COMMUNITY CHOICE AGGREGATION DRAFT IMPLEMENTATION PLAN

APPENDICES (A – M)

City and County of San Francisco

June 6, 2007

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Attachments

Appendix A:

SF CCA Draft Implementation Plan

CPUC Compliance Submission Document

COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PLAN

California Public Utilities Commission Compliance Filing

DRAFT – TO BE COMPLETED AND FILED WITH CPUC BY CCA PROGRAM DIRECTOR

City and County of San Francisco

June 6, 2007

1.0 Introduction

The City and County of San Francisco (CCSF) have elected to become a Community Choice Aggregator to provide electric power and a broad range of related benefits to the citizens and businesses located within its jurisdiction. The City and County of San Francisco are presenting this Community Choice Aggregation Implementation Plan in order to aggregate their customer's electric power loads in accordance with State and San Francisco laws that enable communities to form Community Choice Aggregation (CCA) Programs. This Implementation Plan provides a full description of the elements of the CCSF CCA Program as required by AB117.

In addition, San Francisco's CCA Program will comply with San Francisco Ordinance 86-04, which requires the City and County of San Francisco to implement a combined 360MW of renewable power generation, efficiency and conservation measures. Specifically, the Ordinance requires:

Load Reduction Through Electricity Load Management and Efficiency Measures	107 MW
In-City Solar Energy	31 MW
Small Scale Distributed Generation	72 MW
New Wind Energy	150 MW

The new renewables will increase power generation reliability by broadening the City's resource mix. The efficiency and conservation measures will reduce demand, which has the collateral benefit of further enhancing the reliability of the City's power supply and lessening the environmental impacts from conventional sources.

On May 11, 2004, the San Francisco Board of Supervisors unanimously adopted an "Ordinance establishing a Community Choice Aggregation Program in accordance with California Public Utilities Code Sections 218.3, 331.1, 366, 366.2, 381.1, 394, and 394.25, allowing San Francisco to aggregate the electrical load of electricity consumers within San Francisco, and to accelerate the introduction of renewable energy, conservation and energy efficiency into San Francisco's portfolio of energy resources." This Ordinance was signed by Mayor Gavin Newsom on May 27, 2004.

In order to exceed the green power rules binding PG&E to a 20% renewable requirement by 2010, as established by the state's Energy Action Plan and approved by the CPUC in 2003, San Francisco will employ its H Bond Authority to finance renewable power generation facilities. CCSF intends that these facilities will be built within the framework of a rate schedule commitment that is intended to be competitive with PG&E rates for generation plus the customer responsibility surcharge (CRS). In order to develop market-scale renewable energy, conservation and efficiency projects, the City and County will contract for the design, construction, operation, maintenance, and insurance of the 360MW infrastructure. The City's goal is to attain a 51% RPS by 2017.

The City and County will cooperate with Commission staff in clarifying any outstanding issues or concerns regarding its CCA program. The City and County will also be coordinating with Pacific Gas and Electric ("PG&E") and Commission staff throughout the CCA program implementation. PG&E has been presented with a full copy of this Implementation Plan on the same date that it was filed with the Commission.

- AB117 requires the "process and consequences of aggregation" to be detailed in the Implementation Plan. Furthermore, the list of the items below are specifically required to be included in a CCA Implementation Plan, in accordance with Public Utilities Code Section 366.2(c)(3). This Plan addresses each of these items.
- Organizational structure of the program, its operations, and its funding
- Ratesetting and other costs to participants
- Provisions for disclosure and due process in setting rates and allocating costs among participants
- Methods for entering and terminating agreements with other entities
- Rights and responsibilities of program participants, including consumer protection, credit issues, and shutoff procedures
- Program termination
- Description of third parties supplying electricity under the program

2.0 Process of Aggregation

Exhibit II-1 outlines the Community Choice Aggregation Implementation Steps required by the Public Utilities Code as follows.

Exhibit 2-1
CCA Implementation Steps
Under PUC 336.2

ITEM/CODE SECTION	ENTITY
Adopt rules authorizing community aggregation: 366.2(i)(3); procedures for IOUs to provide CCAs with information: (c)(9); terms and conditions for IOU services to CCAs and customers: (c)(9)	CPUC
Request and obtain utility load information: (c)(9)	CCA/IOU
Develop Implementation Plan (c)(3)	CCA
Adopt Implementation Plan through public process (after public notice)	CCA
File Implementation Plan at CPUC (c)(3) and register with CPUC: (c)(14)	CCA
Request additional information on Implementation Plan	CPUC
Respond to CPUC data requests	CCA
Notify local utility of Implementation Plan filing, within 10 days of the filing (c)(6)	CPUC
Certify receipt of Implementation Plan within 90 days (c)(7)	CPUC
Determine cost recovery charges CCA customers must pay (c)(7)	CPUC
Establish post-enrollment period reentry fees paid to IOUs: (c)(11)	CPUC
Designate earliest possible date for implementation of CCA Implementation Plan (c)(7)	CPUC
Select Energy Service Provider through competitive procurement process	CCA
Establish terms and rates for all transaction-based costs of notices, billing, metering, collections, customer communications or other services, to be recovered from aggregator or its customers: (c)(17)	CPUC
Order for IOUs to send out notices re: CCA Implementation Plan; establish fees CCP pays for notices: (c)(13)(B)	CCA requests CPUC issues order
Determine IOU meter costs (install, maintain, calibrate, read, supply data): (c)(18)	CPUC
Register with CPUC: (c)(14)	CCA
Send out 2 pre-enrollment notices to customers of CCA: (c)(13) (A)	CCA via IOU (utility bill)

ITEM/CODE SECTION	ENTITY
	pursuant to CPUC order or direct mailings
Notify IOU the community aggregation program will begin within 30 days: (c)(15)	CCA
Transfer accounts to CCA: (c)(16)	IOU
Recover transfer costs, as determined by CPUC, from CCA: (c)(17)	IOU
Begin CCA automatic enrollment	CCA
"No penalty" period for opting out ends, within 60 days or 2 billing cycles of the date of enrollment (c)(11)	
Send out 2 post-enrollment notices to customers: (c)(13)(A)	CCA via IOU (utility bill) and/or direct mailings
Submit report to Legislature certifying implementation of cost-recovery mechanisms: (i)(1) and (i)(2)	CPUC

Notes: *CCA = Community Choice Aggregator*
IP = Implementation Plan
IOU = Investor Owned Utility
CPUC = California Public Utilities Commission
All Code references are to Sec. 366.2

2.1 San Francisco's CCA Process History

In September, 1999, the Board of Supervisors unanimously adopted a Resolution by Supervisor Ammiano asking the California legislature to pass a Community Choice Aggregation law.

In November 2001 voters approved an amendment to the San Francisco Charter (San Francisco Charter Section 9.107.8), placed on the ballot by the Board of Supervisors ("H Bond Authority", Ammiano) creating an unlimited, generic revenue bond authority for the Board of Supervisors to issue bonds in order to finance or refinance the acquisition, construction, installation, equipping, improvement or rehabilitation of equipment or facilities for renewable energy and energy conservation, said issuance to be authorized by an ordinance of the Board. In particular, Mr. Ammiano announced plans to solicit an energy service provider to install 50 Megawatts of solar photovoltaic capacity within the jurisdictional boundaries of San Francisco.

In January, 2002 the San Francisco Public Utilities Commission held a World Solar Industry Workshop, which was followed by significant, incremental solar photovoltaic installations at public properties such as the Moscone Center. Subsequently, the Board of Supervisors has adopted an ordinance creating the Generation Solar program, offering residents and businesses assistance with solar photovoltaic purchasing. These programs have been undertaken as pilot projects, in order to prepare city departments for a major, billion dollar rollout of solar, wind, distributed generation, conservation and energy efficiency technologies at hundreds of locations throughout San Francisco's 49 square miles.

In March, 2002, San Francisco also adopted Resolution 158-02 directing the City to commit to a greenhouse gas pollution reduction of 20% below 1990 levels by the year 2012.

In December, 2002, San Francisco adopted an Electricity Resource Plan calling for the development of 107 Megawatts of load reduction through electricity load management and efficiency measures, 31 Megawatts of in-City solar energy, 72 Megawatts of small-scale distributed generation such as fuel cells in San Francisco and 150 Megawatts of new wind energy imports by 2012, as well as new natural gas powered generation needed to close over 420 megawatts of aging and polluting electric generating facilities at Hunters Point and Potrero power stations.

In September, 2003, the Local Agency Formation Commission ("LAFCO") accepted a report from R.W. Beck indicating that Community Choice Aggregation may be a feasible method of benefiting consumers and developing renewable energy resources, conservation programs and energy efficiency.

On May 21, 2004 the San Francisco Board of Supervisors unanimously adopted (ordinance 86-04, Ammiano, signed by Mayor Newsom on May 27, 2004), and it went into effect on June 27, 2004. The Energy Independence Ordinance is the governing document ordering preparation, and outlining the structure, of this Implementation Plan, and also ordering City agencies to present a draft Request for Proposals (RFP) for amendment and adoption by the Board of Supervisors.

Ordinance 86-04 also ordered City and County departments to request all appropriate billing and load data from PG&E, resulting in the delivery of some incomplete aggregate data.

On December 8, 2004, the Board of Supervisors unanimously approved a resolution (Ammiano, Resolution 757-04), creating a Community Choice Aggregation Citizen's Advisory Task Force "to advise the City on, 1) the goals and preparation of a CCA Implementation Plan, 2) the use of Proposition H Bonds to accelerate the use of renewable energy, conservation and energy efficiency in the CCA program, and 3) the requirements in the CCA bid solicitation process, and 4) the evaluation of bids. Furthermore, Resolution 757-04 affirmed that Ordinance 86-04 "called for the development of 107 Megawatts of load reduction through electricity load management and efficiency measures, 31 Megawatts of in-City solar energy, 72 Megawatts of small-scale distributed generation such as fuel cells in San Francisco and 150 megawatts of new wind energy capacity by 2012, as called for by the Electricity Resource Plan adopted by San Francisco in December 2002."

On February 5, 2005, the Board of Supervisors approved a Resolution (Mirkarimi, Resolution 131-05) urging the SFPUC to explore, based on findings of the Local Agency Formation Commission ("LAFCO") reports, implementation of Community Choice Aggregation on Treasure Island.

On March 29, **2005** the Board of Supervisors approved a Resolution (Mirkarimi, Resolution TBD) approving a "Protest Letter to the California Public Utilities Commission and the Procurement Review Committee Regarding Approval of Proposed Pacific Gas & Electric Power Purchase Agreements and Energy Efficiency Programs."

On May 13, **2005** the San Francisco Local Agency Formation Commission transmitted Local Power's Draft CCA Implementation Plan to the Board of Supervisors "With Recommendation".

Late Summer 2005, LAFCO adopted a resolution containing several recommendations concerning Local Power's Implementation Plan, based upon the SFPUC's Draft Implementation Plan.

2.2 Current Process: Implementation Plan Actions and Requests

In order for the Commission to facilitate the Board of Supervisors negotiation with ESPs pursuant to 366(a) of the Public Utilities Code, the City and County of San Francisco requests the Commission to provide, within 90 days of the receipt of this adopted Implementation Plan (which shall be delivered to the Commission the same business day it is adopted), the cost-recovery mechanism that must be paid by participating San Franciscans, pursuant to Section 366.2 (c)(7) of the Public Utilities Code.

Furthermore, the City and County expects that the Commission will request any additional information from the Board of Supervisors and certify receipt of this Implementation Plan, within 90 days of the passage of this resolution and the Implementation Plan it contains.

San Francisco also requests that the Commission provide the City and County with an earliest possible date to leave Pacific Gas & Electric procurement, in such manner that participating load transfer of customers shall occur 300 days from the date on which this resolution is approved by the Board of Supervisors.

The City and County requests the Commission to order PG&E to provide the City and County with all customer billing and load data, including all customer-specific data, time of use metering data, interval meter data, and substation data, including a detailed list of every data field contained in each of the databases. Accordingly, the City and County hereby agrees that it shall not disclose any confidential customer information to its ESP prior to the termination of the 120 day opt-out period, and shall require that all notices relevant to CCA programs inform customers that the utility may share customer information with the City and County, and that the City and County may not use the utility's information for any purpose other than to facilitate provision of energy services.

The City and County's chosen Electric Service Provider will be required to provide for participating customers' resource adequacy requirements as required by the CPUC. As Energy Efficiency is a core program in San Francisco, developing 107 Megawatts of conservation and energy efficiency funds within its ESP's power purchase agreement, the City and County declares its intent to seek to administer, starting in 2007 - 08, the energy efficiency Public Goods Charge funds paid by CCA customers. San Francisco asks the Commission to limit PG&E's energy efficiency programs so as to make a *pro rata* share these funds available, based on the participation of all residential, commercial, and eligible government electricity customers, for local administration to an energy service provider of the City's choosing starting 330 days after the adoption of this resolution, and the Implementation Plan it contains, by the Board of Supervisors.

According to the proposed schedule, the Board of Supervisors requests the Commission, pursuant to Public Utilities Code Section 366.2(c)(13)(B), to approve and order PG&E to insert the City and County's first CCA notification to San Francisco ratepayers 330 days from the approval of this Implementation Plan, adjusted to any delay in the Commission's timely response to this Implementation Plan, in its monthly electricity bill to San Francisco electricity ratepayers for the month following said Commission order following the request of San Francisco pursuant to Public Utilities Code Section 366.2(c)(13)(A).

San Francisco requests the Commission to order PG&E to send all four of the notifications required pursuant to subparagraph (A) in the electrical corporation's normally scheduled monthly billing process, and shall pay all reasonable incremental costs PG&E incurs related to the notification or notifications, provided that the electrical corporation, as required by Subsection A, shall fully cooperate with the City and County in determining the feasibility and costs associated with using PG&E's normally scheduled monthly billing process to provide one or more of the notifications required pursuant to subparagraph (A).

The City and County requests the Commission to designate a day no later than 330 days from the date this resolution is approved by the Board of Supervisors, pursuant to 366.2(c)(8), as the earliest possible date on which the City and County's CCA program may be implemented.

As Public Utilities Code 366.2(c)(16) requires PG&E to transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process, the City and County hereby notifies the Commission of the intended date of customer transfer as being 360 days from the adoption of this resolution and the Implementation Plan it contains.

According to this schedule, the Commission should order PG&E to insert San Francisco's second opt-out notification into the first monthly electric bills prior to transfer of customers.

Assuming Commission facilitation of the City and County's negotiations with ESPs according to the needs expressed herein, San Francisco declares its intent to transfer customers who did not opt-out of the City's chosen new service 60 days from the date of PG&E's first insertion of San Francisco's notification to customers, approximately 390 days from the approval of this resolution.

According to this schedule, the Commission should order PG&E to insert San Francisco's third opt-out notification into the monthly electric bill following the transfer of participating San Francisco electricity customers, 420 days from the date this resolution is approved.

According to this schedule, the Commission should order PG&E to insert San Francisco's fourth and final notification into its monthly electric bill following the third notification 450 days from the date this resolution, and the Implementation Plan it contains, is approved by the Board of Supervisors.

2.3 SF CCA Request for Proposal Process

The City and County of San Francisco (CCSF) declares its intent, upon receipt of an Exit Fee from the Commission within 90 days of the adoption of this resolution, or upon whatever date thereafter that the Commission submits its findings, to conduct a single competitive bidding process for the City and County's bundled energy service, conforming to the requirements of this Implementation Plan. The City's RFP, in accordance with Ordinance 86-04, is available to registered Electric Service Providers, by publishing the RFP notice in all major Bay Area Newspapers, and also in any state, national and international energy industry trade publication or publications, in order to secure the attention of energy industry sectors for each component of the services and resource portfolio required by the Ordinance and this Implementation Plan.

Accordingly, if the Commission takes these actions as needed by the City and County, then San Francisco intends to pass an ordinance awarding a contract to the City's chosen ESP within a reasonable period from the date this resolution is approved, pursuant to Public Utilities Code Section 366.2(c)(10(A)

Upon the day of termination of the opt-out period, the three-year rollout of the City's minimum 360 Megawatt solar, wind, conservation and efficiency facilities by the chosen ESP shall immediately commence, with the annual rollout schedule outlined in this Implementation Plan beginning on that day and ending on the day _____________ (INSERT DATE), as approved by the Board of Supervisors

However, if at the termination of the no-cost 120 day opt-out period required by AB117, ten percent or more of the eligible aggregate load has opted out, the 360 MW build requirement shall be proportionately downscaled across each portfolio component of the 360 MW by the actual opt-out amount, rounded to the nearest megawatt. For example, if 10% of the load opts-out, the revised three-year build requirement would be 324 MW of capacity (compared to 360 MW) distributed across the portfolio components as follows:

- 96 MW Energy Efficiency and Conservation in San Francisco
- 93 MW Distributed Generation in San Francisco including minimum 28 MW of Photovoltaics
- 135 MW wind

This downscaling shall be a one time event at the termination of the no cost opt out period only. Subsequent opt outs, if any, shall not change the MW build requirement. The RPS requirements, on the other hand, shall be adjusted on the basis of a percentage of kilowatt-hour consumption in any given year and not the megawatts of departing load.

3.0 Consequences of Aggregation

If the RFP is successful, San Francisco's CCA program will result in the departure of the vast majority of electricity ratepayers living or doing business in City and County jurisdictional boundaries who are now served by Pacific Gas and Electric. The City and County will not attempt to implement a phase-in of customers on a neighborhood-by-neighborhood basis nor on a customer class-basis, but shall offer its service to any and all PG&E commodity customers who do not elect to continue to be served by Pacific Gas and Electric procurement pursuant to 366.2(a)(2) of the Public Utilities Code.

New Unforecasted Load. In accordance with Resolution 131-05, San Francisco's CCA program may also result in adding the provision of service to any customers on Treasure Island who do not choose to opt out of the program, such that loads not forecasted by the Department of Water Resources nor by PG&E shall be included in this Plan, RFP and ESP contract. Thus, the City and County believes that the Commission's December 16, 2004 CCA proceeding decision (D.04-12-046 in R.03-10-003) to exempt the Inland Valley Development Authority (IVDA) from any DWR Contract obligations or bond charges should also apply to this component of the City and County's CCA load. The Commission reasoned:

> "Because DWR did not purchase any power on behalf of Norton AFB, ratepayers would not be harmed if IVDA is excluded from the DWR component of the CRS. IVDA's interpretation of AB 117 that the prohibition on cost-shifting should work in both directions is reasonable. Although we do not assume the statute requires this reciprocal treatment, we believe we can lawfully permit an exclusion or exception to the CRS requirements on that basis (D.04-12-046, p.39).

