,218</b>	<b>5,349</b>	<b>5,483</b>	<b>5,620</b>	<b>5,760</b>	<b>5,904</b>	<b>6,052</b>	<b>6,203</b>

**5. 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 Fresno area as defined by the CAISO. The Greater Fresno area is a region within California that the CAISO defines as being capacity deficient. In fact, a major component of the overall CCA Program is to add in-area generation to this region. 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 and SCE service area) local capacity requirements adopted by the CPUC based on the Authority’s forecasted peak load in each service area. The formula is as follows:

$$\text{Authority Local Capacity Requirement} = [\text{Authority Capacity Requirement} / \text{Total Distribution Utility Service Area Capacity Requirement}] * \text{Total Local Capacity Requirement in Distribution Utility’s Service Area.}$$

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 is approximately \$73 per kW-year.

The Authority's first resource adequacy filing could take place as early as October 2007, 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 2008 and 2009 are shown in the following table.

**Table 18  
Estimated Authority Resource Adequacy Requirements**

<b>San Joaquin Valley Power Authority Summer Peak Loads (MW) 2007 to 2009</b>				<b>San Joaquin Valley Power Authority Forward Capacity and Reserve Requirements (MW) 2007 to 2009</b>			
<b>Month</b>	<b>2007</b>	<b>2008</b>	<b>2009</b>	<b>Month</b>	<b>2007</b>	<b>2008</b>	<b>2009</b>
May	-	327	677	May	-	338	700
June	-	363	894	June	-	375	925
July	-	406	1,243	July	-	420	1,286
August	-	420	1,310	August	-	434	1,356
September	-	415	938	September	-	429	971

Although the Authority's load profile is normally summer peaking, actual annual peaks during 2008 will occur in November because of the significant load additions associated with Phase 4 planned for the fall in accordance with the Authority's phased roll-out plan. As a result, the year-ahead resource adequacy demonstration for 2008 will not encompass the annual peak of the Authority. Regulatory reporting requirements notwithstanding, the Authority's plan ensures sufficient reserves are procured to meet its peak load at all times. The Authority's annual capacity requirements are shown in table 19.

**Table 19  
Estimated Authority Capacity Requirements**

	<b>San Joaquin Valley Power Authority Capacity Requirements (MW) 2007 to 2016</b>									
	<b>2007</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>
<b>SJVPA Demand (MW)</b>										
Retail Demand	28	650	1,213	1,243	1,274	1,306	1,339	1,372	1,406	1,442
Losses and UFE	2	52	97	99	102	104	107	110	113	115
Total Net Peak Demand	31	702	1,310	1,343	1,376	1,410	1,446	1,482	1,519	1,557
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	5	105	196	201	206	212	217	222	228	234
Capacity Requirement Including Reserve	35	808	1,506	1,544	1,582	1,622	1,663	1,704	1,747	1,790

## 6. Renewable Portfolio Standards Energy Requirements

### *a) Basic RPS Requirements*

As a CCA, the Authority is required by law and ensuing CPUC regulations to procure a minimum percentage of its retail electricity sales from qualified renewable energy resources. Under the California 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 one 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 will incorporate any changes in these assumptions that result from the Commission's rulemaking process.

### *b) 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 one 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 years, and the "Incremental Procurement Target", which is at least one percent of the previous 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 APT without explanation, as long as the shortfall is made up within three years. Shortfalls greater than 25 percent of APT 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 five cents per kWh, capped at \$25 million per year.

*c) 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 2008, the expected second year of the program, the Authority must procure at least one percent of its 2007 retail sales from renewable resources, and in 2010, the Authority must meet the full 20 percent renewable standard (based on 2009 retail sales). The Authority's annual RPS requirements are shown in the table 20.

**Table 20  
 Estimated Authority RPS Requirements**

San Joaquin Valley Power Authority RPS Requirements (MWh) 2007 to 2016										
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Retail Sales	29,588	2,057,768	4,831,850	4,952,647	5,076,463	5,203,374	5,333,459	5,466,795	5,603,465	5,743,552
Baseline	-	-	296	20,874	966,370	990,529	1,015,293	1,040,675	1,066,692	1,093,359
Incremental Procurement Target	-	296	20,578	945,497	24,159	24,763	25,382	26,017	26,667	27,334
Annual Procurement Target	-	296	20,874	966,370	990,529	1,015,293	1,040,675	1,066,692	1,093,359	1,120,693
% of Current Year Retail Sales		0%	0%	20%	20%	20%	20%	20%	20%	20%

The Authority will target matching PG&E's renewable energy percentage from the first day of its operations, and it will therefore significantly exceed the minimum RPS requirements during 2007 - 2009 as shown below.

**Table 21  
 Authority RPS Targets**

San Joaquin Valley Power Authority RPS Requirements and Program Renewable Energy Targets (MWh) 2007 to 2016										
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Retail Sales (MWh)	29,588	2,057,768	4,831,850	4,952,647	5,076,463	5,203,374	5,333,459	5,466,795	5,603,465	5,743,552
Annual RPS Target (Minimum MWh)	-	296	20,874	966,370	990,529	1,015,293	1,040,675	1,066,692	1,093,359	1,120,693
Program Target (% of Retail Sales)	15%	16%	17%	20%	20%	20%	20%	20%	20%	20%
<b>Program Renewable Target (MWh)</b>	<b>4,438</b>	<b>329,243</b>	<b>821,415</b>	<b>990,529</b>	<b>1,015,293</b>	<b>1,040,675</b>	<b>1,066,692</b>	<b>1,093,359</b>	<b>1,120,693</b>	<b>1,148,710</b>
Surplus (MWh)	4,438	328,947	800,541	24,159	24,763	25,382	26,017	26,667	27,334	28,017
RPS MW (@ 90% C.F.)	-	0	3	123	126	129	132	135	139	142
Program Target MW (@ 90% C.F.)	1	42	104	126	129	132	135	139	142	146
Annual Increase (MWh)	4,438	324,805	492,172	169,115	24,763	25,382	26,017	26,667	27,334	28,017

#### *D. Resources*

The Authority will seek to maximize use of local, cost-based generation resources in its resource plan, supplemented as needed by power purchases from resources both inside and outside of the San Joaquin Valley. Through a Power Services Agreement to be executed with the KRCD, the Authority will secure output from generation resources that will be owned by KRCD and from purchased power that will be procured by KRCD. Pursuant to the Power Services Agreement, KRCD will provide full requirements electric service to 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.

The Authority's resource plan anticipates the construction by KRCD of a base-load generation resource in the San Joaquin Valley planned to be online by the end 2010. The plan calls for construction of a natural gas-fueled, combined cycle combustion turbine to serve the Authority's base-load (i.e., the minimum level of demand that is utilized all year long) requirements. Peaking and shoulder load requirements will generally be met with power purchase contracts for the balance of this planning horizon.