3.1 Departing PG&E customer load

The City and County has provided adequate notice for PG&E to avoid procurement on behalf of San Francisco ratepayers beyond 2006. San Francisco's Community Choice program will not impact any multi-year power contracts by Pacific Gas and Electric, which asserts that in its medium case, PG&E assumed that three percent of its current customers with load under 500 kW will begin to migrate to Community Choice Aggregation in 2006, and the rate of loss to this market will increase by one percent annually, reaching 10 percent in 2013, as recorded and referenced by the Commission in its December 16, 2004 procurement authorization (Decision 04-12-048, p.26). As this decision authorizes contracts now being negotiated and signed by PG&E in its first effort at multi-year power purchase agreements since AB1890 went into effect, PG&E's power contracts and advice letters to the CPUC and the Procurement Review Committee (PRC) should be viewed within the framework of PG&E's advance knowledge of, and planning for, its own assumptions regarding the magnitude of departing load as presented to the Commission. PG&E and the CPUC received San Francisco's Community Choice Implementation Ordinance on May 27, 2004 when it was signed by Mayor Gavin Newsom. The Ordinance ordered this Implementation Plan, and established the basic structure that this Plan must follow, in transaction structure, jurisdiction and in portfolio. With this Implementation Plan now filed, all other impacts of San Francisco's aggregation on electric utility procurement contracts are limited to its annual procurement process, Department of Water resources contracts, and DWR bond charges, as provided for in D.04-12-046.

As provided in Ordinance 86-04, San Francisco's aggregation will result in the installation of at least 150 Megawatts of new wind turbine capacity either within or outside the jurisdiction of San Francisco, 107 Megawatts of conservation and energy efficiency within its jurisdiction, and 104 Megawatts of distributed generation - including a minimum of 31 Megawatts of solar photovoltaic cells - within its jurisdiction. When combined, we believe these facilities will beneficially impact the entire San Francisco Peninsula's grid. Furthermore, this Implementation Plan establishes a Renewable Portfolio Standard for qualifying bidders of 51% for compliant resources by 2017. The City's RPS definition includes energy efficiency, conservation, customer and non-customer owned photovoltaics, and distributed renewable generation. The City's CCA Provider will also be required to comply with the State of California's Renewable Portfolio Standard law pursuant to state law and CPUC policy and resource definitions. See Exhibit 3-1 below: "San Francisco RPS."

Exhibit 3 -1
San Francisco RPS

1-2-3 - [SF Portfolio new.123]

EEFunds

San Francisco Model RPS Rollout

Contract yr. #	year	Baseline Consumption	Efficiency Capacity	Savings	pct.	CCA net consumption	New Build RPS Model	Cumulative CCA Renewables	Renewables Generation	RPS (hard)
		kwh	kw	kwh		kwh	Kw		Kwh	
1	2006	1,818,072,000	0	0	0.0%	1,818,072,000		0	0	0%
2	2007	3,690,686,160	36,000	63,072,000	1.7%	3,627,614,160	85,000	85,000	223,380,000	6%
3	2008	3,746,046,452	72,000	126,144,000	3.4%	3,619,902,452	85,000	170,000	446,760,000	12%
4	2009	3,802,237,149	107,000	187,464,000	4.9%	3,614,773,149	85,000	255,000	670,140,000	19%
5	2010	3,859,270,706	105,395	184,652,040	4.8%	3,674,618,666		255,000	670,140,000	18%
6	2011	3,917,159,767	103,814	181,882,259	4.6%	3,735,277,508	100,000	355,000	932,940,000	25%
7	2012	3,975,917,164	102,257	179,154,026	4.5%	3,796,763,138	100,000	455,000	1,195,740,000	31%
8	2013	4,035,555,921	100,723	176,466,715	4.4%	3,859,089,206	75,000	530,000	1,392,840,000	36%
9	2014	4,096,089,260	99,212	173,819,714	4.2%	3,922,269,545	80,000	610,000	1,603,080,000	41%
10	2015	4,157,530,599	97,724	171,212,419	4.1%	3,986,318,180	80,000	690,000	1,813,320,000	45%
11	2016	4,219,893,558	96,258	168,644,232	4.0%	4,051,249,325	80,000	770,000	2,023,560,000	50%
12	2017	4,283,191,961	94,814	166,114,569	3.9%	4,117,077,392		770,000	2,023,560,000	49%
13	2018	4,347,439,840	93,392	163,622,850	3.8%	4,183,816,990		770,000	2,023,560,000	48%
14	2019	4,412,651,438	91,991	161,168,508	3.7%	4,251,482,930		770,000	2,023,560,000	48%
15	2020	4,478,841,210	90,611	158,750,980	3.5%	4,320,090,230		770,000	2,023,560,000	47%
16	2021	4,546,023,828	89,252	156,369,715	3.4%	4,389,654,112		770,000	2,023,560,000	46%
17	2022	4,614,214,185	87,913	154,024,170	3.3%	4,460,190,016		770,000	2,023,560,000	45%
18	2023	4,683,427,398	86,595	151,713,807	3.2%	4,531,713,591		770,000	2,023,560,000	45%
19	2024	4,753,678,809	85,296	149,438,100	3.1%	4,604,240,709		770,000	2,023,560,000	44%
20	2025	4,824,983,991	84,016	147,196,528	3.1%	4,677,787,463		770,000	2,023,560,000	43%

Demand Calculations		
CCSF electric 2000	5,748,000,000	kwh
growth rate (est. avg.)	1.5%	
CCSF electric 2006 (e	6,285,111,881	kwh
SFPUC Load (est avg.	110	mw
SFPUC demand (est)	963,600,000	kwh
Net PG&E territory	4,784,400,000	kwh

Direct Access share	20%	
Direct Access demand	956,880,000	kwh
CCA Potential	3,827,520,000	kwh
Opt Out est.	5%	
Net CCA 2006 est.	3,636,144,000	kwh

Efficiency Portfolio
EE cap. fact. 20%
EE degrade 1.5% per year

Renewables
Avg. cap fact. 30%

SFCCA plan pg. 32 pdf file

Note: allocations for line losses will depend on siting of renewable and conventional facilities

The City and County has established a bidding requirement for any qualifying Electric Service Provider (ESPs) that it shall install 104 MW of distributed generation such as fuel cells, including 31 MW of photovoltaics, and shall remove 107 MW of load through local conservation and efficiency programs, all within its jurisdictional boundaries. In addition to this 211 MW of load removed from within the PG&E substation, the City and County will also require its ESP to build 150 MW of new wind capacity, either along the path of Hetch Hetchy in conjunction with the San Francisco Public Utilities Commission, or at other suitable locations in or around the Greater Bay Area, as determined in the responses of Electric Service Providers to a Request for Proposals. In sum, San Francisco will not merely comply with the Renewables Portfolio Standard law, but plans to more than double the targets established by SB1078 (2002).

The CCSF CCA will also have to meet the CPUC's Resource Adequacy Requirements (RAR) associated with serving its customers. These rules apply to all electricity suppliers, and require operating and planning reserves of 15-17% in excess of load. In addition, there is a requirement to demonstrate compliance with the rules for the future year's summer peak demand. Also under consideration are resource adequacy rules for LSEs serving specific resource constrained areas. San Francisco is currently a resource-constrained area, therefore the CCSF CCA might have to demonstrate specific in-city resources to serve CCA customers. These rules will have a significant impact on CCA resource planning and ultimately on generation costs for CCA customers.

The City and County has provided adequate notice for PG&E to avoid over-procurement on behalf of San Francisco ratepayers beyond December, 2007. San Francisco's Community Choice program will not impact any multi-year power contracts by Pacific Gas and Electric, as it will not exceed PG&E's assumption that three percent of its current customers will begin to migrate to Community Choice Aggregation in 2006, and 10 percent by 2013 (CPUC Decision 04-12-048, p.26). Under the Total Portfolio approach adopted in D.05-12-041, the CRS calculation will reflect any expected load loss PG&E anticipated in its long-term procurement plan.

PG&E and the CPUC received San Francisco's Community Choice Implementation Ordinance (Energy Independence Ordinance) on May 27, 2004 when Mayor Gavin Newsom signed it. Ordinance 86-04 ordered this Implementation Plan, and established the basic structure that this Plan must follow, both in transaction structure and in portfolio. San Francisco's CCA program will result in a considerable quantity of electric energy efficiency and electric generation within the City, which should result in significant system benefits. The 107 megawatts of conservation and energy efficiency measures, 72 megawatts of distributed generation, as well as a minimum of 31 megawatts of solar photovoltaic modules, will be installed north of the Jefferson-Martin Station, within the jurisdiction of the City. When combined, these facilities will benefit the San Francisco Peninsula's grid, reducing PG&E procurement, the need for new transmission lines to the City, and additional new fossil fuel burning power plants, some potentially outside the City in neighboring Northern California communities.

This Implementation Plan provides that among suppliers, a bidding requirement shall be added that the 360 rollout must be online according to a competitively bid rollout schedule that is sufficiently rapid to pay back H Bonds within the term of the supply contract, while also enabling the supplier to operate profitably. As the aggregate electric demand of San Francisco residents, businesses and government varies between 650 MW baseload and 900 MW peak (and anticipated CCA loads range from 300 MW base to 700 MW peak), the 360 MW resource development that the City and County builds, and the 51% renewables target, will deliver significant environmental, economic and public health benefits, unprecedented since perhaps the construction of the City's water and sewer system a century ago, as well as benefits to regional PG&E grid reliability.

3.2 Consequences for PG&E Energy Efficiency Partnership and Other Programs under CPUC

San Francisco declares its intent to apply to become an administrator of all electric energy efficiency funds collected from CCA customers pursuant to PUC 381.1 (a), or otherwise requests that the Commission now adopt a Decision allowing CCAs to collect their own PGC funds at the same minimum levels required of PG&E, exempting the participating CCA customers from paying into the PG&E PGC Fund. The San Francisco Department of the Environment has historically partnered with PG&E in implementing energy efficiency programs in the City and is currently in negotiations to continue this partnership through 2009. However, in D.05-01-055, the CPUC stated its intention to examine the question of the CCA role in Section 381 fund disbursement.

> "At the same time we recognize that ultimately CCAs are appropriately independent agencies that should have considerable deference to use Section 381 Funds" (D.03-07-034), and have reserved broader issues about CCAs role and discretion for later determination."

The CPUC indicated that it would consider redirecting CCA customer funds from PG&E PGC fund to the CCA if it wishes to administer them directly:

> "Stated another way, we may revisit the question of whether CCA customers should be relieved of their responsibility for energy efficiency PGC and procurement surcharges if the CCA elects to take over these functions. Nothing in this decision prevents us from modifying the process for allocating PGC funds to CCAs in the future"

To ensure the maximum amount of resources are committed to local energy efficiency programs combined with CCA portfolio integration capabilities regarding energy efficiency investments and local control of ratepayer funds, the CCA Program Director (PD), SFPUC and City Attorney shall engage the CPUC to reopen this issue. Upon a resolution of the Board of Supervisors, all PG&E Partnership contracts shall be terminated immediately

3.3 Major Consequences for PG&E 2007—Procurement Contracts, Distributed Generation Interconnection, and Distribution System Upgrades

The major consequences for PG&E resulting from this plan are that San Francisco is preparing to: (1) make a binding commitment to provide commodity service to San Francisco procurement customers within the next year, (2) to request data and interconnection for hundreds of major solar photovoltaic and other renewable distributed generation north of the Jefferson Martin Substation over the next three to five years, (3) install 107 Megawatts of energy efficiency and conservation measures within the City, and (4) install a 150 MW wind farm, potentially using some PG&E transmission capacity. The 360 MW renewable rollout will mean approximately 211 MW of peak load removed from this location within five years, minus growth.

PG&E will no longer have to plan or procure for loads associated with participating CCA customers in San Francisco. At CCSF's request PG&E provided the departments with 12-month energy consumption data and number of customers by rate class for the year 2003. CCSF estimates certain consequences for procurement based entirely on the data provided by PG&E.

CCSF anticipates that PG&E will have to prepare to transfer customers to the San Francisco CCA during 2007. As the CPUC's proceeding to set PG&E's CRS for 2007 is now ongoing, the PD and City Attorney shall begin negotiations as early as March, 2007, relative to making a Binding Commitment to receive customers from PG&E.

The potential amount of load and number of customer accounts that could be served by the CCA are shown below.[1] The load forecast for the CCA's potential customer base was projected from historical data, and CCSF utilized PG&E's system average growth rate of 1.65% as reported in its Long Term Procurement filing (R. 04-03-004) before the CPUC. Assuming that the number of customers will not vary significantly for CCSF, a 0.5% growth rate was applied to the account numbers for all customer classes except Street Lighting and Traffic Controls, which may or may not be included in the CCA load. Charts 1 and 2 below show the 2003 energy consumption and customer accounts by customer-class data. Although the Residential Class alone comprises nearly 91% of all the potential CCA accounts in the City, it represents only 35% of total electricity sales. By contrast, Medium Commercial, Large Commercial and Large Commercial/ Industrial accounts combined represent about 1.0% of the CCA's potential accounts and 52% of electricity sales.

[1] To develop a load forecast for the CCA's potential customer base in 2006, CCSF utilized PG&E's system average growth rate of 1.65% as reported in its Long Term Procurement filing (R. 04-03-004) before the CPUC. Assuming that the number of customers will not vary significantly for CCSF a 0.5% growth rate was applied to the account numbers for all customer classes except Street Lighting and Traffic Controls, which may or may not be included in the CCA load.

Chart 1: 2003 Numbers of Accounts by Customer Class

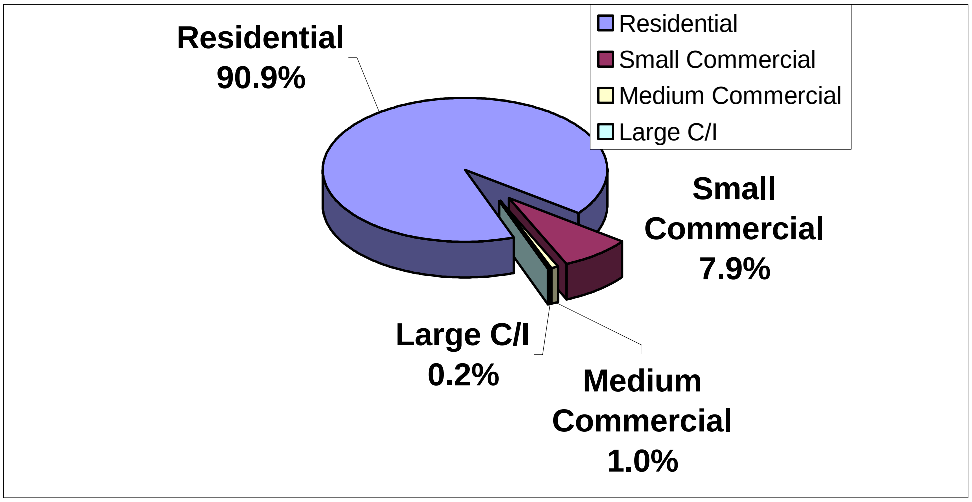


Chart 2: 2003 Energy Consumption by Customer Class

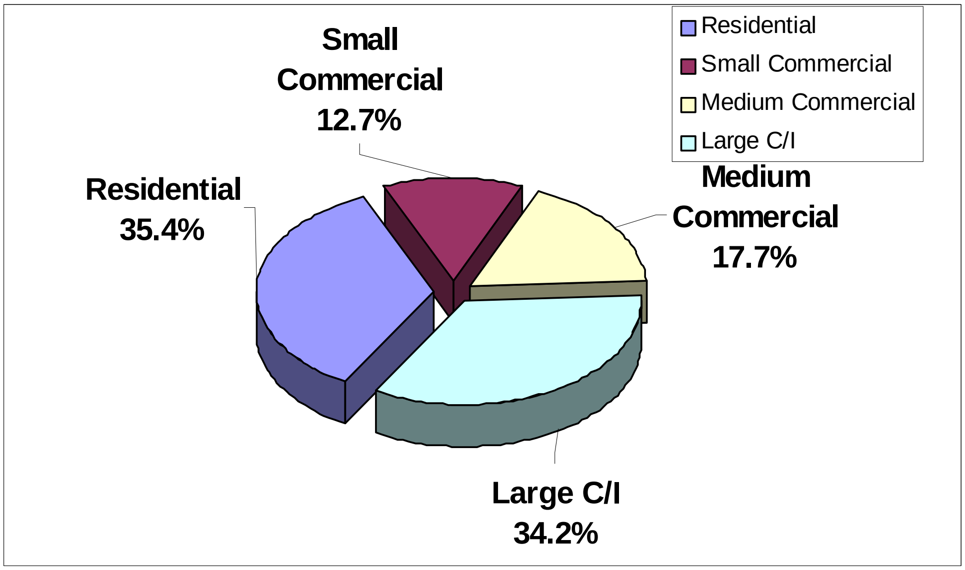
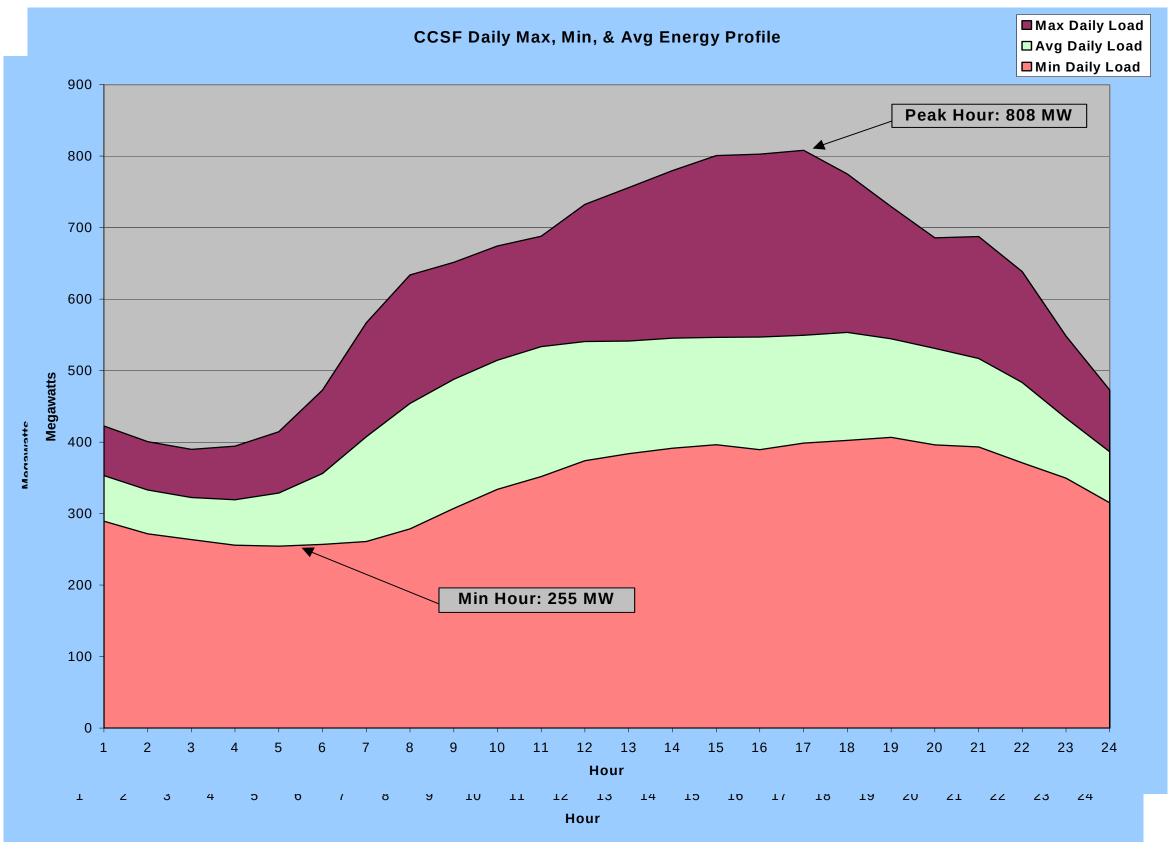


Chart 3 shows CCSF's maximum, minimum, and average hourly energy usage for 2003. CCSF used PG&E's system average load profiles, also known as dynamic and static load profiles, posted on their website to shape monthly energy usage data provided by rate schedule. The CCA's demand peaked at 808 MW in hour 17 (5 PM) and reaches its lowest point in hour 5 (5 AM). However, on average CCA's peak load was between 500-600 MW at 12 through 6 PM, and its minimum load was just over 300 MW at 4 and 5 AM.

Figure 3: CCSF Daily Max, Min, and Avg. Energy Profile 2003



PG&E should prepare, at CCSF's cost, a special "CCA Interconnect" transaction to coordinate and schedule the CCA Supplier's installation and interconnect of the 360 MW rollout of the 211 MW peak shaving equipment, much of which is expected to be eligible for funding under the SGIP, California Solar Initiative (CSI), and other funding structures. This program should interconnect one to three hundred large photovoltaic installations for on-site use, over-the-fence transactions, and islanding of a single building or groups of buildings where customers are prepared to pay the premiums required for islanding— or where public benefits such as

Emergency Medical Response— justify H Bond investment, in which case CCA customers as a whole may pay for and receive islanding services where feasible.

More detail on CCSF's anticipated 360 MW rollout, in particular the timing and development sites, will occur as a result of a successful contract with a bidder. This includes information regarding a 150MW wind farm which may, or may not, connect to PG&E transmission lines.

The precise 360 megawatt rollout schedule will be established by award of contract to a CCA supplier by ordinance, pursuant to AB117. These may or may not be specified in CCSF's Binding Commitment to the CPUC to take customers, and as part of its demonstration of Resource Adequacy, as appropriate. Determinations on the number of facilities and criteria for site selection and approval will be made in the Program Basis Report completed by the PD, which is defined in the Board of Control (BOC) Staffing and Budget. Finally, PG&E should prepare a program of net metering for a limited number of sites, such as smaller sites on residential rooftops. As stated elsewhere, hosting solar photovoltaic facilities will involve a contractual agreement for lease, sale or services, including related energy efficiency services.

An early assessment of potential sites for the five to fifteen other Distributed Generation facilities will be required in a blanket rollout, permitting, site acquisition, and interconnect schedule so as determine and potentially minimize the interconnection costs of such sites, starting in 2008 with physical interconnects needed for dozens of facilities per year, physically connected to the PG&E grid, or another grid, starting in 2008. The rate of rollout has not yet been determined but is expected to require three to five year's duration starting Fall, 2007.

CCSF will also ramp up removal of up to 107 MW of load north of the Jefferson Martin substation, starting in 2007 and concluding on the same 3-5 year approximate schedule. The emphasis will be on either energy efficiency or conservation projects, depending in part on CCSF's ability to administer or directly collect its own energy efficiency Public Goods Surcharge funds, as well as the timing and availability of those funds.

At least 211 MW of renewable energy, conservation measures, and load reductions will occur incrementally starting in Fall, 2007, with SF CCA and SFCCA customer facilities requiring physical interconnects on a weekly basis. San Francisco will pay for the incremental cost of the preparation in order to install the 360 MW facility on a timely basis. Since the CPUC has defined CCAs as captive utility customers for distribution services, the City needs PG&E's full cooperation in the coordination and planning of the CCA RPS portfolio rollout in order to comply with California's RPS law and related CPUC RPS regulation. PG&E can work with CCSF early on, to facilitate and work with the City on interconnection of hundreds of solar installations. Coordination will also be necessary for the estimated 5-15 in-City distributed generation systems, whose size could (for example) vary between 5 MW and 10 MW, and whose fuel usage is assumed to be either renewable, zero carbon, or greatly reduced carbon compared to conventional natural gas or other fossil fuel. Such systems may also involve cogeneration.

3.4 Consequences for In-City Load Reliability Impacts of San Francisco's Community Choice Aggregation Implementation Plan

San Francisco's need for capacity and power across the grid will be dramatically impacted by the 360 MW rollout. San Francisco expects to not only exceed the RPS law, but will provide new green Megawatts and Negawatts to remove a significant portion of the community's aggregate distribution, substation and transmission load.

San Francisco will use revenue bonds and available CPUC and California Energy Commission (CEC) subsidies to finance the following required components of any qualifying supplier's CCA Portfolio.

3.4.1 107 MW Efficiency and Conservation— 3 Year Build Schedule Expected

San Francisco expects the following load reductions to be achieved within San Francisco's jurisdictional boundaries by its chosen supplier:

2008 29 MW
2009 34 MW
2010 44 MW
2010 TOTAL: 107 MW Load Removed, Option for More

This three-year schedule is an estimate. The actual roll-out schedule will appear in the City's Resource Adequacy Demonstration as a Load Serving Entity.

San Francisco declares its intent to solicit an apply to administer approximately the following PGC Energy Efficiency funds on the 2008-10 cycle:

2008 $7 Million PGC EE Funds
2009 $7 Million PGC EE Funds
2010 $7 Million PGC EE Funds

The actual amount will be a pro-rata share based on the electricity consumption of CCA customers and total funding for the PCG energy efficiency program. The ESP will be required to implement the full 107MW of efficiency. The ESP will prepare a contingency plan should the PGC EE Funds not be made available which will address how a shortfall in PGC funding impacts the efficiency build and what reduced MW commitment could reasonably be achieved. If PCG funds are available, the San Francisco Department of Environment will administer such funds and have programmatic oversight and the ESP will actually implement the efficiency measures.

These funds will be supplemented by issuance of H Bonds to finance the 107 MW rollout.

3.4.2 31 MW Solar Photovoltaic and Distributed Generation— 1 Year of Planning and 3 Year Build Schedule Expected

San Francisco expects the following afternoon peak solar photovoltaic to be installed within its jurisdictional boundaries over the period:

2008 0 MW
2009 10 MW Online
2010 10 MW Online
2011 11 MW Online
2010 TOTAL: 31 MW Online, Option of More

This three year schedule is an estimate. The actual roll-out schedule will appear in the City's Resource Adequacy Demonstration as a Load Serving Entity.

3.4.3 72 Megawatts of Distributed Generation Such as Fuel Cells Expected 3 year Build Schedule

Depending on the availability of CEC, CPUC, and other subsidies, San Francisco expects to issue revenue bonds to build several 5 MW or larger renewable or hydrogen or hybrid powered distributed generation facilities.

2008 15 MW
2009 40 MW
2010 17 MW
2010 Total: 72 MW Online with option for more

This three-year schedule is an estimate. The actual roll-out schedule will appear in the City's Resource Adequacy Demonstration as a Load Serving Entity.

3.5 Consequences for In-City or Out-of-City Physical Load Reliability Impacts : 150 MW Wind Farm

CCSF expects the following capacity to be installed on Hetch Hetchy property or other properties in conjunction with the City's Chosen supplier or another entity, as determined by the outcome of its Request for Proposals to suppliers:

2008 0 MW
2009 150 MW
2010 TOTAL: 150 MW Online, Option of More

This schedule is an estimate. The actual roll-out schedule will appear in the City's Resource Adequacy Demonstration as a Load Serving Entity.

3.6 Martin Substation Projected Load Reduced by 2010

This three-year schedule shall be subject to confirmation by negotiation with prospective suppliers, and may be attached to this document upon arrival at the CPUC.

San Francisco's Implementation Plan will reduce 211 Megawatts of peak load north of the PG&E Martin substation on the South Peninsula, meaning physical load will be reduced, for decades into the future, on the ISO's transmission grid, making this capacity available to South Peninsula residents, businesses and institutions, and significantly reducing the need for future transmission upgrades. This is a benefit to all South Peninsula communities.

Hetch Hetchy would benefit disproportionately from an addition of wind capacity physically close to its hydro resource in order to reduce need for hydro throughputs and develop RPS compliant renewable energy resources along its transmission asset, as determined by the San Francisco Public Utilities Commission and Board of Supervisors, and consistent with the Raker Act.

CCSF may elect to site its 150 MW wind capacity on or within reach of Hetch Hetchy properties, and may require transmission capacity on the Hetch Hetchy property, access to ISO transmission capacity, and transmission to connect with PG&E's distribution system serving CCA customers. Sites on the Peninsula, Treasure Island, or other Bay Area locations may also be selected. Further detail on the location of this portfolio component will be disclosed in the Program Basis Report, RFP, Demonstration of Resource Adequacy and Binding Commitment to the CPUC.

The City and County remain interested in acquiring of PG&E's distribution system. In the event that voters approve an initiative creating a financing authority at a future date to pay for such an acquisition, the City and County would have to transition from CCA service to wholesale service as a municipal utility or other public power entity, but will honor all contracts and bond covenants with its chosen Supplier and other parties. All renewable energy and conservation facilities financed by tax-free H bonds shall revert to City ownership at the retirement of the bonds that financed the facilities. Facilities financed by taxable H Bonds may revert to customer or CCA ownership at the retirement of the Revenue bonds that financed the facilities, depending on the agreement made with the customer.

4.0 Organizational Structure

San Francisco's CCA program shall consist of the Board of Supervisors and Mayor authorizing a single Electric Service Provider (ESP) to provide retail electricity and other services to all electricity ratepayers in San Francisco who are not now served by the San Francisco Public Utilities Commission, or otherwise deemed ineligible by the CPUC. The City Attorney shall be charged with enforcing contract compliance.

During the period of the contract between the City and County and its chosen ESP, the ESP may hold title to facilities and contracts, and shall assume all risks associated with its service and competitively bid rates, as well as risks associated with termination due to nonperformance. At the termination of the agreement, the ESP shall transfer the entire product of the renewable resource asset to the City and County of San Francisco (except for those facilities arranged for customer ownership, which shall be transferred according to the terms of the customer agreement), whereupon the City and County shall determine whether to transfer operations of said facilities to a subsequent Electric Service Provider, take them under management of a city agency.

The City and County, an agency, commission or task force, or its chosen contractor who is not a supplier or in any fiduciary relationship with the City's chosen Electric Service Provider or PG&E, shall provide supplemental services to facilitate the successful implementation of this Implementation Plan, including but not limited to data services and representation of the SF CCA, within the terms of nondisclosure agreement requirement set by the Commission.

The San Francisco Public Utilities Commission may act as a merchant wholesaler of renewable capacity and/or energy, including its Hetch Hetchy assets and potential new RPS compliant assets, in relation to the City's Chosen Electric Service Provider, as determined by the Board, Mayor and SFPUC Commissioners, but this potential shall depend upon the ultimate outcome of the City and County's chosen competitive bidding process, and cannot be determined by the City and County as of the date of this Implementation Plan.

4.1 Board of Control

While the CCA program will ultimately become a department of the San Francisco Public Utilities Commission (SFPUC), AB117 requires the project to be governed by the Board of Supervisors. Therefore, this Implementation Plan creates a special Board of Control (BOC) to administer a single-purpose group of experts to perform work related to establishing the program. As AB117 requires the CCA program to be governed by the Board of Supervisors and Mayor through its chosen agencies, the BOC will provide the City's top elected officials with direct oversight of the CCA team through the BOC. The San Francisco CCA shall be represented at the CPUC, CEC, or other state and Federal agencies by the City Attorney's office assisted by BOC staff. This Implementation Plan, as adopted by ordinance, establishes and funds the San Francisco Community Choice Aggregation Board of Control, and authorizes the BOC to implement the San Francisco Community Choice Aggregation Program in conjunction with the SFPUC and Board of Supervisors.

This Implementation Plan shall go into effect immediately, upon its adoption by ordinance. Adoption of this Plan creates and provides initial funding for the Board of Control (BOC), a special single-purpose entity tasked with the implementation of the CCA Program as an independently run and staffed start-up enterprise of the San Francisco Public Utilities Commission. The CCA Board of Control created by this Plan shall consist of five city leaders who shall meet periodically to make operational oversight and fiscal decisions regarding implementation of the program. The BOC will appoint a Program Director (PD) to run the CCA program. The BOC will also work with city departments to identify staff that will be assigned to participate in the CCA Program. The BOC will establish a program staff solely dedicated to the implementation and success of the CCA Program, and will be provided with the required resources to advance the Program.

The BOC will appoint the PD from candidates identified by the Human Resources Department (HR), which shall conduct a 30-day national search; beginning on the date this ordinance goes into effect. The BOC will approve the PD's selection of contractors and City employees to manage as participants in the implementation of the CCA program. The BOC shall make periodic reports to the Mayor, the Public Utilities Commission, and the Board of Supervisors regarding the implementation of the CCA program. The BOC shall approve major PD expenditure decisions, and report to the Board of Supervisors and Mayor, which are responsible under AB 117 for the governance of the CCA program. The BOC is authorized to approve expenditures of available SFPUC funds, but must have approval of the SFPUC for expenditure of SFPUC CCA program reserve funds.

The Chair of the BOC shall convene the members of the Board of Control within 45 days after this ordinance goes into effect to evaluate candidates identified by HR. After the selection of a candidate for the PD position, and the acceptance of the position by the candidate, the BOC shall convene the members of the Board of Control to formally record the appointment of the PD and to approve the initial budget of $1M for the PD to begin work immediately, review, edit and complete a draft RFI prepared by the CCA Stakeholder Group and the City and County's Community Choice Aggregation Task Force.

The PD shall submit a draft "Request for Information" (RFI) for approval by the BOC within 30 days after the appointment of the PD. Within two weeks of the date the RFI is approved by the BOC, the PD shall publish it in every major Bay Area newspaper, the largest circulation newspaper of every California county, as well as in major national and international energy industry and alternative energy industry and public works industry trade publications. The RFI shall require respondents to submit responses to the RFI within 45 days of the date of publication.

The PD shall prepare and submit a report and recommendations on the RFI responses (along with copies of the responses themselves) to the BOC within 15 days after the closure of the RFI process. The report shall identify the information gathered through the RFI Process that should be considered in the further development of the CCA Program, and the particular CCA supplier solicitation documents (RFQ, RFP, etc.) The Report shall also contain the PD's recommendations regarding the schedule, and next steps in CCA implementation as well as draft Requests for Qualifications and, if appropriate, draft Program Basis Report and draft Request for Proposals documents.

Within 10 days of receipt of the PD's report on RFI responses, the BOC Chair shall convene a quorum of members to evaluate the PD's report and recommendations, and to adopt the schedule, process and budget authorization for the PD to proceed with the preparation of a Program Basis Report and associated work product to provide the basis for a draft CCA Request for Qualifications and Request for Proposals (RFP).

The following timeframes are expected for the development of the Program Basis Report, Draft Request for Qualifications and draft Request for Proposals:

Item	Deadline
Program Basis Report	Depending upon the level of detail and assessment required in the RFP, this report could vary from 60 to 180 days from PD authorization to proceed
Draft Request for Qualifications	60 days from completion of the Program Basis Report
Draft Request for Proposals	90 days from completion of the Program Basis Report

The PD shall be required to provide a justification to the BOC for proposed durations greater that those identified above.

Within 15 days of receipt of the draft Request for Qualifications the BOC Chair shall convene a quorum of members to evaluate a draft RFQ, approve or request further work on a resolution adopting the draft RFQ prior to recommending it to the Board of Supervisors, and recommended date for the PD to submit CCSF's CPUC CCA IP Compliance Document to the Board of Supervisors for amendment and adoption, pursuant to Ordinance 86-04.

Within 15 days of receipt of the draft Request for Proposals, the BOC Chair shall convene a quorum of members to evaluate a draft RFP, and an Open Season strategy, and shall approve or request further work on the draft RFP prior to recommending it to the Board of Supervisors.

The Board of Supervisors shall hold hearings on a resolution amending and/or approving the RFQ and RFP for publication at its next regularly scheduled Government Audit & Oversight Committee meeting, which shall make any amendments on an expedited basis and refer the document to the Board of Supervisors to authorize, by resolution, the PD to publish the RFQ and RFP immediately in the manner required by this Plan.

The PD shall amend and/or submit CCSF's CPUC IP Compliance Document to the CPUC on the date approved by the Board of Supervisors. This action will be followed by the CPUC's statutorily defined 90-day certification process pursuant to Public Utilities Code Section 366.2(c)(7), and any additional information requested by the CPUC in order for it to present its findings regarding any cost recovery that must be paid by participating San Franciscans to prevent a shifting of costs as provided for in subdivisions 366.2 (c), (d), (e), and (f).

The PD shall submit a binding commitment document for the CPUC to the Board of Supervisors for approval by the Board of Supervisors to coincide with the award of the Contract.

4.2 Start-Up, Organization, and Funding of the Program

As discussed in the Implementation Plan, there are a number of critical elements that must be advanced in parallel for the CCA Program to be successful. The BOC has the responsibility of reporting publicly to the Mayor and the Board of Supervisors regarding the implementation of the CCA program in conformance with the adopted Implementation Plan, including the expenditure of appropriated funds and the expenditure of revenue bond proceeds on the City's CCA resource portfolio. The BOC is established to advise and help guide the implementation of the program in a manner that involves the residents and businesses that are CCA customers.