#### *E. Generation*

The Authority will purchase power at cost-based rates from KRCD under the terms of the PSA between the Authority and KRCD. Access to local generation will provide a stable, low cost source of power for the majority of the Authority's annual load requirements, and will minimize exposure to prices on the volatile wholesale electric market.

KRCD is currently in the process of developing a nominal 500 megawatt (MW) base-load power plant within its service territory near the city of Parlier, with the majority of the plant's expected output expected to be used to supply the CCA Program. KRCD targets commercial operation of this power plant in late 2010. Once the plant is operational, it will serve as an integral part of the overall Authority's CCA Program. KRCD also owns the Malaga Peaking Power Plant (Malaga), a 97 MW peaking resource located just south of Fresno, California. Malaga is under a 10-year power purchase agreement with the California Department of Water Resources through 2015. Upon completion of that agreement, Malaga will also be utilized to meet the portfolio requirements of the Authority's customers.

The base-load resource is planned to be constructed within an area currently designated by the CAISO as a locally generation deficient area. Because it is planned to be located in a resource-constrained area, the local generation resource will help to mitigate congestion on the transmission system. Under the new market rules and congestion management protocols expected to be in place by 2010, it is likely that additional benefits will be realized from congestion revenues derived from the CAISO markets.

Any such revenues would further reduce the Authority's costs of providing service to its customers.

The resource will be among the most efficient operating in California and will meet stringent environmental standards, including the requirement that there be no net increase in air emissions resulting from its operation. Besides being highly efficient in its operations, the resource will have low annual capital costs due to the fact that its owner (KRCD) is a public agency that requires no profit or investment return and can finance the resource using tax-exempt debt. It will be located in a relatively low-cost, non-urban area, which should lower construction and ownership costs. The combination of these factors is expected to make the plant among the lowest cost of any new resource in the State.

Finally, KRCD also owns and operates the Pine Flat Hydro Electric Power Plant at the base of Pine Flat Dam. This 165 MW nameplate hydro electric facility is under a long-term agreement with the California Department of Water Resource (through 2034). No modeling of the potential benefits of Pine Flat into the Authority's resources portfolio has been undertaken at this time. However, it is a long-term resource that would bring significant value to the overall Program.

#### ***F. Purchased Power***

Power purchased from utilities, power marketers, public agencies, and/or generators will be the exclusive source of supply from 2007 to 2010 and will be a supplemental source of supply once the KRCD generation begins producing electricity in 2010-2011. The Authority will obtain all of its electricity from KRCD pursuant to the Power Services Agreement, and KRCD will procure a mix of power purchase contracts 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 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:

<b>Time Horizon</b>	<b>Length</b>
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 contract with its selected electric supplier:

### **Price Hedging Guidelines**

<b>Time Horizon</b>	<b>Percentage of Portfolio</b>
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.

#### ***G. Renewable Resources***

To meet the RPS standard, the Authority will secure power purchase contracts for qualified renewable energy resources, quickly ramping up to nearly a million MWh (approximately 125 MW) by 2011. To qualify as eligible for California's RPS, a generation facility must use one or more of the following renewable resources or fuels:

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

Studies sponsored by the CEC show over 7,000 MW of eligible renewable resources can be economically developed statewide by 2010.<sup>3</sup> The vast majority of this resource potential 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.

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 renewable energy to meet the Authority’s resource planning goals. 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. Considering transmission constraints and current transmission expansion plans of the investor-owned utilities, there are an estimated 14 million MWh per year of newly developable renewable resources available by 2010 as shown in table 22.

**Table 22**  
**Resources Identified for Potential CCA Development by 2010, Considering Existing and Planned Network Transmission System Capacity (MWh)**

<b>Resource Type</b>	<b>PG&amp;E Area</b>	<b>SCE Area</b>	<b>SDG&amp;E Area<sup>4</sup></b>
Geothermal	1,576,800	0	5,085,180
Wind	525,236	4,780,800	394,200
Biomass	525,000	1,094,562	156,366
<b>Total</b>	<b>2,627,036</b>	<b>5,875,362</b>	<b>5,635,746</b>
<i>Source: Community Choice Aggregation Demonstration Project; Draft Renewable Resource Development Roadmap; Navigant Consulting, Inc, February 2006.</i>			

Transmission capacity for energy imports from outside the host utility service area is available during certain times of the year but is not sufficient to ensure delivery of electricity to loads during all times. Electricity transmitted from points outside of the

<sup>3</sup> *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.

<sup>4</sup> 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.

region is also 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).<sup>5</sup> Ideally, the energy source would be located within the region, near the load center. The next best alternative would be for the resource to be located within or deliverable to the PG&E service territory. KRCD and the Authority are closely monitoring the proposed development, by PG&E, of the Midway-Gregg 500 kV transmission facilities as this would provide a means to potentially import renewable resources from Southern California into the Greater Fresno area.

For planning purposes, the Authority anticipates procurement from the following types of renewable resources:

*Near Term*

- Existing Qualifying Facilities with expiring contracts
- Expansion and re-powering of wind resources in Alameda County
- Geothermal in Lake and Sonoma Counties
- Local biomass projects
- Market wind purchases

*Longer Term*

- Local development of biomass and solar projects
- Wind imports from the Tehachapi Area
- Wind imports from the Pacific Northwest
- Wind resources in Solano County
- Geothermal imports from Nevada
- Geothermal imports from the Imperial Valley
- Solar CSP imports from Southern California (Riverside and San Bernardino counties)

The purpose of identifying likely resource areas is not to pre-judge the outcome of future renewable procurement efforts but rather to ascertain whether the Authority's renewable energy goals are realistically attainable based on the best information currently available.

Initially, the electric supplier selected for the Program will be responsible for meeting the RPS requirements under a full requirements electricity agreement. In the longer term, KRCD may request proposals directly from renewable developers to meet its RPS requirements, and responses to the solicitations would determine the specific resource

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<sup>5</sup> 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.

types and locations that will be utilized. Although this resource plan identifies likely resource types and locations, it is not possible to predict what projects might be proposed in response to KRCD's solicitations for renewable energy. Offers can be considered from renewable energy developers located virtually anywhere in the Western Interconnection as long as the electricity is deliverable to the CAISO control area, as required to meet the Commission's RPS rules. 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.

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 KRCD and 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 available resources for their own portfolio needs. Over the longer term, the transmission expansion plans of the utilities will provide additional resource options for the Authority.