Beyond its functional responsibilities, the CCA Program will also have the duty to safeguard confidential data pertaining to current electric utility corporation customers, which PG&E is required to provide under Public Utilities Code Section 366.2 (c)(9). Throughout the course of the CCA Program, appropriate measures will be needed to ensure that confidentiality is maintained. The Board of Control is hereby authorized by the City to request, receive and manage all data from the electrical utility corporation, and will apply the appropriate means and resources to manage the information such that strict levels of confidentiality are preserved.

4.3 Board of Control Authorities and Powers

The San Francisco Community Choice Aggregation Board of Control is hereby created for the purpose of implementing the San Francisco Community Choice Aggregation Project, as generally described in ordinance 86-04 (May 27, 2004), as described in this Implementation Plan, and as specifically provided in sections (a) through (d) below:

(a) The Board of Control has all of the powers necessary for planning, designing, implementing, and building the Project, including, but not limited to, all of the following:
(1) Application for and acceptance of grants, fees, and allocations from any federal, state, local agencies, and private entities that may be available for the advancement or benefit of the Project
(2) Acquiring, through agreement, lease, purchase or through eminent domain proceedings, any real property or property rights necessary for, incidental to, or convenient for, the implementation and management of the Project
(3) Preparing the Board of Supervisors for the issuance of revenue bonds to fund the elements of the Project pursuant to San Francisco Charter Section 9.107.8

(4) Negotiating with energy suppliers and preparing the Board of Supervisors to contract with public or private entities or individuals for services for the planning and implementation of the Project, and for the design, construction, operation and maintenance of the Project, in accordance with all applicable City of San Francisco procurement requirements, processes and guidelines
(5) Entering into cooperative or joint development agreements with other City or other municipal government entities or private entities. These agreements may be entered into for the purpose of expanding the jurisdiction of the CCA Program, sharing costs, selling or leasing land, air, or development rights, or for any other purpose that is necessary for, incidental to, or convenient for the full exercise of the powers granted the Board of Control. For purposes of this paragraph, "joint development" includes, but is not limited to, an agreement with any person, firm, corporation, association, or organization for the operation of facilities or development of Projects adjacent to, or physically or functionally related to, the Project
(6) The exercise of all rights and powers conferred upon municipalities choosing to form community choice aggregations under State law AB 117, California Public Utilities Commission Decisions 04-12-046 (December 16, 2004) and 05-12-041 (December 15, 2005), except those requiring specific actions by the Board of Supervisors and/or Mayor
(7) officially representing the project to the public, the media and governmental and regulatory entities
(8) Relocation of utilities, as necessary for completion of the Project
(9) Securing any permits required for the implementation of the Project
(10) requesting, receiving and managing all data from the electrical utility corporation that PG&E is required to provide under Public Utilities Code Section 366.2 (c), as well as any other data possessed by departments or agencies of the City and County.

(b) the duties and responsibilities of the Board of Control include, but are not limited to, all of the following:

(1) Officially submitting the San Francisco Project Community Choice Aggregation Implementation Plan to the California Public Utilities Commission, as required under State Law AB 117,
(2) Implementing the CCA Project as described in the San Francisco Community Choice Aggregation Implementation Plan,
(3) (A) Adoption of administrative procedures, not later than 60 days after the adoption of this Ordinance for the administration of the Board of Control in accordance with any applicable laws, contracting and procurement laws, laws relating to contracting goals for minority and women business participation, and the Political Reform Act of 1974 (Title 9 (commencing with Section 81000) of the Government Code),
(B) The administrative procedures adopted under subparagraph (3)(A)shall include a code of conduct for staff and Board of Control members that is consistent with Sections 84308 and 87103 of the Government Code,
(C) The administrative procedures adopted under subparagraph (3)(A)shall include the establishment of all financial management procedures and processes to be used for the implementation of the CCA Project, including the establishment of bank or other accounts necessary for the management of all Program funds,

(4) Submitting quarterly progress and budget reports to the Board of Supervisors over the course of the implementation phase,

(5) Preparation of proposed annual CCA Project Implementation Management budgets for approval by the Board of Supervisors

(6) The Board of Control is responsible for implementing all measures necessary to safeguard confidential data pertaining to electric utility corporation customers.

(c) The Board of Control shall consist of five members serving as follows:

(1) One member shall be the Mayor or an Alternate appointed by the Mayor from the Mayor's staff to attend meetings in which the Mayor is unable to be present. This member shall be the Vice Chairperson of the Board of Control

(2) Two members shall be the President of the Board of Supervisors, who shall be the Chairperson of the Board of Control and a Supervisor appointed by the President of the Board of Supervisors,

(3) One member shall be the General Manager or the President of the San Francisco Public Utilities Commission, as determined by the Commission, which shall appoint an Alternate Commissioner to attend meetings in which the appointee is unable to be present.

(4) One member shall be the City Controller,

(5) All appointed members shall serve a term of not more than two years, with no limit on the number of terms that may be served by any person. Renewal appointments shall be made by the original appointing body.

(6) If the position of a voting member becomes vacant, an alternate voting member may be appointed by a majority vote of the board to serve until the position is filled as required under this subdivision (c).

(7) Members of the board are subject to the Political Reform Act of 1974 (Title 9 (commencing with Section 81000) of the Government Code).

(8) Three members of the Board of Control shall constitute a quorum. The Board of Control shall meet monthly and more frequently if requested by the Chairperson, and shall vote on all documents that have been submitted by the Program Director at least seven (7) days prior to each Board of Control meeting.

(9) A full time Program Director shall be responsible for managing the implementation of the CCA Program. The Program Director will report to the Board of Control, and will serve at the pleasure of the Board of Supervisors. The Board of Control shall appoint the Program Director , and shall appoint subsequent Program Directors. The Program Director may be retained as a City employee, or under a services contract with the Board of Supervisors. The Program Director must be knowledgeable and qualified in all of the following areas: California's Community Choice Aggregation law AB117, San Francisco's Ordinance 86-04, the California Public Utilities Commission's CCA regulations, the City's H Bond Authority, San Francisco's CCA program strategy, design build operate maintain contracting methods, multi-site acquisition, and industrial facility permitting.

(10) The Program Director may recommend the appointment of existing city staff, hiring staff or contracting for staff, for the approval of the Board of Control. Staff positions may include the following:

- Financial Manager
- Contracts Manager
- Technical and Project Managers
- Communications/Outreach/Customer Service Manager
- Property Acquisition Manager
- Construction Manager

If existing city staff are assigned to support the implementation of the CCA program, any such staff members must be assigned full-time, and the roles of these staff members will be set by the Program Director, subject to Board of Control approval. All such staff shall report to the Program Director. The Program Director will determine whether consultant and legal services will be required for the implementation of the Program, and prepare requisitions for the procurement of any such services for Board of Control Approval and recommendation to the Board of Supervisors, as provided in Article 1.(a)(4) herein.

(11) If retained as employees, the Program Director and staff (other than existing city staff) shall be paid salaries established by the Board of Control.

(12) The Program Director shall prepare all procurement documents necessary for the award of the single contract for the ESP, including Requests for Information (RFI), Requests for Qualifications (RFQ) and Requests for Proposals (RFP), for Board of Control approval and recommendation to the Board of Supervisors, as provided in Article 1.(a)(4) herein.

(13) All contracts prepared for Board of Supervisors award shall be awarded in accordance with all State and City laws relating to procurement; including all DBE/MBE requirements and in cooperation with the Mayor's Office of Economic and Workforce Development. Contract awards may be based on price, other factors, and competitive negotiation, or on all of these criteria.

(14) The Program Director shall manage the PG&E interface, city agency interface, and permitting.

(15) The Program Director shall be responsible for the preparation of draft quarterly progress and budget reports for Board of Control approval and submission to the Board of Supervisors over the course of the implementation phase,

(16) The Program Director shall be responsible for preparing annual performance evaluations for all staff.

(17) The Program Director shall be responsible for evaluating the administrative needs for the successful implementation of the Program, including the determination if there is available city office space for the program, and what equipment, supplies and administrative services, (such as graphic and printing, records management, couriers, etc.) will be necessary for the management of the program, and for allocation of appropriate amounts of the budget for these costs.

(18) All documents to be considered by the Board of Control for approval must be submitted by the Program Director to the Board of Control Chairperson at least seven (7) days prior to the next scheduled Board of Control Meeting.

(d) The Board of Control shall be dissolved, as determined by the Board of Supervisors, upon completion of all activities necessary for the implementation of the Project, including any additional CCA Program implementation activities subsequently approved by ordinance, or upon termination of the CCA Program by the Board of Supervisors. Prior to the dissolution of the Board of Control, the Board of Control shall prepare for an orderly transition of responsibility for the Project to the San Francisco Public Utilities Commission for regular operations.

4.4 CCA Program Budget and Funding

San Francisco ordinance approves and authorizes the use of $5 million in funding for fiscal year 06-07 for the implementation of the CCA Program, $3.2 million of which is placed on reserve pending information regarding progress on CCA start-up. The Program Director may make expenditures from the amounts hereby approved and authorized for all purposes relating to the implementation of the program; including staff costs, support services costs, and administrative costs such as office space, equipment and supplies.

The Program Director shall manage the budgets necessary for the implementation of the CCA Program, at a strict level of financial diligence, in order to ensure that the program does not exceed its authorized funding levels. The Program Director shall provide detailed quarterly financial reports to the Board of Control.

The Board of Control shall prepare and submit subsequent annual budget authorization requests based on actual SF CCA Program resource needs to the Board of Supervisors for approval.

5.0 SFPUC and Supplier Functions and Scope of Responsibilities

Ordinance 86-04 requested that this Implementation Plan identify the operations of the CCA as well as the functions that should be performed by entities other than the City, including a power supplier and/or its subcontractors.

The SFPUC's Power Enterprise currently provides electric power to electric customers of the City and County of San Francisco. The Power Enterprise currently manages a portfolio of resources that includes Hetch Hetchy hydroelectric generation, a supply contract with Calpine, and third party purchases. Consistent with the SFPUC's commitment to cleaner and greener power supplies, the Power Enterprise has begun diversifying its existing resource base to include renewables, distributed generation, demand management and energy efficiency programs.

Under CCA the Power Enterprise would provide the "public face" functions for the program. Public face functions include:

- Customer service and administration of a customer call center
- Customer opt-out processing
- Management of energy efficiency programs

5.1 Associated Governmental Process

The CCA Program will involve a number of other governmental entities as it is implemented. Examples of the processes involving other governmental agencies include obtaining permits to using sites owned by other governmental agencies to securing any benefits available through governmental clean power and efficiency programs. In addition to formal involvement, the CCA will be a high visibility program, and as such, it will benefit the program to build and maintain political support.

In order to effectively manage all required governmental involvement, the CCA Program will first work to identify all of the City, State and Federal governmental agencies that will be involved by the nature of their jurisdictions. This will include all agencies that will need to provide any form of permits or other forms of approval for the CCA Program to advance, as well as agencies that have oversight roles. It will also include descriptions of all interface responsibilities that the CCA Program and the involved agency will have during the implementation and subsequent operation of the CCA Program.

It is expected that the main areas of intergovernmental involvement will relate to the establishment of a CCA, to customer protection measures, and to the environmental and other land use regulations that may be involved in the installation of the renewable power generation infrastructure.

When all of the CCA Program's intergovernmental responsibilities have been identified, a schedule of required CCA activities will be developed to support the overall timing requirements of the program. Depending on the volume, nature and skill sets required, appropriate staff resources will be assigned to address the CCA's intergovernmental responsibilities.

The previous work in San Francisco to install solar power generation equipment at the Moscone Center and the Generation Solar program have served to familiarize and prepare affected City agencies for working with renewable power technology installation. It is expected that the CCA Program will benefit from progress made through these efforts.

In addition to intergovernmental responsibilities that the CCA Program will have, it may also be able to benefit from other governmental activities. A number of governmental agencies have ongoing programs in clean energy and conservation. From acquiring specific technology assistance or equipment, to participating in emissions trading, to gaining the benefits of research, there may be significant benefits to the CCA Program available through other complementary governmental agency efforts.

The CCA Program will first categorically identify all such complementary programs, and the specific benefits they make available. Then, depending on the nature of activities required to secure these benefits, appropriate staff will be assigned to coordinate the CCA Program's efforts to participate with these complementary governmental agency programs.

5.2 Rate Design, Ratesetting and Other Costs to Participants

This section explains the process by which CCA rates and other costs will be established, including public participation in that process.

Public Utilities Code Section 366.2(c) 3 (B) and (C) require San Francisco's Implementation Plan to contain rate-setting and other costs to participants. The City and County interprets this requirement to mean information regarding the basic principles and structure of its rate-setting mechanism. This is not a submission of CCA rates to the CPUC for approval.. Therefore, the City and County's ratesetting mechanism is not required to conform to a CPUC regulated approach t to setting the CCA component of rates.

> Ordinance 86-04 requires that this Implementation Plan require that the supplier bids and any contract with an supplier include proposals for CCA rate design, with all costs associated with providing the various components of the City's proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid to the City (Ordinance 86-04, Section 3 (1)(III), p.5).,

Furthermore, Ordinance 86-04 establishes a second RFP bidding requirement that the bidder "shall post a bond or demonstrate insurance sufficient to cover the cost of reentry fees in the event that customers are involuntarily returned to service provided by PG&E," and shall bid "an insured electricity rate schedule, similar to that appearing on monthly bills" (Section 4 (E), p.9).

The first new element of the City and County's rate-setting mechanism established by this Implementation Plan is a requirement that the supplier's required rate schedule shall also include all City staffing and expense costs that are directly related to the CCA program. This will require that staff present a assessment of the likely City CCA costs in its RFP process to enable bidders to account for such costs in their bids. A second new element not identified in Ordinance 86-04 is the requirement that the supplier assume any and all liabilities of meeting the resource adequacy requirement for all LSEs contained in the CPUC Decision 05-10-042 and subsequent decisions expected the Summer of 2006 regarding the local component of meeting resource adequacy. A third element included for clarity is that the supplier will also have to manage, within its competitively bid schedule, any CRS true-up balances that will be calculated by the CPUC relative to the Cities CCA program. In addition to these costs the supplier must also incorporate the costs of any fees charged to the CCA by PG&E, and account for the customer responsibility surcharge (CRS) in its bids so as to establish a clear comparison to PG&E energy rates.

Under the City and County's rate-setting mechanism, the supplier shall be required to manage the risks associated with its competitively bid rate schedule, such that a misprojection of the cash needs of the supplier, under which a misallocation of unanticipated costs and overheads by the supplier shall not be recovered from participating San Francisco ratepayers, but shall be born by the supplier's owners or another party that underwrites or enhances the credit of the supplier. In this manner, the City and County's award of contract to a supplier shall constitute its major action as a rate-setting authority within the scope of this Implementation Plan, except for any decision to increase development of renewable resources, conservation or energy efficiency technologies through a contract extension and subsequent bond issuances by the Board of Supervisors to achieve a 51%RPS by 2017

While the rate-setting function of San Francisco's CCA program is neither regulated by the CPUC nor limited to cash needs approach of municipal utilities, the City's rate-setting function must be reasonable, and may also be subject to charter and/or municipal code restrictions, including bond covenants (The California Municipal Law Handbook, p.IV-78 (2002 ed). Specifically, San Francisco's Charter authorizes the Board of Supervisors to provide for the issuance of revenue bonds "to finance or refinance the acquisition, construction, installation, equipping, improvement or rehabilitation of equipment or facilities for renewable energy and energy conservation, in accordance with state law or any procedure provided for by ordinance (San Francisco Charter Section 9.107.8).

5.1 Treatment of Low-Income Customers Requires Special Consideration

A key aspect of residential rates regulated by the CPUC is the California Alternative Rates for Energy program (CARE). This program applies to residential customers of PG&E and other investor-owned utilities and provides about a 40% discount from average total residential bills for customers with incomes up to 175% of the Federal poverty line. In CCSF about 17% of residential customers are currently *participating* in CARE.[8] This is slightly lower than the 21% of PG&E's residential customers that are participating in CARE system-wide. Moreover, according to PG&E the CARE program has a higher penetration rate in San Francisco (82%) than it does on average throughout PG&E's system (70%). This means that there are fewer customers eligible for CARE and not participating in the program in San Francisco than in the rest of PG&E's service territory. Within CCSF these customers currently have average monthly bills of $26.27 of which $8.79, or 33% is constituted by the generation portion. Based on CPUC Decision 05-12-041 the City anticipates that CARE program funds will be made available to CCA CARE eligible customers such that these customers should be no worse off under the CCA program than under PG&E rates.

6.0 Provisions for Disclosure and Due Process in Setting Rates and Allocating Costs

Consistent with Section 2.2.3 "Rate Design, Rate Setting and Other Costs " above, this section describes how the CCA will disclose to its customers and governing board information about rates and costs, and the public participation process for rate setting and cost allocation proceedings.

The City and County will ensure that adequate notice is provided to electricity customers during the rate-setting process, which consists of the RFP process, the award of contract by ordinance and opt-out notifications. Towards this purpose, and consistent with the Sunshine Ordinance and open meeting laws, the City and County will continue to conduct public hearings at every juncture of the CCA decision-making process, and shall provide notifications to customers as required by 366.2(c)(13)(A), (B) and (C), using a single page insert with a detachable postage-paid opt-out card, in which the City and County shall fully inform participating customers at least twice within two calendar months, or 60 days, in advance of the date of commencing automatic enrollment. Notifications may occur concurrently with billing cycles.

Following enrollment, the City and County shall fully inform participating customers for not less than two consecutive billing cycles. Notification in power bill inserts may be supplemented by direct mailings to customers, or inserts in water, sewer, or other utility bills. Any notification shall inform customers of both of the following:

(i) That they are to be automatically enrolled and that the customer has the right to opt out of the community choice aggregator without penalty during the opt out period.

(ii) The terms and conditions of the services offered.

Toward this purpose, the Board of Supervisors has requested the Commission to order PG&E to fully cooperate with the City and County in determining the feasibility and costs associated with using the electrical corporation's normally scheduled monthly billing process to provide all four (4) of the notifications required pursuant to subparagraph (A) by inserting the City and County's notification in the electrical corporation's normally scheduled monthly billing process. Consistent with AB117, the City and County will pay the reasonable cost the electrical corporation shall be entitled to recover from it all reasonable incremental costs it incurs related to the notification or notifications, as determined by the Commission.

Furthermore, Ordinance 86-04 establishes that this Implementation include a requirement that qualifying ESP bids shall offer a rate schedule comparable to PG&E's so that ratepayers may competently judge whether to opt-out of the City and County's chosen new energy service:

> "The RFP shall require that bids by prospective Electric Service Provider shall include a proposed rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid, to be reflected in a per kilowatt hour rate schedule that is comparable to PG&E's rate schedule and consistent with the resource portfolio requirements and rate-setting mechanisms contained in the City's adopted Implementation Plan" (Ordinance 86-04, Section 4(D), pp.8-9).