#### *H. 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, AB 117 permits CCAs to apply to administer cost-effective energy efficiency programs. All electric utilities in the state include energy efficiency programs in their resource portfolios and annual budgets for California's distribution utilities are approximately \$700 million. Energy efficiency programs provide a least cost resource and enhance customer service.

This section addresses the Authority's consideration and treatment of energy efficiency as a component of an integrated resource plan. The Authority does not have plans in the immediate term to offer additional energy efficiency services beyond those already administered by the distribution utilities, and the Authority's customer load and resource forecast reflects current saturation levels of energy efficiency programs administered by the distribution utilities, for which CCA customers will continue to be eligible. However, the Authority believes additional opportunities for significant cost effective energy efficiency programs within the region exist, as described below, and the

Authority intends to fully explore its opportunities for offering expanded energy efficiency programs to participating customers.

### 1. Applicable Energy Efficiency Policy

The CPUC and State energy policy, as expressed in the Energy Action Plan and reaffirmed in D 04-12-048, is to make energy efficiency the highest priority procurement resource. As such, cost-effective energy efficiency should be first in the “loading order” of resources used to meet customers’ energy service needs.<sup>6</sup> 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.<sup>7</sup>

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 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.<sup>8</sup>

### 2. The Energy Action Plan

Following the biggest electricity and natural gas crisis in its history, California recognized that the State’s economic prosperity and quality of life are increasingly reliant upon dependable, high quality, and reasonably priced energy. In April 2003, the state’s principal energy agencies joined to create the Energy Action Plan with the following goal:

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<sup>6</sup> CPUC Rulemaking R.01-08-028, ATTACHMENT 3 ENERGY EFFICIENCY POLICY MANUAL FOR POST-2005 PROGRAMS, Page 2, Rule II.1

<sup>7</sup> Ibid., Page 3, Rule II.3

<sup>8</sup> 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.)

*Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies, including prudent reserves, are achieved and provide through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers.*

To ensure such energy supplies are achieved, the state requires significant development of its energy infrastructures including increased capacity in natural gas transport pipelines and storage facilities, increased and updated electric generation facilities and expansion of its electric transmission system. None of these will be achieved in the near term and energy efficiency, having just proven itself viable in the summer of 2001, came to the forefront as the most expedient and least cost energy resource alternative. The Energy Action Plan identified six actions of critical importance to be undertaken immediately in a sequential loading order:

1. Optimize Energy Conservation and Resource Efficiency
2. Accelerate the State's Goal for Renewable Generation
3. Ensure Reliable, Affordable Electricity Generation
4. Update and Expand the Electricity Transmission and Distribution Infrastructure
5. Promote Customer and Utility Owned Distributed Generation
6. Ensure Reliable Supply of Reasonably Priced Natural Gas

### 3. 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 the investor-owned utilities energy efficiency programs.

**Table 23**  
**Pacific Gas & Electric Energy Efficiency Programs 2006 - 2008**

<u>Program Type</u>	<u>Pacific Gas &amp; Electric Programs</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>Total</u>
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 46.4%	\$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

**4. Energy Efficiency in the Authority**

Given PG&E's combined authorized energy efficiency program budgets<sup>9</sup> and its annual projected energy delivered to retail customers<sup>10</sup>, customers on average will pay \$0.0026 per kWh to support the programs. This amount applied to retail energy projected for the Authority in 2008 yields an annual program/surcharge burden of \$13.9 million. Analysis that follows addresses the technical and economic potential for energy efficiency within the Authority's service territory and weighs the cost of implementing programs capable of achieving a program specific energy efficiency forecasts prepared according to the rules described above.

The following table shows energy efficiency potential for each type of energy efficiency initiative:<sup>11</sup>

<sup>9</sup> CPUC Decision D.05-09-043 and PG&E Advice Letter filing A.05-06-004

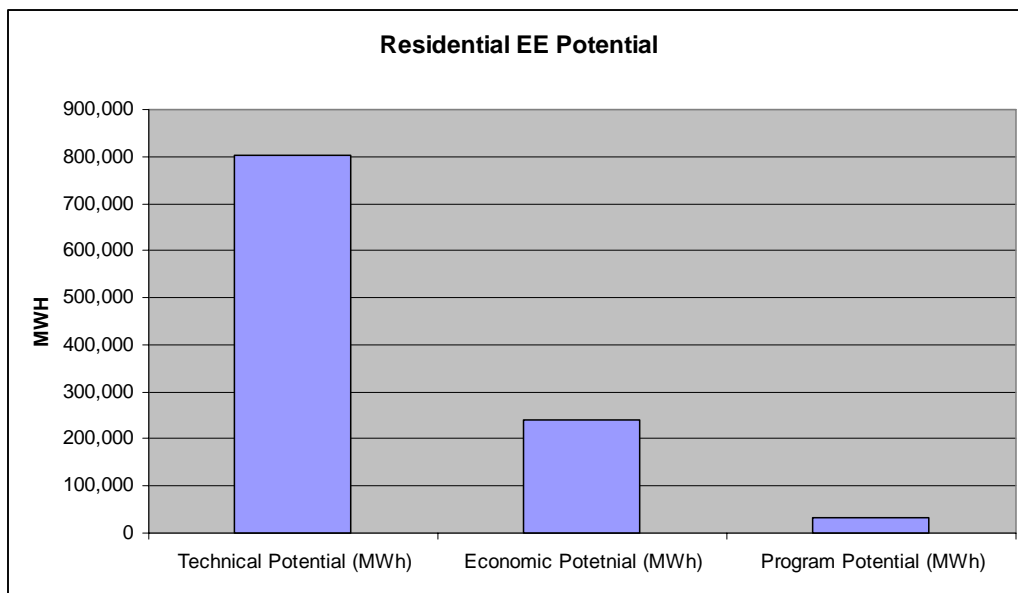
<sup>10</sup> California Energy Commission Report CEC-100-03-002

<sup>11</sup> California Energy Efficiency Potential Study, CALMAC Study ID: PGE0211.01, May 24, 2006