Furthermore, Ordinance 86-04 requires that the Implementation shall include a similar provision that ESP rates shall include all costs, inclusively, of the bundled product:

> "Appropriate contract and bid requirements, including...III. A requirement that bids include proposals for rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid" (ordinance 86-04, May 27, 2004, p. 6).

Pursuant to Public Utilities Code 366.2 (c)(13)(C), each notification shall also include a mechanism by which a ratepayer may opt out of community choice aggregated service. The opt out may take the form of a self-addressed return postcard indicating the customer's election to remain with, or return to, electrical energy service provided by PG&E, or another straightforward means by which the customer may elect to derive electrical energy service through the electrical corporation providing service in the area.

Another risk reduction option would be for the CCA to also levy an exit-fee of some type on customers who leave the CCA for other electric service after the statute mandated free opt-out period.

Finally, the Board of Supervisors shall require that ESP rates shall include costs associated with managing the risks of an annual true up of the CRS pursuant to D.04-12-046.

If a customer declines to opt-out but later wishes to return to PG&E service, it will face CPUC-imposed switching rules to return to PG&E service. These rules might include a minimum time on rates tied to wholesale electric spot prices and/or a minimum commitment to remain a PG&E customer.

CCA supplier may propose to CCSF a) to adjust its rate in relation to PG&E's rates or, b) a structured rate changing by a fixed percentage per year. (INSERT TERMS OR OPTIONS HERE).

11.1 CCA Advisory Board

Prior to the initiation of Basic Service from the supplier, the SF PUC Commissioners' President will enlarge the terms of reference of the existing SFPUC Rate Fairness Board to incorporate CCA related matters. The Rate Fairness Board will be responsible for: 1) monitoring the rates charged by the supplier, and reporting any deviations from the contract rate-setting provisions to the SFPUC Commissioners and 2) for monitoring the resolution of customer complaints, and reporting complaints that are not resolved by the supplier within reasonable periods to both the Board of Supervisors and the SFPUC Commissioners, and 3) for monitoring the supplier's performance as it relates to significant energy market events, and advising both the Board of Supervisors of any energy market conditions that may effect the supplier's performance, and 4) monitoring the supplier's overall performance under the Contract. The Rate Fairness Board will prepare the Quarterly Report and Annual Report to be submitted to the Board of Supervisors as detailed below.

11.2 Supplier Rate Review

The Rate Fairness Board will conduct a quarterly review of the rates charged by the supplier across all customer rate classes, to confirm that all supplier rates are in full compliance with the contract's rate setting provisions. The Rate Fairness Board Annual Report will include a rate compliance report documenting the supplier's compliance with the contract rate setting provisions over the previous six months.

11.3 Complaint Monitoring

The Rate Fairness Board will maintain a record of all customer complaints received by the CCA Program, and a record of the party assigned to take primary responsibility for resolving the complaint (supplier, PSE&G, CCA Staff, etc.) The Board's Quarterly Report will 1) identify the complaints received during the past quarter by category of complaint, using categories developed by the Board, 2) identifies complaints by category that were resolved during the reporting period, 3) identifies the number of open complaints pending resolution, and 4) identifies any complaint issues where there the Board has any significant concerns relative to the resolution of the complaint.

11.4 Energy Market Monitoring

The CCA Advisory Board will monitor energy market conditions and trends that may directly or indirectly affect the ESP's performance and/or costs of energy provided by the ESP. Because of the nature of energy market fluctuations and conditions that effect energy costs, the CCA Advisory Board will advise the Board of Supervisors on an as-needed basis of any energy market conditions that arise that may affect the ESP's performance, as well as reporting on all such conditions in the CCA Advisory Board Quarterly Report. In instances where longer term trends are reported on, the CCA Advisory Board Quarterly Report will include appropriate data supporting the reports conclusions.

11.5 ESP Performance Monitoring

The CCA Advisory Board will monitor the overall performance of the ESP on an ongoing basis, and will advise the Board of Supervisors of open issues and any areas of concern relative to the ESP's performance, based on urgency as such issues arise, as well as reporting on the ESP's overall operational performance in the CCA Advisory Board Quarterly Report using performance metrics developed by the CCA Advisory Board.

7.0 Methods for Entering and Terminating Agreements

The Board of Supervisors shall enter into agreement with its chosen ESP by ordinance, and any termination of such agreement shall also be undertaken by ordinance. The City and County is limiting its contract offer to registered Electric Service Providers. The resulting contract, should it be awarded, will consist of a formal agreement delineating purchase and service responsibilities (The California Municipal Law Handbook, p.IV-76, 2002 ed.).

Ordinance 86-04 provides that the ESP shall transfer ownership, upon termination of a CCA ESP agreement, of all online and functional H Bond financed renewable energy, energy efficiency or facilities to the City and County.

Additional information on the subject of Termination is presented below in Section 14.

8.0 Rights and Responsibilities of Program Participants, Including Consumer Protection

Rules and procedures previously developed for Direct Access, and those currently in effect for municipal-owned utilities in California, are directly applicable to San Francisco's CCA Program in many cases. Customer-related rules and procedures need to address areas such as:

- consumer protection
- application for service
- notifications
- billing
- payment of bills
- establishment of credit
- maintenance of credit
- reestablishment of credit
- deposits
- billing adjustments
- billing disputes
- discontinuance of service
- shut-off
- relocation of service
- restoration of service
- return to IOU service

(INSERT DETAILS ON RIGHTS AND RESPOSIBILITIES FROM RFI RESPONSES, RFP RESPONSES AND/OR CCA CONTRACT HERE BEFORE SENDING TO CPUC)

9.0 Program Termination

While the whole purpose of a comprehensive implementation plan is to ensure a successful program. To protect ratepayers the City must always have the option of terminating an ESP contract and/or terminating the entire CCA program. In such an instance, the City must continue to provide power to customers through another means. In a termination scenario, continued service could be provided though an alternate ESP, the City itself (as a municipal utility), or by reverting back to the investor owned utility.

Contractual and technical terms for termination will be spelled out in detail in the ESP RFP and ultimately in the contract with the selected ESP. Termination clauses will be designed with care, as they can translate into potential risk for ESP’s and therefore may manifest themselves in higher program costs.

The costs associated with termination and continued service must not result in costs above the “meet or beat” rates under the ESP rate proposal. Any costs falling outside those limits must be borne by the termination itself, for example, through the performance bond of the ESP, legal proceedings for non-performance, or financed through savings expected from the change, for example, by changing ESPs.

CCSF will expend considerable political and financial resources to become a CCA and will likely enter into a multi-year contract with an Energy Service Provider which could be worth as much or more than a billion dollars. Investing in renewable energy and energy efficiency projects using Prop H Bonding will also involve a multi-year commitment from CCSF. Termination of the CCA program would involve complex and costly unwinding of these commitments.

In the case of ESP failure or breach of contract, CCSF would likely pursue its contractual rights, while also signing a new contract with an alternative supplier. In this case, there are some common issues and impacts:

- Notification must be made to all CCA customers
- Customers must be switched back to utility service, according to rules not yet developed by the CPUC
- Legal proceedings are likely to be required to address contract issues with the ESP and possibly generators owned or contracted through CCSF
- Legal proceedings are likely to be required to address any bonding commitments made for any power production where CCCSF is a part owner
- CCSF will likely need to perform staff reassignment or lay-off

Provisions to address possible ESP default are required in the contract, including a termination for default provision and a remedy to insure the CCSF is not harmed by the default. Credit and financial assurance provisions as described below are also key provisions to address ESP default.

10.0 Credit and Financial Assurance

The CCSF will need to establish credit and financial assurance policies and procedures that protect it in the event a CCA Program Counter Party fails to meet its obligations. The policies and requirements imposed upon third parties by the CCSF will need to be specified in the supply contract or in a separate credit agreement.

These policies are likely to result in specific contractual provisions and related CCSF responsibilities. The primary responsibilities can be categorized as follows:

- credit application and creditworthiness process
- security process
- creditworthiness monitoring process
- credit policy evaluation process

The CCSF will need to adopt specific provisions in the supply/credit agreement that both protect it from credit exposure and encourage a large number of bidders. Balancing these often opposing objectives will require a specific strategy and set of policies. Common credit provisions are listed below.

- Termination payment provisions (liquidated damages) – in the case of default, provides the CCSF with compensation for the underlying value of the contract. Commonly calculated by taking the discounted present value of the positive or negative difference obtained by subtracting the value of a replacement contract from the existing contract.
- Step up provisions (under a multiple provider CCA Program) – in the case of default by an ESP, other contracted ESPs take on the defaulting parties' supply obligation usually by offering an option, not an obligation to the non-defaulting parties.
- Credit threshold and credit limit provisions – based on credit policies, there will be varied requirements for establishing and managing credit of ESPs under a CCA Program.
- Mark to Market credit exposure calculation – credit exposure is commonly measured through mark to market calculations that made daily or weekly based on market prices of electricity. These provisions require the ESP to post security according to the value of the contract. Credit exposure calculations commonly have margin call provisions as well, which specify the terms and conditions that a counter party obtains security from an ESP when it exceeds credit thresholds.

11.0 Termination for Convenience Provisions

"Termination for Convenience" provisions are common in municipal government contracts, but present potentially substantial risk to ESPs. These provisions provide the right to terminate the contractor's performance without the government being liable for breach-of-contract damages.

In addition to these general credit concerns, AB 117 also imposes a specific deposit requirement upon CCA and the proposed language of the RFP in Ordinance 0086-04 mirrors this language in stating that "qualifying Electric Service Providers post a bond or demonstrate insurance sufficient to cover the cost of reentry fees in the event that customers are involuntarily returned to service provided by PG&E …." (Section 4-G). This requirement is likely to be met by any credit-worthy ESP. Given, however, the potentially very large number of customers and amount of load served by the ESP, it may be this requirement will increase the insurance requirements of an ESP, a cost likely to be passed on to the CCA.

12.0 Description of Third Parties

- (INSERT LIST OF RFP RESPONDANTS OR ESP SUPPLIER IF UNDER CONTRACT WHEN THIS DOCUMENT IS SENT TO CPUC)

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Appendix to CPUC Submission Document:

Appendix A: Potential Third Party Suppliers List

INSERT CCSF CHOSEN SUPPLIER HERE
OR INSERT RFI, RFQ, AND OR RFP RESPONDENT LIST IF SUPPLIER NOT YET CHOSEN BY ORDINANCE

Including--

Company(ies), Summary, Rights and responsibilities, Technical and Operational Capabilities, Financial Highlights

Appendix B:

CCA Program Staffing and Budget

San Francisco CCA Start-up Budget Based on 2006-7 San Francisco City Budget Authorization			
	PD Budget	**SFPUC/SFE Budget**	**Total**
	$2,438,348	**$2,350,162**	**$4,788,510**

Task	**Program Director**	**SFPUC/SFE**	**Total**
Start Up Phase	-	-	-
Finalize IP	$95,004	$46,340	$141,344
Define R&R, MOU	$50,400	$4,456	$54,856
Define Metrics	$16,852	$2,350	$19,202
Financial Processes	$26,460	$8,772	$35,232
Engage Staff	$14,080	$8,913	$22,993
Program Plan	$97,224	$22,670	$119,894
Engagement Strategy	$31,916	$0	$31,916
CPUC Phase II	$26,460	$60,159	$86,619
Solar Ordinance	$95,760	$7,604	$103,364
Kick-Off	$79,380	$46,523	$125,903
Subtotal Start-Up	$533,536	$207,788	$741,324
Program Development Phase	-	-	-
Program Basis Report	$247,258	$135,017	$382,275
Remove Barriers	$38,934	$22,970	$61,904
Risk Analysis	$70,560	$47,997	$118,557
CCA Lessons Learned	$31,500	$8,003	$39,503
Hydro Options	$19,656	$158,666	$178,322
Low-Income Program	$8,316	$171,041	$179,357
Financing Plan & Model	$381,700	$38,978	$420,678
DB Integration	$141,120	$169,983	$311,103
PG&E Interface Plan	$191,520	$196,895	$388,415
CSC Analysis	$14,616	$117,358	$131,974
CSC Design	$30,240	$389,189	$419,429
Comm Plan	$93,240	$10,369	$103,609
360 Portfolio	$83,160	$106,610	$189,770
PG&E Tech Interface	$40,320	$170,732	$211,052
Siting, Permitting, Acquisition	$256,640	$242,380	$499,020
Regulatory Support	$54,432	$55,102	$109,534
Setup Rate Board	$20,160	$64,726	$84,886
Prepare RFI/RFQ	$181,440	$36,358	$217,798
Subtotal Program Development	$1,904,812	$2,142,374	$4,047,186
Total Start-Up Budget	**$2,438,348**	**$2,350,162**	**$4,788,510**
-	-	-	-

Appendix C:

PG&E Rate Schedule Information

(Source links to each schedule: PG&E http://www.pge.com/tariffs/rateinfo.shtml)

Residential

Residential Time-of-Use

Res. Baseline Territories and Quantities

Commercial/Gen. Svc. (A-1,A-6,A-10,E-19)

Commercial/Gen. Svc. (A-10 Only)

Industrial/Gen. Svc. (E-20)

Small Agricultural

Large Agricultural

Rates E36 and E37

Time-of-Use (TOU) Holidays

Appendix D:

PG&E CCA Tariffs

Tariff Name	PDF file icon PDF (KB)	WORD file icon DOC (KB)	Title
	7	35	Counties Served
E-1	37	206	Residential Services
E-3	63	562	Experimental Residential Critical Peak Pricing Service
EE	13	47	Service to Company Employees
EM	38	208	Master-Metered Multifamily Service
ES	38	220	Multifamily Service
ESR	37	212	Residential RV Park and Residential Marina Service
ET	38	224	Mobile Home Park Service
E-6	38	251	Residential Time-of-Use Service
E-7	39	246	Residential Time-of-Use Service
E-A7	38	233	Experimental Residential Alternate Peak Time-of-Use Service
E-8	30	156	Residential Seasonal Service Option
E-9	52	378	Experimental Residential Time-of-Use Service for Low Emission Vehicle Customers
EL-1	34	192	Residential CARE Program Service
EML	34	175	Master-Metered Multifamily CARE Program Service
ESL	40	239	Multifamily CARE Program Service
ESRL	39	212	Residential RV Park and Residential Marina CARE Program Service
ETL	39	229	Mobile Home Park CARE Program Service
EL-6	37	246	Residential CARE Program Time-of-Use Service
EL-7	38	199	Residential CARE Program Time-of-Use Service
EL-A7	37	181	Experimental Residential CARE Program Alternate Peak Time-of-Use Service
EL-8	27	116	Residential Seasonal CARE Program Service Option
E-FERA	25	104	Family Electric Rate Assistance
A-1	33	145	Small General Service
A-6	40	187	Small General Time-of-Use Service
A-10	58	357	Medium General Demand-Metered Service
A-15	22	111	Direct-Current General Service
E-19	75	386	Medium General Demand-Metered TOU Service
E-20	63	324	Service to Customers with Maximum Demands of 1000 Kw or More
E-31	25	90	Distribution Bypass Deferral Rate
E-37	51	251	Medium Gen Demand-Metered Time-of-Use Service to Oil & Gas Extraction Customers
ED	22	68	Experimental Economic Development Rate
E-CARE	23	50	CARE Program Service For Qualified Nonprofit Group-Living & Qualified Agricultural Employment Housing Facilities
LS-1	52	349	PG&E-Owned Street and Highway Lighting

LS-2	60	408	Customer-Owned Street and Highway Lighting
LS-3	33	149	Customer-Owned Street and Highway Lighting Electrolier Meter Rate
TC-1	30	128	Traffic Control Service
OL-1	37	188	Outdoor Area Lighting Service
S	74	349	Standby Service
E-DCG	54	188	Departing Customer Generation CG
E-DEPART	21	39	Departing Customers
E-LORMS	79	37	Limited Optional Remote Metering Service
E-RRB	27	52	Rate Reduction Bonds Bill Credit and Fixed Transition Amount
E-SDL	45	165	Split-Wheeling Departing Load
NEM	50	148	Net Energy Metering Service
NEMFC	33	104	Net Energy Metering Service for Fuel Cell Customer-Generators
NEMBIO	33	120	Net Energy Metering Service for Biogas Customer-Generator
E-ERA	27	274	Energy Rate Adjustments
AG-1	41	213	Agricultural Power
AG-R	49	260	Split-Week Time-of-Use Agricultural Power
AG-V	55	271	Short-Peak Time-of-Use Agricultural Power
AG-4	58	318	Time-of-Use Agricultural Power
AG-5	58	323	Large Time-of-Use Agricultural Power
AG-ICE	39	198	Agricultural Internal Combustion Engine Conversion Incentive Rate
E-CREDIT	52	478	Revenue Cycle Services Credits
E-DASR	80	45	Direct Access Services Request Fees
E-ESP	144	96	Services to Energy Services Providers
E-ESPNDS	86	45	Energy Service Provider Non-Discretionary Service Fees
E-EUS	100	70	End User Service
DA-CRS	19	55	Direct Access Cost Responsibility Surcharge
TBCC	35	243	Transitional Bundled Commodity Cost
E-CCA	44	89	Services to Community Choice Providers (Interim)
E-CCASR	21	41	Community Choice Aggregation Service Request Fees (Interim)
E-CCANDSF	21	40	Community Choice Provider Non-Discretionary Service Fees (Interim)
E-CCAEUS	21	40	End User Services (Interim)
CCA-CRS	15	41	Community Choice Aggregation Cost Responsibility Surcharge (Interim)
E-CCAINFO	36	71	Information Release to Community Choice Providers
E-BIP	38	132	Base Interruptible Program
E-OBMC	62	130	Optional Binding Mandatory Curtailment Plan
E-SLRP	62	109	Scheduled Load Reduction Program
E-DBP	49	187	Demand Bidding Program
E-POBMC	75	144	Pilot Optional Binding Mandatory Curtailment Plan
E-CPP	40	170	Critical Peak Pricing Program
EZ-20/20	41	82	California 20/20 Rebate Program
E-BEC	37	108	Business Energy Coalition
E-NF	53	219	Non-Firm Service
E-FFS	20	39	Franchise Fee Surcharge

Appendix E.