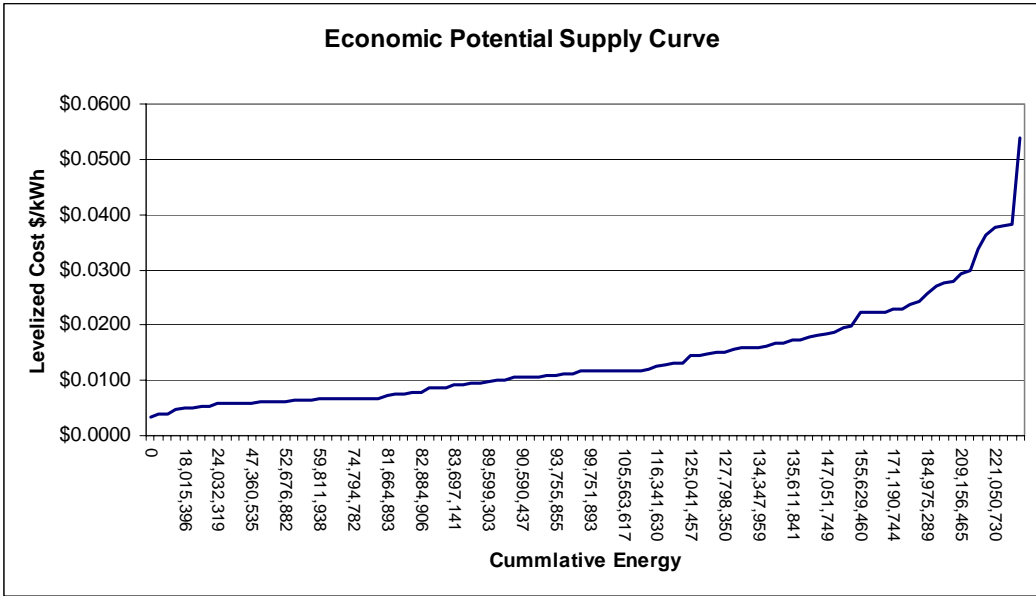
**Table 24**  
**Energy Efficiency Market Potential**

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

The retrofit of existing buildings represents 85 percent of the total forecast energy efficiency market potential. Studies show that the residential customer sector presents the largest untapped efficiency gains. The following chart shows the magnitude of technical, economic and program or market potential for residential energy efficiency within the Authority Member jurisdictions:



The next chart shows the resource supply curve associated with implementing energy efficiency measures as a supply-side alternative for the Authority:



As can be clearly identified above, a significant amount of demand-side energy resources can be obtained for inclusion in the Authority’s energy resource portfolio. The following measures describe the kinds of programmatic energy efficiency offerings shown to be needed within the Authority boundaries, shown in descending order by magnitude of energy savings (kWh):

Measure	2006 Potential	
CFL	9,706,333	31.1%
HVAC Testing & Repair	3,098,733	9.9%
HVAC TXV	2,734,011	8.7%
Whole House Fans	2,595,890	8.3%
Ceiling Insulation	2,315,803	7.4%
Window Film	2,100,633	6.7%
Attic Venting	1,625,460	5.2%
Duct Repair	1,404,055	4.5%
Programmable Thermostats	922,893	3.0%
Wall Insulation	756,605	2.4%
Heat Pump Water Heaters	671,401	2.1%
Water Heater Blanket	646,127	2.1%
Double Pane Windows	564,449	1.8%
Duct Insulation	521,845	1.7%
Evaporative Coolers	429,410	1.4%
LF Showerheads	283,924	0.9%
Programmable Thermostats	262,450	0.8%
HE Pool Pump & Motor	184,002	0.6%
Faucet Aerators	176,589	0.6%
Pipe Wrap	150,402	0.5%
HE Clothes Washing Machines	105,895	0.3%
	<b>31,256,912</b>	

Additional analysis will need to address commercial and industrial customer sector needs in similar detail. However, based on the proportions of efficiency potential

available, retrofit programs for the residential, commercial and industrial sectors are estimated to yield approximately 60 million kWh of savings for an annual program budget of approximately \$8.5 million. This estimate is based on current levels of incentives, program administration and marketing expenditures. Costs to administer such programs will vary by program type; however, program administration and marketing expense of approximately 25 percent, or \$2.1 million, is typical.

A near-term objective of the Authority is to develop a specific energy efficiency program that would seek to not only obtain these energy savings, but also seek requisite program funding from the CPUC to administer the energy efficiency program. Additional details of the Authority's energy efficiency plan will be developed once the CCA Program has successfully begun operations.

## VII. FINANCIAL PLAN

This Chapter examines both the cash flow analysis of the implementation period of the CCA Program as well as a discussion of the anticipated financing required for the overall CCA Program by KRCD.

### A. *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 November 2007 and continues through December 2010. 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 and SCE’s service territories. The Cash Flow Analysis assumes the Phase-In schedule for the Authority’s CCA Program as illustrated in the following table.

**Table 25**  
**San Joaquin Valley Power Authority**  
**Proposed Schedule for CCA Program Implementation**

<b>Phase</b>	<b>Customers</b>	<b>Date</b>
I	Member-owned facilities	November 2007
II	Large Commercial & Industrial Accounts	February 2008
III	Medium Commercial Accounts	May 2008
IV	Full Implementation	November 2008

#### 1. Cost of CCA Program Operations

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

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

➤ Franchise Fees

A key element of the Cash Flow Analysis is the assumption that electricity will be procured under a power purchase arrangement until the proposed base load power plant would be installed and operational. After that time, supply cost reductions are expected as the KRCD base load resource displaces power purchases. The focus of this Cash Flow Analysis is during the implementation period when opportunities for supply cost savings are more limited.

2. Revenues from CCA Program Operations

The Cash Flow Analysis also provides estimates for revenues generated from CCA operations or from electricity sales to customers. In determining the level of revenues, the Cash Flow Analysis assumes the Customer Phase-In schedule noted above, and assumes that the Authority's CCA Program provides a discount of five (5) percent from the existing distribution utility forecasted generation rate for each customer class. Based on this assumed discount, table 26 provides comparison of the projected blended distribution utility rate and the Authority's blended electric rate over the CCA Program Implementation period.

**Table 26**  
**Comparison of Electric Rates – Authority versus Distribution Utility**

CATEGORY	2007	2008	2009	2010
Authority's Blended Electric Rate (\$/MWh)	\$65.14	\$85.50	\$83.90	\$85.58
IOU Blended Electric Rate (\$/MWh)	\$68.57	\$90.29	\$87.09	\$90.24
Variance (\$/MWh)	\$3.43	\$4.79	\$3.19	\$4.66
Variance (%)	5.0%	5.3%	3.7%	5.2%

3. 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.

In terms of reviewing the results of the cash flow analysis, it is important to note that for a feasibility standpoint, the CCA program is viable, meaning that the CCA program is feasible while providing cost savings to customers when compared to the costs for

electricity those same customers pay under the distribution utility regime. The feasibility of the CCA program during the implementation period is summarized further below.

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 working capital based on the Phase-In of customers as described above is approximately \$50 million.

***B. 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 Program Implementation Feasibility Analysis (Feasibility Analysis) is that the Feasibility Analysis does not include a lag associated with payment streams. In essence, costs and revenues are reflected in the month in which service is provided. All other items, such as costs associated with CCA Program Operations and rates charged to customers remain the same.