Local and State Law Compliance Matrix

ITEM	REQUIREMENT	STATUTE REFERENCE	IMP. PLAN SECTION
1	The process and consequences of aggregation	366.2(c)(3)	II, II-4.0, II-5.0, IV, V
2	An {*The appropriate scope and}* organizational structure of the program, its operations, and its funding.	366.2(c)(3)(A), SF Sec.3.A.1	II, IV, V
3	*City* ratesetting *mechanisms* and other costs to participants	366.2(c)(3)(B), SF Sec.3.A.2	II, IV, V
4	The benefits of the program to San Francisco customers	SF Sec.3.A.3	II, IV, V, V-4.2
5	How the program can meet or exceed the renewable portfolio standard required of PG&E under state law	SF Sec.3.A.4	II, IV, V
6	How the program can meet or exceed consumer protection standards required of PG&E by the CPUC including: {8 and 10 below}	SF Sec.3.A.5	II, IV, V, V-2.2
7	Provisions for disclosure and due process in setting rates and allocating costs among participants	366.2(c)(3)(C), SF Sec.3.A.5	V, V-2.4, V-4.2
8	The methods for entering and terminating agreements with other entities	366.2(c)(3)(D)	II, IV, V
9	The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures[2], credit issues, and shutoff procedures	366.2(c)(3)(E), SF Sec.3.A.5	IV, IV-4.0, V, V-4.2
10	Termination of the program	366.2(c)(3)(F), SF Sec.3.A.7	V, V-2.5, V-4.2
11	A description of the {*How the program will provide information about any*} third parties that will be supplying electricity *or providing other services* under the program, including, but not limited to, information about financial, technical, and operational capabilities	366.2(c)(3)(G), SF Sec.3.A.6	II, IV, V, V-4.2
12	What functions of the program should be performed by entities other than the City, including an Electric Service Provider (ESP) or its subcontractors	SF Sec.3.A.8	II, IV, V, V-2.4, V-2.5
13	Appropriate contract and bid requirements, including {items 15 through xx}:	SF Sec.3.A.9	II, IV, V

** Italics represent wording specific to the SF Ordinance when similar requirements appear in both the ordinance and AB117(requirements now reflected in the Public Utilities Code).*

2 *"Consumer protection procedures" not repeated in the SF Ordinance, covered in Items 6 and 7*

ITEM	REQUIREMENT	STATUTE REFERENCE	IMP. PLAN SECTION
14	Desired portfolio of resources that exceeds goals for energy efficiency, renewable energy, peak shaving and load management provided for in the City's adopted Electricity Resource Plan	SF Sec.3.A.9.I	**II, IV, V**
15	Recommended contract periods designed to optimize meeting Electricity Resource Plan goals and to provide reasonable repayment schedule for debt	SF Sec.3.A.9.II	II, II-4.3, IV, V
16	A requirement that bids include proposals for rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as, any capital, insurance and other costs associated with fulfilling the commitments made in its bid	SF Sec.3.A.9.III	II, II-4.3, IV, V, V-2, V-2.6, V-3.0
17	Recommended bid evaluation mechanisms that will encourage respondents to compete based on the environmental and local economic benefits of their proposed portfolio of energy resources	SF Sec.3.A.9.IV	V
18	Recommended contract provisions that will provide financial incentives to the City's Electric Service Provider, if one is selected, to accelerate deployment of and/or expand the energy efficiency and renewable energy components of its proposed energy portfolio	SF Sec.3.A.9.V	II, IV, V
OTHER ITEMS REQUIRED WITH IMPLEMENTATION PLAN			
19	Statement of intent (A) Universal access (B) Reliability (C) Equitable treatment of all classes of customers (D) Any requirements established by state law or by the CPUC concerning aggregated service	366.2(c)(4)	II, IV, V
20	A report on any CPUC or other developments that might impact the City's effort to proceed with implementation of a Community Choice Aggregation.	SF Sec.3.A	II, IV, V

Appendix F.
Current Electric Service Provider List

Potential Electrical Service Providers (ESP) Currently Registered in California

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
3 Phases Electrical Consulting 2100 SEPULVEDA BLVD, SUITE 15 MANHATTAN BEACH, CA 90266 ESP # 1350 Phone: (310) 798-5275 Fax: (310) 545-4218 E-mail: mmazur@3phases.com Officer: Michail Mazur, Founder and Chief Technical Officer	3 Phases Energy Services was founded in 1994. 3 Phases mission is to expand the frontiers of the renewable energy marketplace in the design of a sustainable energy future. It is a private company with approximately 8 employees. 3 Phases offers renewable energy nationwide, serving residential, nonprofit, corporate, and utility customers in every major city in the United States via a suite of renewable power generation facilities across the United States.[2,4]	In 2000, 3 Phases began offering direct access services to area residents and businesses under California's deregulation. 3 Phases expanded into wholesale and retail tradable renewable certificates (Green Certificates) and added a program to offer green pricing for investor and municipal-owned utilities. 3 Phases also has an onsite power division, specializing in solar photovoltaic and energy efficiency equipment. 3 Phases supports over forty landfill gas, biomass, geothermal, and solar generation facilities across the United States.[2]	3 Phases Energy Services has annual sales of approximately $5 million. [4]
American Utility Network (A.U.N.) 10705 DEER CANYON DRIVE ALTA LOMA, CA 91737 ESP # 1158 Phone: (909) 484-1858 Officer: Frank Annu N. Ziato, President	American Utility Network is a private company.	Not available	Not available
AOL Utility Corp. 12752 BARRETT LANE SANTA ANA, CA 92705 ESP # 1355 Phone: (714) 669-2743 Fax: (775) 406-3253 E-mail: lalehs101@hotmail.com	AOL Utility Corp. is a private company with approximately 7 employees. [4]	Not available	AOL Utility has annual sales of approximately $500 thousand. [4]

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
Officer: Paul Oshideri, President			
APS Energy Services Company, Inc. 400 E. VAN BUREN STREET SUITE 750 PHOENIX, AZ 85004 ESP # 1360 Phone: (602) 744-5364 Fax: (602) 744-5236 E-mail: sjenine.schenk@apses.com Officers: Vicki Sandler, President	APS Energy Services is the full-service energy services provider and competitive electricity subsidiary of Pinnacle West Capital Corporation, publicly held Arizona-based company. APS employs approximately 55 staff.[2]	APS Energy Services develops customized solutions to meet energy-related issues such as: energy master planning, energy supply consultation, provision of supply and simple billing, energy procurement, energy use consultation and facility audits, end-use operational solutions, state-of-the-art energy information tools, turn-key management and installation, and customized financing.[2]	APS has annual revenue of $226 million. Parent Company Pinnacle West Capital Corp has consolidated assets of approximately $9.5 billion and consolidated revenues of $2.8 billion.[2,4]
BP Energy Company 501 WESTLAKE PARK BLVD. HOUSTON, TX 77079 ESP # 1366 Phone: (281) 366-4627 Fax: (281) 366-2200 E-mail: prescorw@bp.com Officers: Tim Bullock, President Jim Dewar, Chief Financial Officer	BP Energy Company is a subsidiary of BP PLC. It has approximately 150 employees. BP PLC has four main businesses: Exploration and Production; Gas, Power and Renewables; Refining and Marketing, and Petrochemicals. The Gas, Power and Renewables group activities include marketing and trading of natural gas, natural gas liquid, new market development, liquefied natural gas, solar and renewables.[1,4]	BP's marketing and trading activities are focused on the deregulated natural gas and power markets of North America, the United Kingdom and certain parts of continental Europe. The Company's solar and renewables activities include the development, production and marketing of solar panels and the development of wind farms. BP Solar is one of the world's leading producers of photovoltaic solar cells with a 17% market share. In 2002 BP announced the start-up of a 22.5 megawatt wind farm in the Netherlands and the first commercial sale of green electricity into the Dutch national power grid. Other activities include gas-fired power generation projects.[1,2]	BP Energy has annual revenue of $226 million. For the fiscal year ended 12/31/04, parent company BP PLC revenues rose 23% to $285.06 billion. Net income rose 43% to $16.97 billion. [1,4]
Calpine PowerAmerica-CA, LLC 4160 DUBLIN BLVD. DUBLIN, CA 94568 ESP #1362 Phone: (925) 479-6600 Fax: (925) 479-7304 E-mail: curth@calpine.com	Calpine PowerAmerica is the retail energy service provider subsidiary of Calpine Corporation. Calpine Corp. is a North American power company engaged in the development, construction, ownership and operation of power generation facilities and the sale of electricity predominantly in the	As of December 31, 2003, Calpine Corp. owned interests in 87 power plants having a net capacity of 22,206 megawatts (MW). Of these projects, 68 were gas-fired power plants with a net capacity of 21,356 megawatts, and 19 were geothermal power generation facilities with a net capacity of 850	Calpine PowerAmerica has annual revenue of approximately $110 thousand. For the fiscal year ended 12/31/04, parent company Calpine Corp. revenues rose 4% to $9.23 billion. Net loss from

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
Officers: Curt Hildebrand Vice President of Marketing and Sales	United States, as well as in Canada and the United Kingdom. The Company focuses on two types of power generation technologies, natural gas-fired combustion turbine and geothermal. [1]	megawatts. Each of the power generation facilities in operation produces electricity for sale to a utility, other third-party end user or to an intermediary such as a trading company. The Company holds interests in geothermal leaseholds in Lake and Sonoma Counties in northern California (The Geysers). The Geysers produce steam that is supplied to geothermal power generation facilities owned by the Company for use in producing electricity. [1]	continuing operations and before acctng. change totaled $440.8 million vs. income of $86.1 million..[1,4]
City of Corona Department of Water & Power 730 CORPORATION YARD WAY CORONA, CA 92880 ESP # 1367 Phone: (951) 739-4967 Fax: (951) 735-3786 E-mail: georgeh.@ci.corona.ca.us	Not available	Not available	Not available
Constellation NewEnergy, Inc. 350 SOUTH GRAND AVENUE SUITE 2950 LOS ANGELES, CA 90071 ESP # 1359 Phone: (888) 526-0486 Fax: (213) 576-6070 E-mail: carol.schoenbachler@constellation.com Officers: Clem Palevich, President and Chief Executive Officer Kathleen Hyle, Chief Financial Officer	Constellation NewEnergy is the retail energy service provider subsidiary of Constellation Energy Group Inc. Constellation NewEnergy employs approximately 280 staff. Constellation Energy Group Inc. is a North American company, which includes a merchant energy business and the Baltimore Gas and Electric Company (BGE), a regulated electric and gas public utility in central Maryland. It has four operating segments: merchant energy, regulated electric, regulated gas and other nonregulated. Its merchant energy business is a provider of energy solutions. [1,4]	Constellation's merchant energy business serves the energy and capacity requirements (load-serving) of, and provides other energy products and risk-management services for various customers, such as utilities, municipalities, cooperatives, retail aggregators, and commercial and industrial customers. The Company's merchant energy business includes a generation operation that owns, operates and maintains fossil, nuclear and hydroelectric generating facilities, and interests in qualifying facilities, fuel processing facilities and power projects in the United States. Constellation NewEnergy, the Company's electric and gas retail operation, provides electricity,	Constellation NewEnergy annual Sales are approximately $77.2 million. For the fiscal year ended 12/31/04, parent company Constellation Energy Group revenues rose 30% to $12.55 billion. Net income from continuing operations and before acct. chg. rose 24% to $588.8 million. [1,4]

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
		natural gas, transportation and other energy services to commercial and industrial customers.[1]	
Coral Power, L.L.C. 4445 EASTGATE MALL, SUITE 100 SAN DIEGO, CA 92121 ESP # 1360360 Phone: (858) 320-1500 Fax: (858) 320-1550 E-mail: hharris@coral-energy.com Officers (Coral Energy Holding): Deborah Wernet, President Susan Hodge, Chief Financial Officer	The parent company to Coral Power, LLC is Coral Energy Holding, L.P. Coral Energy is an affiliate of the Royal Dutch / Shell group of companies. Coral Energy and its subsidiaries are an integral part of the Shell Trading network in North America, providing electricity, natural gas and risk management services. Coral Power Western Region operations and trading are headquartered in San Diego, California, with natural gas and electric marketing offices located in Oakland, California and Portland, Oregon. Shell Trading is a global business network integrating the worldwide energy trading activities of Shell. Operating as part of the Shell Trading network, Coral Energy's subsidiaries are among the top ten energy marketers in North America and the sole marketers of Shell's 7.5 trillion cubic feet of gas reserves in the US and Canada. [2]	Through it's relationship with Coral Energy and Shell Trading, Coral Power's capabilities include load forecasting, schedule coordination, wind power forecasting and scheduling, generation optimization, transmission and transportation management, risk management, long and short-term transaction structuring. The West Region maintains a 24-hour per day power trading and dispatch center in its San Diego office. Alliance relationships are in place with municipalities, as well as independent power producers. The West Region is currently moving over 6,500 MW/hrs of wholesale electric energy and 3.0 Bcf/day of natural gas in the WECC.[2]	Coral Power LLC's annual Sales are approximately $4.3 million. [4]
electricAmerica 600 ANTON BOULEVARD SUITE 2000 COSTA MESA, CA 92626 ESP # 1092 Phone: (714) 259-2508 Fax: (714) 259-2516 E-mail: igoodman@electric.com Officers (Commerce Energy Group): Peter Weigand, President Richard L. Boughrum, CFO and Senior Vice President	electricAmerica and Commonwealth Energy have combined with ACN Energy to become Commerce Energy. Commerce Energy started as a provider of residential energy service to customers in California, and now serves residential customers in six states. Commerce Energy is a subsidiary of Commerce Energy Group, a publicly held, diversified energy services company. Commerce Energy Group provides retail electric power to its residential, commercial, industrial	Commerce Energy predecessor company Commonwealth Energy Corporation began delivering electricity to California consumers in March of 1998 and grew to become the largest ESP in California, capturing over 60% of all switched accounts statewide.[2]	For the six months ended 01/31/05, Commerce Energy Group revenues rose 13% to $119.5 million. Net income totaled $252 thousand vs. a loss of $8.8 million.[1]

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
	and institutional customers and provides consulting and technology services to energy-related businesses and provides energy transaction data management services. Commerce Energy Group is a holding company that operates through its wholly owned operating subsidiaries.[1, 2]		
Energy America, LLC 263 TRESSER BLVD., ONE STAMFORD PLAZA 8TH FLOOR STAMFORD, CT 06901 ESP # 1341 Phone: (416) 590-3290 Fax: (416) 590-3632 E-mail: adrian.pye@na.centrica.com Officers: Lois Hedg-Peth, Chief Executive Officer Demi Tsioros, Vice President Finance	Energy America, along with Direct Energy, are subsidiaries of Centrica North America offering deregulated retail energy services in the United States.[2]	Centrica North America provides gas, electricity and related services to more than 1.5 million customers in Texas, Michigan, Ohio, Pennsylvania, Rhode Island, Connecticut and Massachusetts though its Direct Energy brand, and CPL Retail Energy and WTU Retail Energy brands in South and West Texas.[2]	Energy America has annual sales of approximately $9.2 million.[4]
Modesto Irrigation Dist. MID, MID Water & Power 1231 ELEVENTH STREET P.O. BOX 4060-95352 MODESTO, CA 95354 ESP # 1151 Phone: (209) 526-7560 Fax: (209) 526-7359 E-mail: ronm@mid.org Officers: Allen Short, General Manager	Modesto Irrigation District (MID) is a not-for-profit, state-owned organization formed by the government of Stanislaus County in 1887 to provide irrigation services in the area.[4]	In addition to water related services, the utility generates, transmits, and distributes electricity to more than 100,000 residential and business customers; markets wholesale power.[4]	MID has annual sales of approximately $216.6 million.[4]
New West Energy PO BOX 61868 MAILING STATION ISB 665 PHOENIX, AZ 85082-1868 ESP # 1063 Phone: (888) 639-9674 Fax: (602) 236-5443 E-mail: tmrabico@sprnet.com	According to their website, New West Energy is no longer offering service to customers in California.	Not available	Not available

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
Officers: Robert Nichols, Managing Director			
Pilot Power Group, Inc. 9320 CHESAPEAKE DRIVE, SUITE 112 SAN DIEGO, CA 92123 ESP # 1365 Phone: (858) 627-9577 Fax: (858) 627-9581 E-mail: tdarton@pilotpowergroup.com Officers: John Mellor, President	Pilot Power is a private company with approximately 7 employees. [4]	Not available	Pilot Power has annual sales of approximately $760 thousand.[4]
Quiet Energy 3311 VAN ALLEN PL. TOPANGA, CA 90290 ESP # 1368 Phone: (310) 656-9800 X211 Fax: (310) 656-9860 E-mail: mike@quietllc.com Officers: Mike Kasaba, President	Quiet Energy is a private company with approximately 3 employees. [4]	Quiet Energy is an Energy Service Provider serving large commercial and industrial users of electricity. They advocate the use of renewable energy, such as solar, wind, hydrogen, and biomass.[2]	Quiet Energy has annual sales of approximately $1 million[4]
Sempra Energy Solutions 101 ASH STREET, HQ09 SAN DIEGO, CA 92101-3017 ESP # 1364 Phone: (877) 273-6772 Fax: (619) 696-3103 E-mail: email@semprasolutions.com Officers: Keith Erbin, President	Sempra Energy is an energy services holding company operating through subsidiaries to develop energy infrastructure, operate utilities and provide related products and services to more than 29 million consumers in the United States, Europe, Canada, Mexico, South America and Asia. Regulated businesses operate under Sempra Utilities (Southern California Gas Company (SoCalGas) and San Diego Gas & Electric (SDG&E)). Sempra Global is the umbrella company for Sempra Commodities, Sempra Generation, Sempra Pipelines & Storage, and Sempra LNG and several smaller business units. Sempra Energy Solutions, the retail energy	Sempra Generation develops and operates merchant power plants and energy infrastructure for the competitive market. Its portfolio of generation assets total about 3,650 megawatts from three wholly owned facilities (two natural gas-fired and one coal-fired) and 50-percent ownership in seven facilities (six natural gas-fired and one coal-fired). The electricity generated by these plants is sold to the wholesale market and retail electricity providers, such as utilities, marketers and large energy users. Sempra Commodities provides worldwide marketing and risk-management services to wholesale customers for natural gas, power, petroleum products and base metals.[2]	For the fiscal year ended 12/31/04, Sempra Energy revenues increased 19% to $9.41 billion. Net income from continuing operations before accounting change rose 32% to $920 million.[1]

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
	marketing and services unit, was restructured in early 2005 amidst a larger company reorganization and its operations now reside under the Sempra Generation and Sempra Commodities units. [1,4]		
Strategic Energy, L.L.C. 7220 AVENIDA ENCINAS, SUITE 120 CARLSBAD, CA 92009 ESP # 1351 Phone: (888) 925-9115 Fax: (412) 258-4866 E-mail: customerrelations@sel.com Officers: Shahid Malik, President and CEO Andrew J. Washburn, CFO	Strategic Energy is a competitive supplier of retail electricity operating in ten states with deregulated energy markets, including California, Connecticut, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas. Strategic employs more than 275 full-time energy professionals. It is a subsidiary of Great Plains Energy, a publicly traded company. In addition to Strategic Energy, Great Plains operates a regulated utility, Kansas City Power & Light (KCP&L).[2]	Strategic Energy began serving retail electricity customers in 1997 as a participant in Pennsylvania's Pilot Program. They began serving Massachusetts, California and New York in 2000, Ohio in 2001, Texas in 2002, New Jersey and Michigan in 2003 and Connecticut and Maryland in 2004. Strategic now serves more than 7,000 commercial, institutional and industrial customers in states that have enacted retail choice. [2]	Strategic Energy's 2004 revenues totaled approximately $1.4 billion[2]

1 *source: Reuters, Yahoo Finance*
2 *source: Company Website*
3 *source: Company Fact Sheet*
4 *source: Hoover's Online*

Potential Electrical Service Providers (ESP) Currently Serving Customers in Other CCA States (Not Currently Registered in CA*)

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
FirstEnergy Solutions 395 Ghent Road Akron, Ohio 44333 Phone: (800) 736-3402 Fax: (330) 384-3772 **Officers (FirstEnergy Corp):** Anthony Alexander President, Chief Executive Officer, Director Richard Marsh Chief Financial Officer, Senior Vice President	FirstEnergy Corp. (FirstEnergy) is a public utility holding company that provides regulated energy services. The Company has eight principal electric utility operating subsidiaries: Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company, American Transmission Systems, Inc., Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company. FirstEnergy's other principal subsidiaries are FirstEnergy Solutions Corp. (unregulated), FirstEnergy Facilities Services Group, LLC, MYR Group, Inc. and First Communications, LLC.[1]	FirstEnergy Corp. operates 20 power plants with a total system capacity of more than 13,000 megawatts. Altogether, the Company produces nearly 70 million megawatt hours of electricity each year to meet its customers' needs. FirstEnergy Solutions, an unregulated subsidiary of FirstEnergy Corp., offers a wide range of energy and related products and services, including the generation and sale of electricity; exploration, production and sale of natural gas; mechanical and electrical contracting and construction; and energy management. FirstEnergy Solutions is a licensed electric supplier in Ohio, Pennsylvania, New Jersey, Delaware, Maryland, Michigan and Washington, D.C. [2]	For the fiscal year ended 12/31/04, First Energy Corp. revenues rose 7% to $12.45 billion. Net income from continuing operations and before accounting change rose from $424.2 million to $873.8 million.[1]
Allegheny Power 800 Cabin Hill Drive Greensburg, Pa. 15601-1689 Phone: (724) 837-3000 Fax: (301) 665-2736 **Officers (Allegheny Energy, Inc.):** Paul Evanson Chairman, President, Chief Executive Officer Jeffrey Serkes Chief Financial Officer, Senior Vice President	Allegheny Energy, Inc. (AE) is a diversified utility holding company that operates in the core businesses of electricity generation, and transmission and distribution, primarily through direct and indirect subsidiaries. The Company is an integrated energy business that owns and operates electric generation facilities and delivers electric and natural gas services to customers in Pennsylvania, West Virginia, Maryland, Virginia and Ohio. Allegheny has two business segments: the Delivery and Services segment that includes Allegheny's electric and natural gas transmission and distribution (T&D) operations, and the Generation and	Allegheny Power is the energy delivery business of Allegheny Energy, delivering electricity and natural gas to about three and one-half million people in parts of Maryland, Ohio, Pennsylvania, Virginia, and West Virginia[2]	For the fiscal year ended 12/31/04, Allegheny Energy Inc. revenues rose 26% to $2.76 billion. Net income from continuing operations before acct. change totaled $129.7 million, vs. a loss of $308.9 million. [1]

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
	Marketing segment, which includes Allegheny's power generation operations. [1]		
American Electric Power **1 Riverside Plaza** **Columbus, OH 43215-2373** Phone: (614) 716-1000 Fax: (614) 223-1823 **Officers:** Michael Morris, Chairman, President, Chief Executive Officer Susan Tomasky Chief Financial Officer, Executive Vice President of AEP and of AEPSC	American Electric Power Company, Inc. (AEP) is a registered public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries. The public utility subsidiaries of AEP are American Electric Power Company, Inc., AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. [1]	American Electric Power owns more than 36,000 megawatts of generating capacity in the United States and is the nation's largest electricity generator. AEP is also one of the largest electric utilities in the United States, with more than 5 million customers linked to AEP's 11-state electricity transmission and distribution grid. The company owns two wind generation facilities totaling 310 megawatts of generating capacity, and is involved with another company in a third project[2]	For the fiscal year ended 12/31/04, revenues decreased 4% to $14.06 billion. Net income from continuing operations and before extraordinary items and acct. change totaled $1.13 billion, up from $522 million. [1]
Cinergy Corp **1139 East Fourth Street** **Cincinnati, OH 45202** Phone: (513) 421-9500 Fax: (513) 651-9196 **Officers:** James Rogers Chairman, Pres, Chief Executive Officer James Turner Chief Financial Officer, Executive Vice President	Cinergy Corp. is a utility holding company that owns all outstanding common stock of The Cincinnati Gas & Electric Company (CG&E) and PSI Energy, Inc. (PSI). The Company's other subsidiaries are Cinergy Services, Inc. (Services), Cinergy Investments, Inc. (Investments) and Cinergy Wholesale Energy, Inc. (Wholesale Energy). The Company conducts operations through its subsidiaries and manages its businesses through its three segments: Commercial Business Unit; Regulated Businesses Business Unit (Regulated Businesses), and Power Technology and Infrastructure Services Business Unit (Power Technology). [1]	Cinergy commercial businesses manage, operate and/or maintain our generation, and the marketing and trading of energy commodities, primarily natural gas and electricity. The marketing and trading of energy commodities includes energy risk management activities and customized energy solutions. Cinergy commercial businesses operate 13,331 megawatts of generating capacity, own and/or operate 19 cogeneration projects with over 1,200 megawatts of generating capacity, marketed and traded 147.5 million megawatt-hours of over-the-counter contracts for the purchase and sale of electricity in 2003. Electricity generation	For the fiscal year ended 12/31/04, Cinergy Corp. revenues rose 6% to $4.69 billion. Net income from continuing operations and before accounting change fell 8% to $400.9 million. [1]

COMPANY	SUMMARY	TECHNICAL AND OPERATIONAL CAPABILITIES	FINANCIAL HIGHLIGHTS
		including operation of coal, gas, cogeneration and renewable power plants. [3]	
DPL Inc **1065 Woodman Drive** **Dayton, OH 45432** Phone: (513) 421-9500 Fax: (513) 651-9196 **Officers:** James Mahoney Pres, Chief Executive Officer, Director John Gillen Senior Vice President and Chief Financial Officer DPL Inc. and DP&L	DPL Inc. (DPL) is a diversified regional energy company whose primary business is comprised of the activities of its subsidiary, The Dayton Power and Light Company (DP&L). DP&L is a public utility engaged in the sale, transmission and distribution of electricity to residential, commercial, industrial and governmental customers in a 6,000-square-mile area in West Central Ohio. Electricity for DP&L's 24-county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. DP&L also purchases retail peak load requirements from DPL Energy LLC (DPLE), another subsidiary of the Company. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense. DP&L sells any excess energy and capacity into the wholesale market. [1]	DPL Energy is a diversified regional energy business, operating both coal fired generation capacity and natural gas fired peaking units. Capacity not sold to DP&L is marketed on a wholesale basis throughout the eastern United States. [2]	For the fiscal year ended 12/31/04, DPL Inc. revenues rose less than 1% to $1.2 billion. Net income before acct. change rose 65% to $217.3M. [1]

** These organizations are potential new entrants to the California market either by registering as ESPs or as teaming partners to registered ESPs*

[1] *source: Reuters, Yahoo Finance*

[2] *source: Company Website*

[3] *source: Company Fact Sheet*

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Appendix G
H Bond Authority

SAN FRANCISCO CHARTER; SECTION 9.107.8: REVENUE BONDS.

The Board of Supervisors is hereby authorized to provide for the issuance of revenue bonds. Revenue bonds shall be issued only with the assent of a majority of the voters upon any proposition for the issuance of revenue bonds, except that no voter approval shall be required with respect to revenue bonds:

Issued to finance or refinance the acquisition, construction, installation, equipping, improvement or rehabilitation of equipment or facilities for renewable energy and energy conservation.

Except as expressly provided in this Charter, all revenue bonds may be issued and sold in accordance with state law, or any procedure provided for by ordinance.

(Amended November 2001)

Appendix H.
Low-Income Customers.

Treatment of Low-Income Customers Requires Special Consideration.

A key aspect of residential rates regulated by the CPUC is the California Alternative Rates for Energy program (CARE). This program applies to residential customers of PG&E and other investor-owned utilities and provides about a 40% discount from average total residential bills for customers with incomes up to 175% of the Federal poverty line. In CCSF about 17% of residential customers are currently *participating* in CARE.[8] This is slightly lower than the 21% of PG&E's residential customers that are participating in CARE system-wide. Moreover, according to PG&E the CARE program has a higher penetration rate in San Francisco (82%) than it does on average throughout PG&E's system (70%). This means that there are fewer customers eligible for CARE and not participating in the program in San Francisco than in the rest of PG&E's service territory. Within CCSF these customers currently have average monthly bills of $26.27 of which $8.79, or 33% is constituted by the generation portion. Based on CPUC Decision 05-12-041 the City anticipates that CARE program funds will be made available to CCA CARE eligible customers such that these customers should be no worse off under the CCA program than under PG&E rates.

Appendix I:
Private Purchases of PV Systems

Example 1: A large commercial customer with sufficient tax liability purchases a photovoltaic system of 100 kilowatts. On the open market such a system might cost $8.50 per watt (ac), but CCA bulk purchase of several megawatts reduces the cost to $7.00per watt (ac), saving the customer $150,000 on the purchase price.

A California Solar Initiative (CSI) program rebate pays $2.00 per watt, worth $200,000 for a 100 kilowatt system. Next, the CCA contributes $2.00 per watt, or $200,000, to the customer from money received through the sale of 15 to 20 year Solar H-Bonds as an equity position in the photovoltaic system.

Over a ten year period the customer takes the available solar tax credits and accelerated depreciation on their share of the photovoltaic system. Under the tax regime projected after 2007 the tax credit is 10 percent of the total customer owned share of the installed cost of the photovoltaic system. The installed cost, as stated above, is assumed here to be $750,000 with the CCA owning a $200,000 share. Thus the initial customer ownership share is $550,000, and the first year tax credit would be 10 percent of this amount or $55,000. In addition, the customer gets to take a 5-year accelerated depreciation on their ownership share. Assuming a federal tax rate of 33 percent, the tax write-off would be worth another $150,000.

Approximate Schematic Financial Summary for CCA/Private Partnership

Normal Purchase Cost	$850,000
CCA Bulk Purchase Saving	- $150,000
California Rebate	- $200,000
CCA Share	- $150,000
Tax Benefits	- $200,000
Net Cost to Customer	$150,000

The CCA share could be for ownership rights of valuable rights including a portion of future electric generation, renewable credits, carbon credits, emergency access, and option for later system purchase or transfer of ownership.

Example 2: If the commercial tax credit remains at 30 percent after 2008 then the value equation will shift significantly, with the Tax Benefit increasing from $200,000 to about $300,000.

Approximate Schematic Financial Summary for CCA/Private Partnership

Normal Purchase Cost	$850,000
CCA Bulk Purchase Saving	- $150,000
California Rebate	- $200,000
CCA Share	- $100,000
Tax Benefits	- $300,000
Net Cost to Customer	$100,000

Example 3. The CCA elects to build and finance a photovoltaic system using Solar H-Bonds, but with customer participation. The system is installed on or near a customer's site and a software system determines the value of the electricity against the customer's bill. The CCA does not sell electricity to the customer, but leases the system with the option to buy out the City's interest at the end of the lease. Excess electricity not used on site could be sold to other CCA customers at peak price value. The system is assumed to be eligible for CSI rebate funding because it is being utilized primarily by individual customers and not the general CCA. As in example 2, a program focused on lease agreements is greatly facilitated by low cost installations, particularly since tax credits are not available in this case. Assuming an installed cost of $7.25 per watt, and a rebate of $2.25 per watt, means a net customer cost of $5.00 per watt. Part of the installed cost might be placed on a 10 year tax-free bond at 5 percent interest and part on a longer term bond.

Example 4. The CCA elects to have a third party own, install and operate a photovoltaic system and lease the PV system, or sell the electricity, for a period up to 10 years, after which option of ownership would be offered to a customer or the CCA. The third party receives all benefits of rebates, renewable certificates and tax credit.

Appendix J:
Program Risk Analysis

The primary risk associated with the CCA program is start-up risk. CCSF shall use general funds to get the program funded and staffed to do the many tasks described here that are supposed to occur prior to the issuance of an RFP. Under this program, CCSF will not assume any risk or enter into any binding commitment to assume responsibility for service and resource adequacy requirements for participating customers until after an RFP has been issued to suppliers. Thus, while this Implementation Plan does not incur any liability until it has collected further information from the energy industry, there is some risk of not getting a successful set of bids from prospective suppliers, and thus not recouping the initial City investment in the program.

The San Francisco CCA Program involves complexity and a number of intergovernmental and business participants. Accordingly, the program needs to be well organized and efficient to ensure that all potential issues are identified well in advance, and addressed in a timely fashion. This effort is one of the key elements in successfully eliminating or mitigating complex program risks. Said another way, in a complex program environment, the application of early proactive efforts to issue identification and resolution should reduce the quantity of problems ultimately faced by the program.

One of the most significant success factors for the CCA Program will be how effectively and fairly risk is allocated between the CCA Program and the supplier, especially for the renewable power generation elements. The CCA Program will need to complete the risk assessment and allocation process prior to finalizing the RFP documents and the supplier contract terms agreed.

For the CCA Program, there are a range of risk areas that track the program phases. During the Program Development phase, the CCA Program will face risks relating to the process of completing the 'checklist' of necessary steps required to get the program to the point where an RFP for the supplier can be issued. As the implementation phase proceeds, the risks will shift to include the range of risks common to large scale infrastructure projects.

The approach to managing these risks is for the CCA Program staff to identify the risks inherent in each of its activities across the phases of the program, and then to develop effective strategies to eliminate, mitigate or allocate these risks between the CCA Program, the supplier and possibly other stakeholders if appropriate.

It is often tempting for an owner to allocate as much risk as possible to a contractor for various reasons, especially in a performance driven, turnkey or Design, Build, Operate, Maintain (DBOM) contracting arrangement. However, there are two main disadvantages to this approach; the likelihood of excessive bid price contingency and a higher likelihood of conflict and claims as the project advances.

Effective risk allocation is the process of determining which party can best manage a given risk by virtue of its strengths and resources. A review of the costs and impacts that may be associated with the risk can be an effective method to test the choice of a party to manage a given risk. If having that party manage the risk is projected to be the most effective in reducing impact, and containing costs, this confirms that the right party has been selected to manage the risk.

In order to facilitate the timely rollout of the 360 MW according to the CCA-supplier agreement, CCSF must take responsibility for removing permitting and zoning barriers to non-polluting facilities. If the City permitting process proves far slower than assumed in the contractually agreed-upon roll-out the City shall exempt the supplier for non-performance penalties associated with those deadlines for which the City failed to provide permits.

Supplier rollout delays associated with PG&E Interconnect delays shall also be exempt from non-performance penalties.

There are three steps that can be used to guide the risk allocation process. The first is to identify the nature of the expected project risks, and determine whether they are 'known' or 'unknown' risks (discussed in further detail below), the second is to assess the relative capabilities of the CCA Program and the supplier to manage or mitigate each of the risks. The third is to determine if risk should be assigned to the CCA Program, the supplier, a third party stakeholder, or shared. If shared, this step includes developing the criteria for sharing the risk.

This plan proposes that a supplier perform a majority of the wholesale electricity business functions required to operate the CCA. For example, the supplier should assume responsibility for daily power operations: scheduling power and settlement with the California ISO. That responsibility will extend to resource procurement risk management and credit management with generators, though the level of that responsibility may be affected by decisions around municipal power plant ownership. The wholesale power responsibilities of the supplier should be guided by resource planning direction provided by the CCA both in the RFP and as necessary with additional interaction with the supplier.

Risk Identification

The CCA will first complete a categorical identification of the significant risk factors that will be or are expected to be present as the project is advanced. Once the specific risks have all been identified, the nature of the risks will be determined. A key determinant is whether a risk is 'known' or 'unknown'.

Determining the Nature of the Risks

A 'known' risk is one where the supplier would be in a good position to understand the nature and extent of the risk, and to identify the possible range of its cost impact. A 'known' risk on a lump sum infrastructure project could be a quantity risk taken by the contractor, where the exact quantity of a certain item cannot be determined until construction is in progress, but the upper and lower ranges of required quantities it is predictable. The allocation of this sort of risk to the contractor is commonly used for many lower cost elements of an infrastructure project, such as routine electrical system or plumbing components.

By contrast, an unknown risk is one where the Contractor must accept responsibility for elements of a project without having complete information. For example, requiring a contractor to excavate a number of sites to build foundations without telling the contractor anything about the ground conditions, or allowing the contractor to perform their own site evaluation presents the contractor with an unknown risk. As should be obvious form this example, this is not an ideal approach, because the contractor will have to include 'worst case' costs in its bid price.

Allocating the Risks

Once the risks have been identified, the next determination is of whether the CCA Program or the supplier will be in a better primary position to manage each risk as the project proceeds. Generally, those risks that are more toward the 'known' end of the scale, have potentially smaller proportional cost impact relative to the bid price and will be more closely related the supplier's scope of work are better managed by the supplier.

By contrast, the management of the ongoing cooperation required from city agencies is an area where the implementing agency, not the contractor, is in the better position. Accordingly, this is typically the implementing agency's responsibility. Some further examples of risks that are typically allocated to the contractor and the agency in a turnkey project are shown in the following table:

CONTRACTOR	AGENCY
Final design/functionality Quantity risk to achieve functionality Longer term quality (if DBOM) Schedule/completion Time Cost (inflation/currency) Procurement Coordination	Providing access and cooperation at all project site locations on time Input/changes from Service Providers Community/political input Force Majeure events Changed site conditions Changes in regulations

Risk Sharing

Many project risks are predictable and incremental. This means that if the most likely predicted outcome for a risk element is given an arbitrary value of 100%, it is more likely that the actual experience will be a result closer to the predicted 100% than a result that varies widely from the predicted outcome. Accordingly, an owner can reduce ultimate costs by taking the responsibility for less likely, worst case scenarios.