The results of the feasibility analysis are shown below in table 27. Over the entire implementation period, and while providing a five percent electricity savings (estimated at over \$48 million) to customers, the Analysis demonstrates that the Program will generate an estimated positive cash flow of approximately \$27 million. This amount is subject to change depending upon final terms and conditions of the third-party power purchase agreement, and would potentially form the basis for a rate-stabilization or reserve fund. It may also be utilized for the development and implementation of renewable energy projects and/or energy efficiency programs.

**Table 27**  
**Summary of CCA Program Implementation**  
**(January 2007 through December 2010)**

CATEGORY	2007	2008	2009	2010	TOTAL
<b>I. REVENUES FROM OPERATIONS (\$):</b>					
<b>(A) ELECTRICITY SALES:</b>					
RESIDENTIAL	\$0	\$22,521,688	\$166,645,386	\$174,227,751	\$363,394,826
GENERAL SERVICE (A-1)	\$68,537	\$4,278,147	\$33,655,658	\$35,186,990	\$73,189,332
SMALL TIME-OF-USE (A-6)	\$482,750	\$6,704,385	\$17,670,706	\$18,474,723	\$43,332,563
ALTERN. RATE FOR MEDIUM USE (A-10)	\$328,720	\$56,072,888	\$75,607,475	\$79,047,615	\$211,056,698
500 - 900kW DEMAND (E-19)	\$442,849	\$41,644,717	\$46,000,722	\$48,093,755	\$136,182,042
1000 + kW DEMAND (E-20)	\$261,933	\$39,517,710	\$43,985,268	\$45,986,597	\$129,751,508
STREET LIGHTING & TRAFFIC CONTROL	\$307,720	\$1,987,118	\$2,556,581	\$2,672,905	\$7,524,323
AGRICULTURAL PUMPING	\$34,797	\$3,212,928	\$19,272,271	\$20,149,160	\$42,669,156
<b>TOTAL REVENUES</b>	<b>\$1,927,305</b>	<b>\$175,939,580</b>	<b>\$405,394,066</b>	<b>\$423,839,496</b>	<b>\$1,007,100,447</b>
<b>II. COST OF OPERATIONS (\$):</b>					
<b>(A) ADMINISTRATIVE &amp; GENERAL (A&amp;G):</b>					
STAFFING	\$607,208	\$1,664,000	\$1,719,250	\$1,747,446	\$5,737,904
INFRASTRUCTURE	\$176,750	\$142,000	\$137,500	\$139,755	\$596,005
CONTRACTOR COSTS	\$979,375	\$1,893,917	\$2,512,000	\$2,553,197	\$7,938,488
IOU FEES (INCLUDING BILLING)	\$369,292	\$1,097,444	\$2,399,204	\$2,438,551	\$6,304,491
<b>SUBTOTAL - A&amp;G</b>	<b>\$2,132,625</b>	<b>\$4,797,361</b>	<b>\$6,767,954</b>	<b>\$6,878,948</b>	<b>\$20,576,888</b>
<b>(B) CCA PROGRAM OPERATIONS:</b>					
ELECTRICITY PROCUREMENT	\$2,129,824	\$150,695,669	\$359,907,901	\$372,594,655	\$885,328,049
ANCILLARY SERVICES PROCUREMENT	\$0	\$0	\$0	\$0	\$0
GRID MANAGEMENT CHARGES	\$0	\$0	\$0	\$0	\$0
EXIT FEES	\$88,765	\$6,173,303	\$14,495,551	\$14,857,940	\$35,615,559
SCHEDULING COORDINATION	\$0	\$0	\$0	\$0	\$0
FRANCHISE FEES	\$19,712	\$1,443,318	\$3,385,194	\$3,616,918	\$8,465,142
BILLING	\$73,971	\$5,144,419	\$12,079,626	\$12,381,617	\$29,679,632
OTHER	\$0	\$0	\$0	\$0	\$0
<b>SUBTOTAL - CCA PROGRAM OPERATIONS</b>	<b>\$2,312,271</b>	<b>\$163,456,709</b>	<b>\$389,868,273</b>	<b>\$403,451,129</b>	<b>\$959,088,382</b>
<b>TOTAL COST OF OPERATION</b>	<b>\$4,444,896</b>	<b>\$168,254,070</b>	<b>\$396,636,227</b>	<b>\$410,330,077</b>	<b>\$979,665,270</b>
<b>CCA PROGRAM SURPLUS / (DEFICIT)</b>	<b>(\$2,517,591)</b>	<b>\$7,685,510</b>	<b>\$8,757,840</b>	<b>\$13,509,419</b>	<b>\$27,435,178</b>

As previously noted, the surplus shown in the above table provides for a five percent savings in electricity costs for customers compared to the costs under the distribution utility regime. This five percent reduction in electricity costs (generation component) represent over an estimated \$48 million for all customer classes over the implementation period. The following table provides an annual summary of the estimated savings for each customer class.

**Table 28**  
**Summary of CCA Program Savings by Customer Class**  
**(January 2007 through December 2010)**

CUSTOMER CLASS	2007	2008	2009	2010	TOTAL
RESIDENTIAL	\$0	\$1,276,004	\$6,394,157	\$9,503,110	\$17,173,271
GENERAL SERVICE (A-1)	\$3,607	\$241,750	\$1,235,867	\$1,909,957	\$3,391,182
SMALL TIME-OF-USE (A-6)	\$25,408	\$352,001	\$563,056	\$988,446	\$1,928,911
ALTERN. RATE FOR MEDIUM USE (A-10)	\$17,301	\$3,201,928	\$2,976,984	\$4,324,297	\$10,520,511
500 - 900kW DEMAND (E-19)	\$23,308	\$2,358,293	\$1,764,323	\$2,623,115	\$6,769,039
1000 + kW DEMAND (E-20)	\$13,786	\$2,074,802	\$1,401,537	\$2,460,404	\$5,950,530
STREET LIGHTING & TRAFFIC CONTROL	\$16,196	\$112,613	\$122,867	\$149,938	\$401,614
AGRICULTURAL PUMPING	\$1,831	\$232,690	\$965,637	\$1,136,873	\$2,337,031
<b>TOTAL</b>	<b>\$101,437</b>	<b>\$9,850,082</b>	<b>\$15,424,428</b>	<b>\$23,096,141</b>	<b>\$48,472,088</b>

### C. KRCD Financings

It is anticipated that at least three financings will be necessary, and possibly as many as six or more, 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 \$50 million
2. Base-load generation project financing – \$400+ million
3. Potential base load generation transmission upgrade – unknown at this time

#### 1. CCA Program Start-up and Working Capital

As discussed in Chapter IV the anticipated start-up and working capital requirements for the CCA Program through complete implementation are \$50 million. Depending upon the arrangements made between KRCD and the third party supplier the amount could potentially be half this estimate. Once the CCA Program is up and running, these costs would be recovered from the retail customers through retail rates. It is likely that in order to provide the targeted five percent discount to the retail customers, these costs may need to be carried until such time as the base-load power plant begins operations. Actual recovery of these costs will be dependent on third-party electricity purchase prices and decisions regarding rates, and negotiations between KRCD and the Governing Board regarding initial customer rates.

It is assumed that this financing will be via CP which would allow KRCD to draw cash as required and that the CP Program could be sized (increased/decreased) should it be needed in the future. This financing will occur in mid- 2007.

#### 2. Base Load Project Financing

This is the large project financing for the base-load power plant, currently estimated to be in the \$400+ million range. This financing would occur once the base-load project is completely sited and the CCA Program is up and running. The anticipated date for financial close for the base-load project is fall 2008. This financing will take out any

short-term financing for the base-load development costs, and will be in the range of a 20- to 30-year term.

The security for these bonds will be a hybrid of the revenue from sales to the retail customers of the Authority, including a termination fee (discussed in greater detail in Chapter IX) and the base-load generation project itself.

All financial pro formas prepared for this Implementation Plan assume that the debt service costs associated with the base-load 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 base-load project; however, an increase in the coverage requirements, or increase in the total costs of the base-load project (within reasonable levels) should not have a material impact on the overall CCA Program.

### 3. Base Load Transmission Network Upgrade

As discussed in greater detail in the Feasibility Report, the Greater Fresno Region suffers from limited energy infrastructure (power plants, electric transmission lines, and natural gas pipelines). KRCD has filed a system impact study (SIS) request with the California Independent System Operator (CAISO). This began a process that looks at what upgrades are required to PG&E's transmission system to interconnect and allow for the operation of the KRCD base-load generation project.

Based upon CAISO and PG&E studies related to Calpine's proposed San Joaquin Valley Energy Center, and preliminary studies undertaken by KRCD's consultant, the costs to upgrade PG&E's transmission system to accommodate the base-load project may be significant. However, in 2005, the FERC issued an Order regarding large generator interconnection policies. FERC rules now state that a developer that must pay for network upgrades to interconnect its project is authorized to be paid back by the transmission owner over a five-year period – with interest.

It is early in the process to know exactly how much the network transmission upgrades will cost, or the exact timing of the needed capital to pay for these upgrades; however, based upon FERC's Order and the CAISO's Tariff, these costs should (and KRCD will insist) that they be refunded with the FERC approved interest rate (prime rate). Because these monies would be paid directly to PG&E to upgrade its transmission system, and because the payback period is five years, this would be a separate financing from the base-load project financing.

For planning purposes it is anticipated that this financing would occur around the same time as the base-load project financing. The bonds would likely be for a period of seven to eight years, as the payback begins after the base-load project becomes operational.

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

<b>Proposed Financing</b>	<b>Estimated Amount</b>	<b>Estimated Term</b>	<b>Estimated Issuance</b>
1. Start-Up and Working Capital	\$50 million	No longer than 7 years	Mid-2007
2. Base Load Project Financing	\$400+ million	20-30 years	Late 2008
3. Network Transmission Upgrades	TBD	6 to 8 years	Late 2008/Early 2009

## VIII. RATESETTING

### *A. Introduction*

This section describes the initial policies for the Authority in setting its rates for electric aggregation services. These include policies regarding rate design, objectives, and 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 will be approved by the Governing Board and included in the initial customer opt-out notices.

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

### *B. Rate Policies*

The Governing Board will establish rates sufficient to recover all costs related to operation of the CCA Program, including any reserves that may be required as a condition of financing and other discretionary reserve funds that may be approved by the Governing Board. 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.

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

- Rate competitiveness
- Rate stability
- Equity among customers
- Customer understanding
- Revenue sufficiency

Each of these objectives is described below.

#### 1. Rate Competitiveness

The Authority's goal is to offer competitive rates for the electric services it provides to participating customers. The goal is for the Authority's rates to be set at a level between five and ten percent lower than the equivalent generation rates offered by the otherwise applicable electric utility (PG&E or SCE). The financial projections included in this Implementation Plan indicate that a savings potential as high as nine percent, on average, is an achievable long-term target due to the Authority's access to low cost generation sources.

## 2. Rate Stability

The Authority will offer stable rates by hedging its supply costs over multiple time horizons. Rate stability considerations may mean that rates at any point in time may offer somewhat greater or lesser savings than the general rate targets set for the program. Although the Authority's rates will be stabilized through execution of appropriate price hedging strategies, the distribution utility's rates can fluctuate significantly from year-to-year based on energy market conditions such as natural gas prices, the utility's hedging strategies, and hydro-electric conditions; and from rate impacts caused by periodic additions of generation to utility rate base.

## 3. Equity among Customer Classes

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

## 4. 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).

## 5. Revenue Sufficiency

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

### *C. Rate Design*

The Authority's rate designs will generally mirror the structure of PG&E's and SCE's generation rates so that similar rate benefits can be provided to the Authority's customers. For example, PG&E's and SCE'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 will 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 will generally

match the rate structures from the utilities' standard rates to avoid the possibility that customers would see significantly different bill impacts as a result of changes in rate structures when beginning service in 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.

#### ***D. Net Energy Metering***

Customers with on-site generation eligible for net metering from PG&E and SCE would be offered a net energy metering rate from the Authority. Net energy metering allows for customers with certain qualified solar or wind distributed generation to be billed on the basis of their net energy consumption. Recent CPUC 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. 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 utilities' net energy metering tariff to apply to the utilities' portion of the bill. To the extent that current CPUC regulations governing provision of net energy metering to CCA customers are unresolved, the Authority will work with PG&E, SCE and the CPUC to establish a net energy metering tariff that accomplishes this objective.

#### ***E. Rate Impacts***

Based on projected costs for 2007, the Authority's projected class average rates for its initial phase customers are shown in the table below.

**Table 29**  
**JVPA Estimated 2007 Program Rates**

<b>Customer Class</b>	<b>Program Rates – PG&amp;E Area (Cents Per kWh)</b>	<b>PG&amp;E Generation Rate (Cents Per kWh) *</b>
Residential	7.2	7.5
Small Commercial	7.5	7.9
Medium Commercial	8.2	8.6
Medium Industrial	7.6	8.0
Large Industrial	7.0	7.3
Agricultural	5.6	5.9
Street and Area Lighting	5.6	5.9
System	7.3	7.7
<b>Customer Class</b>	<b>Program Rates – SCE Area (Cents Per kWh)</b>	<b>SCE Generation Rate (Cents Per kWh) *</b>
Residential	9.2	9.7
Small Commercial	11.3	11.9
Medium Commercial	7.6	8.0
Medium Industrial	7.9	8.3
Large Industrial	5.7	6.0
Agricultural	7.8	8.2
Street and Area Lighting	6.5	6.9
System	8.8	9.3
<p>* The Cost Responsibility, which will be charged by the utilities to program customers, has been subtracted from the utilities' generation rates in order to make the rates comparable. The CPUC will determine the CRS for 2007 in December 2006 on a forecast basis. There will be no change in the charges for delivery services, for which the utilities will bill program customers at the same rates, terms, and conditions as applicable to utility bundled generation service customers. PG&amp;E and SCE rates are based on those contained in SCE Advice Letter 2080-E and PG&amp;E Advice Letter 2899-E-A, dated, December 28, 2006.</p>		

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 and SCE to the Authority. PG&E and SCE rates are shown for generation services only, net of the cost responsibility surcharge that the Authority's customers will pay directly to PG&E and SCE. Program rates are designed to provide participating customers with discounts of five percent, on average.

*F. Disclosure and Due Process in Setting Rates and Allocating Costs among Participants*

Initial program rates will be adopted by the Governing Board following the establishment of the first year's operating budget prior to initiating the customer notification process. Subsequently, the Authority will prepare an annual budget and corresponding customer rates and submit these as an application for a change in rates to the Governing Board. The rates must be approved at a public meeting of the Governing Board no sooner than sixty days following submission of the proposed rates, during which affected customers will be able to provide comment on the proposed rate changes.

The Authority will generally follow 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 counties 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 45 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.

## IX. CUSTOMER RIGHTS AND RESPONSIBILITIES

This chapter discusses customer rights, including the right to opt-out of the CCA Program, as well as obligations customers undertake upon agreement to enroll in the CCA Program. All customers that do not opt out within 60 days of enrollment in the Program (after having received four opt-out notices) will have agreed to become full status program participants and must adhere to the obligations set forth below, as may be modified and expanded by the Governing Board from time to time.

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

### 1. Customer Opt-Out Rights, Notices and Process

#### *a) Customer Notices*

A total of four notices will be provided to customers describing the program, informing them of their opt-out rights to remain with utility bundled generation service, and containing a simple mechanism for exercising their opt-out rights. The first notice will be mailed to customers approximately sixty to ninety days prior to the date of automatic enrollment. A second notice will be sent approximately thirty days later. Customers who do not affirmatively opt-out within this period shall be automatically enrolled in the Program.

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 will 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 Authority, but will otherwise not be subject to any penalty or transfer fee from the Authority.

The Authority will either use its own mailing service for opt-out notices or will take advantage of including the notices in the distribution utility's monthly bills. The Authority and KRCD will work with the distribution utility to determine the best means to provide the retail customers with this notice. As required by CPUC regulations, the Authority will use the utilities opt-out processing service. Customers may opt-out by notifying the distribution utility using the utility's automated telephone system or internet opt out processing services. All opt-out elections will be processed by the local distribution utility. Consistent with CPUC regulations, notices returned as undelivered mail will be treated as failure to opt-out and the customer will be automatically enrolled.

*b) Termination Fee*

Customers that are automatically enrolled in the program can elect to transfer back to the incumbent utility without penalty within the first two billing cycles of service. After this free opt-out period, customers may terminate their participation in the Program, at defined opt-out periods, subject to payment of a termination fee. The Authority will offer opt-out periods at regular three-year intervals. The initial post implementation opt-out period will occur in early 2011. The termination fee will apply to all program customers that elect to return to bundled utility service or elect to take “direct access” service from an energy services provider.

The termination fee will consist of two parts: an administrative fee set to recover the costs of processing the customer transfer and other administrative costs and a cost recovery charge (CRC) 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.

The administrative fee will vary by customer class as set forth in the table below.

**Table 30**  
**Administrative Fee for Service Termination**

<b>Customer Class</b>	<b>Fee</b>
Residential	\$25
Small Commercial	\$150
Medium Commercial	\$500
Large Commercial	\$2,500
Industrial	\$2,500
Street Lighting	\$75
Agricultural and Pumping	\$150

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 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 Section VII indicate that the Authority’s rates are expected to be below those charged by the local distribution utilities and that the Authority’s supply portfolio is projected to be competitive in the marketplace because of the financing advantages that KRCD enjoys. Under those conditions, most customers would not be expected to terminate their service with the Authority to return to the utilities. 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 lower rates than the local utilities.

The termination fee will be clearly disclosed in the four opt-out notices sent to customers during the sixty-day period before automatic enrollment and following commencement of service.

Customers electing to terminate service will be transferred to the new electric service provider 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 or SCE will also be liable for reentry fees imposed by the distribution utilities as set forth in the applicable utility CCA tariffs. Such customers will also be required to remain on bundled utility service for a period of three years, as described in the utility tariffs.

## 2. Customer Confidentiality

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

## 3. Responsibility for Payment

Pursuant to CPUC regulations, electricity service will not be shut off for failure to pay the Authority's bill. In most circumstances, customers will be returned to utility service for failure to pay bills in full and customer deposits will be withheld in the case of unpaid bills. Two late payment notices will 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 will be transferred to the utility on the next regular meter read date, unless alternative payment arrangements have been made. Consistent with the CCA tariffs, Rule 23, service will not 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.

Customers will be obligated to pay the Authority charges for service provided through the date of transfers including any applicable Termination Fees. The Authority must have an enforceable collection mechanism to support its credit and will attempt to negotiate collection arrangements with the distribution utilities that will satisfy the Authority's credit requirements. The Authority may petition the Commission to obtain shut-off rights for a customer non-payment of CCA charges, if a satisfactory collections agreement cannot be negotiated with the distribution utilities.

#### 4. 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 will cause the account service transfer from distribution utility to the Authority to be rejected, or the account will be transferred back to the local distribution utility. Customer deposits will be required based on the Program's credit policy to be adopted by the Governing Board.

## **X. PROCUREMENT PROCESS**

### ***A. Introduction***

This Chapter describes the Authority's initial procurement policies. The Authority has designated KRCD as its exclusive agent and power services provider. As such all contracting and procurement of services necessary to support the Program will be performed by KRCD.

By adopting this Implementation Plan, the Authority's Board of Directors approved the general procurement policies contained herein to be effective at Program initiation. The Board retains authority to modify Program policies from time to time at its discretion. Specific Program procurement policies will be included in the Power Services Agreement with KRCD.

### ***B. Procurement Methods***

KRCD anticipates entering into agreements for a variety of services needed to support program development, operation and management. KRCD will generally utilize competitive procurement methods for services but may also utilize direct procurement or sole source procurement, depending on the nature of the services to be procured. Direct procurement, or sole-source procurement, is the purchase of goods or services without competition when multiple sources of supply are available. Direct procurement is to be performed only in the case of emergency or when a competitive process would be an idle act.

KRCD will generally 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 basis at the discretion of KRCD. KRCD will report quarterly to the Governing Board a summary of the actions taken with respect to the delegated procurement authority.

### ***C. Key Contracts***

#### **1. Electric Supply Contract**

KRCD is in the process of negotiating a long-term (through 2015) electricity supply contract with a qualified provider. For the initial three years of program operations (11/1/2007 through 12/31/2010), the third party provider will supply electricity to customers under a full requirements contract between the provider and KRCD. Post-2010, KRCD's own resources, primarily the base-load project will be integrated into the resource portfolio. Under a full requirements contract, the supplier commits to serve the composite electrical loads of customers in the Program. The supplier is responsible for ensuring that a certified Scheduling Coordinator schedules the loads of all customers in the program and is also responsible for obtaining meter data from PG&E and SCE to

submit to the CAISO settlement process. The supplier is wholly responsible for the Program's 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 applicable resource adequacy and regulatory requirements imposed by the CPUC or FERC.

Risks related to customer opt-outs and changes in program loads during the term of the agreement are borne by the supplier. The supplier is allowed to charge different prices for sales to the various customer classes to help mitigate opt-out risks related to uncertainty in the load profile of the final customer mix.

The supplier must also specify the renewable content of the supply portfolio that will be used to supply the program for each year of the agreement term. Renewable energy disclosed must qualify to meet the California RPS and must be no less than 15 percent in 2007, 16 percent in 2008, 17 percent in 2009 and 20 percent in 2010.

## 2. Data Management Contract

A data manager will provide the retail customer services of billing and other customer account services (EDI with PG&E and SCE, billing, remittance processing, account management). Recognizing that some qualified wholesale energy suppliers do not typically conduct retail customer services whereas others (i.e., direct access providers) do, the data management contract is separate from the electric supply contract. A single contractor will perform all of the data management functions.<sup>12</sup>

The data manager is responsible for the following services:

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

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

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<sup>12</sup> The contractor performing account services may be the same entity as the contractor supplying electricity for the program.

3. Electric Supply Procurement Process

KRCD issued a request for bids and requested qualifications 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 reflects a highly qualified pool of suppliers for further negotiations, which will be completed prior to the Authority's registration as a CCA.

The timeline for the initial solicitation is as follows:

Action	Date
Request for bids issued	September 12, 2006
Pre-bidders conference	October 3, 2006
Proposals due	October 23, 2006
Selection of supplier(s)	December, 2006
Contracts negotiations and due diligence	December to March 2007
Contract Execution	May 2007
Commence Service	November 2007

On December 8, 2006 KRCD received final bids for third-party power supply from its two finalists. The bids were ranked based upon the following criteria:

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

Based upon these criteria, KRCD selected Citigroup Energy Inc. (CEI) to be its preferred energy partner and is currently working with CEI to develop an enabling agreement. CEI and its parent Citigroup, Inc. provide unparalleled financial strength and viability for the CCA Program. In addition, CEI has demonstrated a deep and growing understanding of the CCA Program as well as a commitment to work jointly with KRCD and the Authority to make the Program a success.

The experience of the CEI staff, their commitment to the CCA Program, and the financial strength of Citigroup provide the Authority and KRCD with an excellent partner.

Pursuant to their bid: the obligations of CEI are guaranteed by Citigroup Inc. (Citigroup), the world's largest financial institution. Citigroup is rated Aa1/AA-/AA+ and has total assets of \$1.5 trillion, annual net income of \$25 billion and a market value of \$266 billion.

While Citigroup has had a long and established history in the energy business dating back more than 28 years, CEI was formed in 2003 to provide a single point of contact for client driven solutions within the entire Citigroup organization. A key differentiator for CEI is their development of extensive physical market capabilities.

CEI has hired professionals with a deep, broad and diverse set of experiences within the energy markets. The CEI team has an average of 15 years of experience as well as prior work experience with 6 of the 10 largest energy-trading companies in the U.S. CEI is a Scheduling Coordinator for the CAISO.

Collectively, their professionals have served in excess of 8,000 MW (peak) of full requirement loads for terms of up to 10 years in markets such as AEP, Cinergy, Entergy, NEPOOL and PJM and managed in excess of 20,000 MW of generating assets.

Specifically, with respect to CEI's expertise in the western U.S. energy markets, their team has had day-to-day responsibility for (i) optimizing, dispatch and scheduling of 5,500 MW of generation assets in California and Nevada, (ii) procurement, transportation and scheduling in excess of 1.8 billion cubic feet ("BCF") of physical natural gas, (iii) acquisition and optimization of 400 million cubic feet ("MMCF") of long-term firm natural gas transport, and (iv) acquisition and optimization of 2.4 BCF of storage (including citygate storage).

## **XI. CONTINGENCY PLAN FOR PROGRAM TERMINATION**

### ***A. Introduction***

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

### ***B. Termination by Authority***

There is no planned program termination date. In the unanticipated event that the Governing Board decides to terminate the program and any applicable restrictions on such termination have been satisfied, notice will be provided to customers six months in advance that they will be transferred back to PG&E and SCE. A second notice will be provided during the final sixty days in advance of the transfer. The notice will 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 will be provided to PG&E, SCE and the CPUC before transferring customers, and the Authority will coordinate the customer transfer process to minimize impacts on customers and ensure no disruption in service. Once the customer notice period is complete, customers will be transferred *en masse* on the date of their regularly scheduled meter read date.

The Authority will maintain funds held in reserve to pay for potential transaction fees charged to the program for switching customers back to distribution utility service. Reserves will 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 community choice aggregator, except in the case of a customer returned for default or because its contract has expired. The Authority will self-insure against the risk of customer reentry fees.

### ***C. Termination by Members***

As set forth in the Joint Powers Agreement, Members may withdraw from the Authority upon six months written notice provided that such Members will be obligated to pay their pro-rata share of all encumbrances and indebtedness of the Authority as of the date of notice of termination on the Authority. As a consequence of a Member's withdrawal from the Authority, customers within the Member's jurisdiction will be returned to PG&E or SCE 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 the distribution utility tariffs, the Authority will execute a revised service agreement or specialized service agreement, as appropriate, with the distribution utility to coordinate the removal of the withdrawing Member from the CCA Program.

## **XII. APPENDIX A**

- A. AUTHORITY RESOLUTION 07-01*
- B. MEMBER ORDINANCES*

# **XIII. APPENDIX B**

*SAN JOAQUIN VALLEY POWER AUTHORITY – JOINT POWERS AGREEMENT*