As certain incremental risks can have significant costs, the CCA Program may benefit from a risk sharing approach for some elements of the renewable infrastructure risks to prevent excessive contingency pricing. A typical risk sharing structure for incremental risks is to include a set of tiers in the contract pricing structure. The first tier is the lump sum price; up to a certain threshold, all costs associated with this element of risk are the contractor's responsibility. Above the first threshold, there can be some shared tiers where contractor and the agency are each responsible for set percentages of the costs, and then the CCA Program would take full responsibility at the higher threshold level, which has a lower probability of being reached.

The selection of the actual thresholds and percentage amounts is critical in whether or not this approach will succeed on any given project. The first challenge is to make sure that it ends up functioning as a risk mitigation structure, and not as a bonus pool for the contractor. The key to this is to ensure that the supplier bears more of the initial risk through the tiers, with the CCA Program's responsibilities phasing in at the higher end, to 'cap' the risk. The idea is to structure a hurdle of supplier risk between the lump sum price and the tier(s) where the CCA Program pays most of the costs.

In conclusion on risk allocation, effective analysis of the potential risk factors, and strategic allocation based on the best approach to managing the risk should allow the supplier bidders to more accurately assess the amount of contingency funding to include in their pricing for the risks they will be assigned under the contract. Once the allocation has been determined, it is important for the CCA to work closely with the supplier bidders to make sure that they understand both the extent of the risks that they will be responsible for, and any limitations on this risk that will work to protect them. This communication process is beneficial, because when contractors fully understand the risks they will be responsible for, they are less likely to assert claims based on incorrect or incomplete understandings of these risks as the project proceeds.

Appendix K
Consequences for Ratepayer Risk

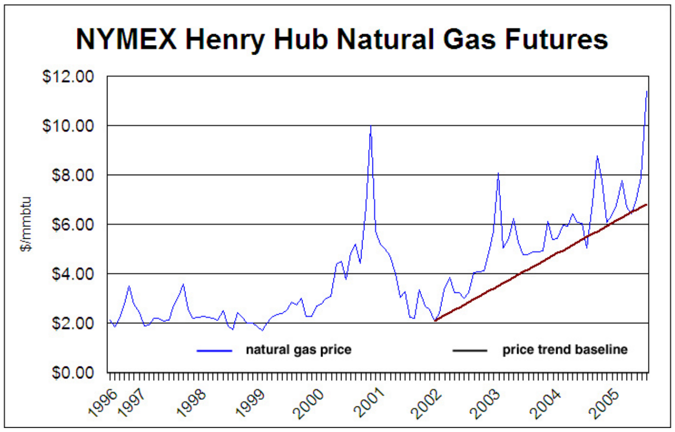
The procurement risk for CCA ratepayers will be unchanged or improved in the short term and reduced in the long term. By transferring from PG&E to the San Francisco CCA, ratepayers will change from a service whose rates are decided twice a year by state regulators to a service whose rates are fixed according to a mutually agreed upon multi-year schedule, and based on competitive rates. CCA customers' rates will be established by the RFP process and ratepayers will have the opportunity to compare the old service to the new and have four opportunities to opt out of the program without penalty. CCA customers will not be charged more than PG&E equivalent generation rates, including the Customer Responsibility Surcharge (CRS), when they are transferred to the new service, and any changes in rates will be according to a predictable mutually-agreed upon multi-year schedule, rather than on the biannual operating costs of the service provider, as with PG&E – this is a major rate stabilization and risk reduction mechanism in addition to being greener, at competitive rates. Risks to the city itself will be partly handled by bonding, insurance and letter of credit requirements for the supplier.

Exposure to PG&E procurement costs will remain unaltered at first but decline to zero over time. The customers are covered by the CPUC decisions establishing a CRS, which is a non-bypassable fee to cover ongoing utility procurement costs to avoid cost-shifting between customers. As CCA Customers, San Francisco Ratepayers will not escape payment of the CRS, but departing from PG&E procurement will circumscribe CCA ratepayer risk and terminate further "New World" risks now being born by PG&E in its procurement and power plant development projects.

Managing Natural Gas Risk

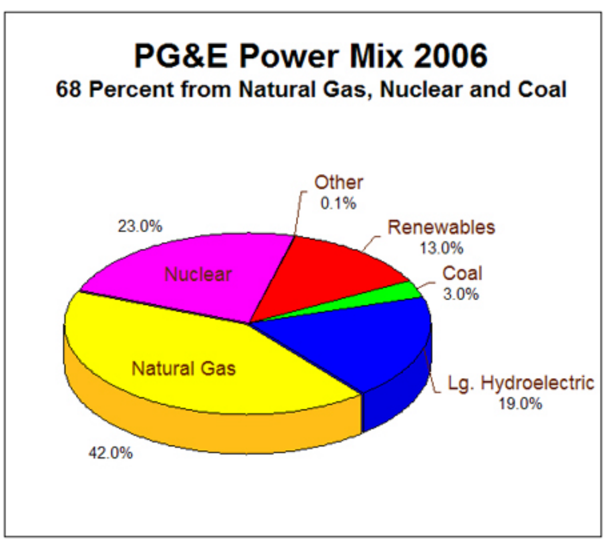
Exposure to wholesale power prices will also decline as CCA-owned facilities are developed and reliance on volatile generation fuel cost is reduced in the portfolio. The avoided risk has several components. First, there is an underlying trend toward increased fuel costs for natural gas, which began in 2002.

[Exhibit II-3: Natural Gas Futures (Source: NYMEX, 2006)]



Nationally, the use of natural gas for the generation of electricity plays a fairly minor role in determining customer electricity prices. This is because only 17 percent of US electricity is produced using natural gas. California is much more dependent on natural gas, for 37 percent of its electricity supply, while PG&E gets fully 42 percent of its electricity from natural gas, and is now seeking CPUC and CEC approval to invest $1.5 Billion in thousands of MW of new gas-fired power plants. This places PG&E customers in an extraordinarily vulnerable position.

[Exhibit II-4: PG&E Power Mix (PG&E, 2006)]

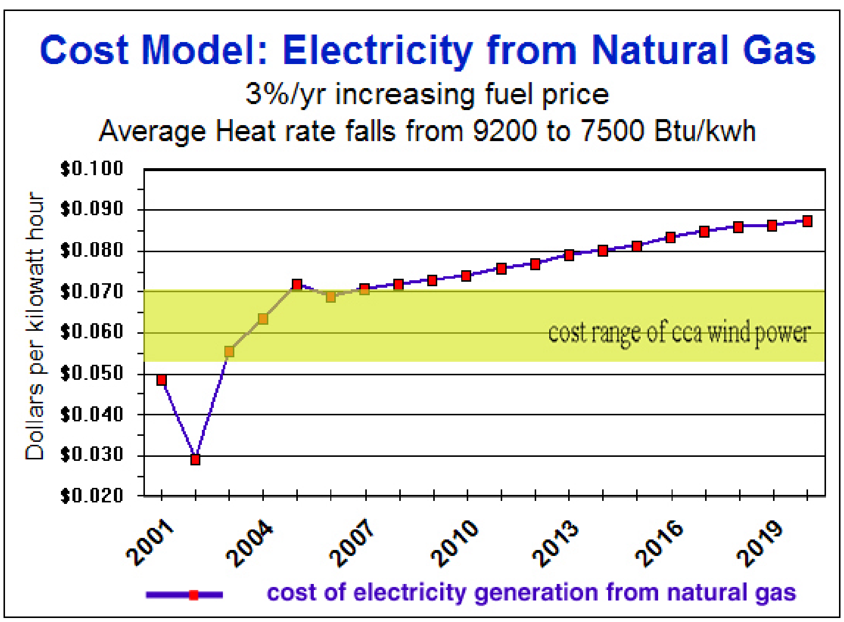


The effect of current and future gas prices on electricity depends heaving on the efficiency of the generation capacity, which is known the term “heat rate”. Heat rate is measured in British Thermal Units (BTU) of fuel energy input required to produce one kilowatt hour of electricity output. The normal market conversion from cost of natural gas to cost of electricity was given by the California Energy Commission in the 2005 Integrated Energy Policy Report:

> “at a gas price of $6, the fuel cost to produce one MWh from a plant with a heat rate of 11,000 British thermal units (Btu) per kilowatt hour (kWh) would be $66, compared with $42 from a plant with a heat rate of 7,000 Btu per kWh. At a $9 gas price, the comparison is $99 to $63.” *California Energy Commission, 2005 IEPR, p. 60.*

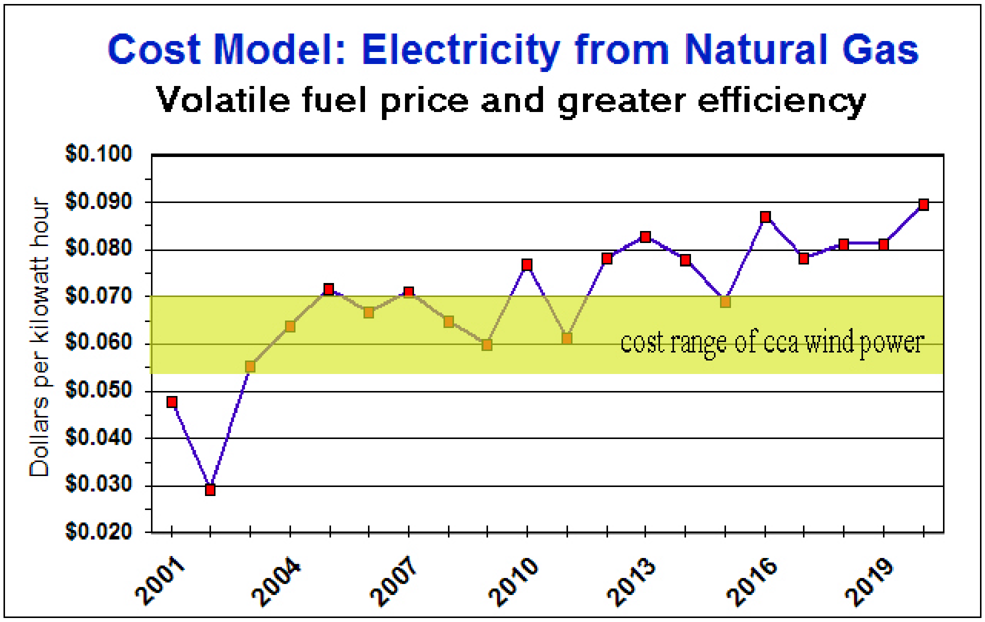
This fuel cost, when gas costs $6 per million Btu, represents about 80 percent of the delivered cost of electricity. Thus, the efficient plant generates electricity at an average cost of 5.3 cents per kilowatt-hour, while the inefficient plant would cost as much as 7.7 cents per kilowatt-hour. This chart, which might be considered a “high but not worst case scenario”, shows the projected average cost of electricity in California if natural gas prices and efficiency of power plants both continue to rise gradually from current (2006) levels. In this scenario, by the middle of the next decade almost all renewables will be cheaper than natural gas, as wind energy is today.

[Exhibit II-5: Cost Model prepared by Local Power based on NYMEX Futures Prices 2006 and California Energy Commission 2005]



In recent history natural gas prices have not risen in a linear fashion, rather they tend to be quite volatile. The following chart shows a model of what might happen if this continues.

[Exhibit II-6: Cost Model prepared by Local Power based on NYMEX Futures Prices 2006 and California Energy Commission 2005]



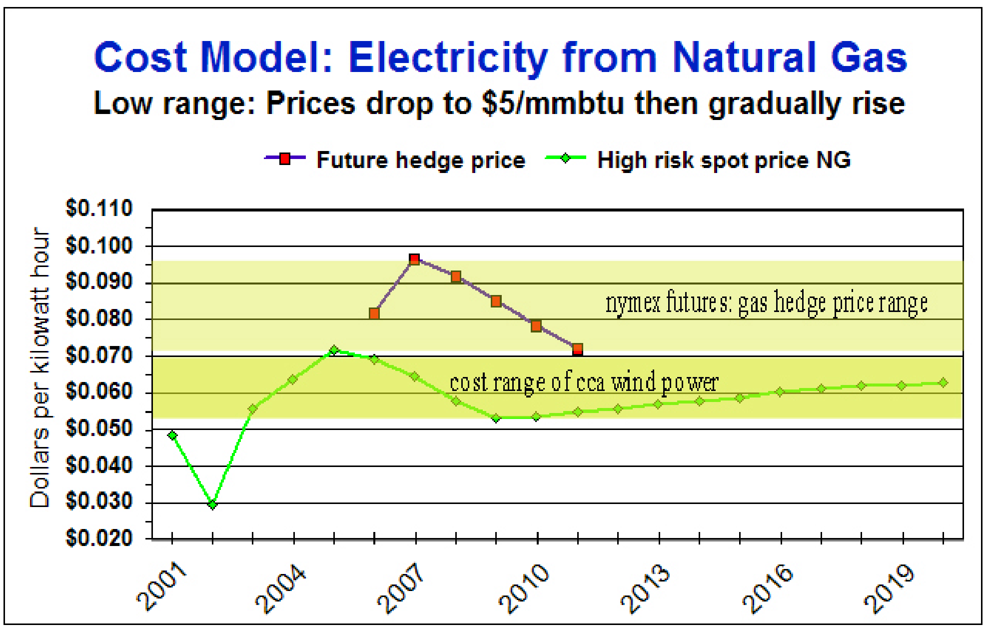
Many analyses predict generally lower natural gas costs than what is assumed above. It should be noted that such low-end predictions have been almost invariably incorrect since the beginning of the decade. Nevertheless it is important to take such possibilities seriously, especially due to the highly volatile and unpredictable nature of natural gas prices.

A recent report by the authoritative American Gas Foundation (Natural Gas Outlook to 2020, Feb. 2005) painted three scenarios, which were largely based on policy decisions. The lowest price case, called the "expanded scenario", suggested natural gas averaging $5.50/mmbtu until 2020. The authors of the study argued that accomplishing this required ALL of the following: dramatic expansion of LNG imports, construction of the Alaska pipeline, removing all restriction to offshore drilling on the East Coast and the Gulf of Mexico, opening up significantly more access in the Rocky Mountain region, and greatly limiting the development of new gas power plants.

The next scenario show the effect of a significant drop from current natural gas prices for next two years, along the lines of the AGA "expanded scenario", followed by a slow steady increase into the next decade. This is the most optimistic scenario. While such prices may make natural gas look attractive, the recent high prices and volatility make it likely that the greater risk is on the upside. This is reflected in the NYMEX natural gas futures market, which allows a power plant to hedge against large upward price swings over the next five years. There is a substantial cost premium required to do this, particularly if one assumes lower costs in the next few years compared to now.

The upper line and shaded area shows the cost and range to insure future natural gas prices when translated into electricity prices, which ranges between 7.1 and 9.6 cents per kilowatt-hour. This is contrasted to the lower shaded area where a price hedge is purchased through the CCA's 150 megawatt wind farm. Note that this insurance, which costs between 5.3 and 7 cents per kilowatt-hour, extends out at least 20 years, compared to hedges for gas futures which only protect out to 5 years.

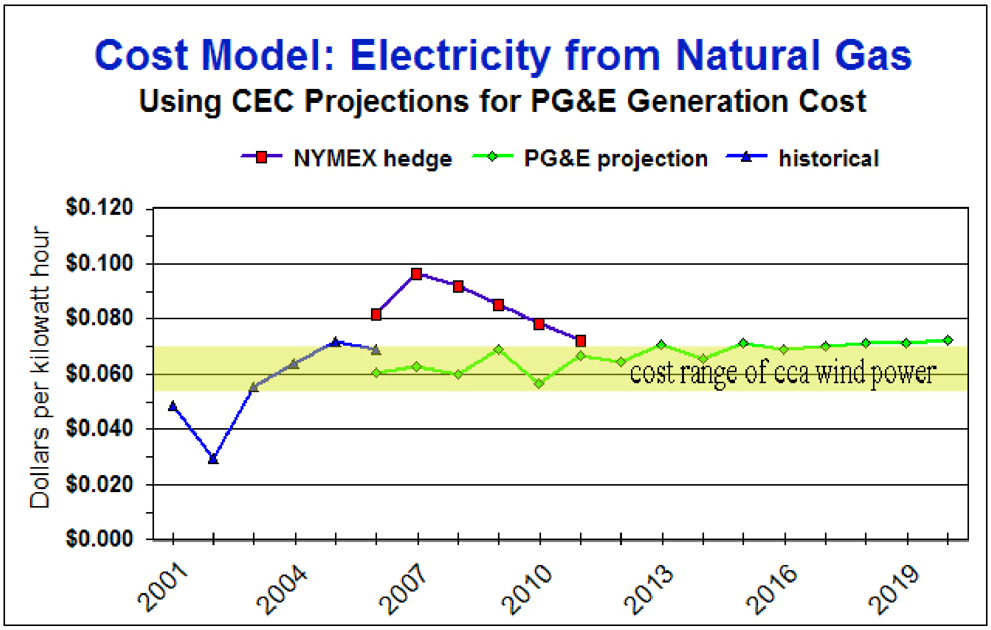
[Exhibit II-7: Cost Model prepared by Local Power based on NYMEX Futures Prices 2006 and California Energy Commission 2005]



The cost premium for natural gas hedge over a wind hedge averages about 2.5 cents per kilowatt-hour. A 150 megawatt wind farm operating at a 33 percent capacity factor will generate 438,000 megawatt-hours per year and currently would save ratepayers about $25 per megawatt hour as a gas hedge, or $10.9 million per year. At this rate, the hedge value alone would easily repay the full capital cost of the wind farm over a 20 year lifecycle.

The last scenario is based on the California Energy Commission's projections for the cost of natural gas for PG&E's electric generation. The projection was developed in a supplement to the 2005 IEPR (Revised Reference Case in Support of the 2005 Natural Gas Market Assessment, Staff Report, September 2005; CEC-600-2005-026-REV, p.48.), and it reflects significant volatility and generally increasing costs out to 2016. The graph shows PG&E's natural gas cost to be the highest among the state's different utilities. This amplifies the effect of PG&E's already larger than average exposure to natural gas generation. It should be pointed out that the projections were made just prior the catastrophic events in the Gulf of Mexico, and thus significantly understated the impact on current prices in 2006. This is reflected in the chart below. The CEC projections also broadly support the value estimates above for the hedge benefits of wind power.

[Exhibit II-8: Cost Model prepared by Local Power based on NYMEX Futures Prices 2006 and California Energy Commission 2005]



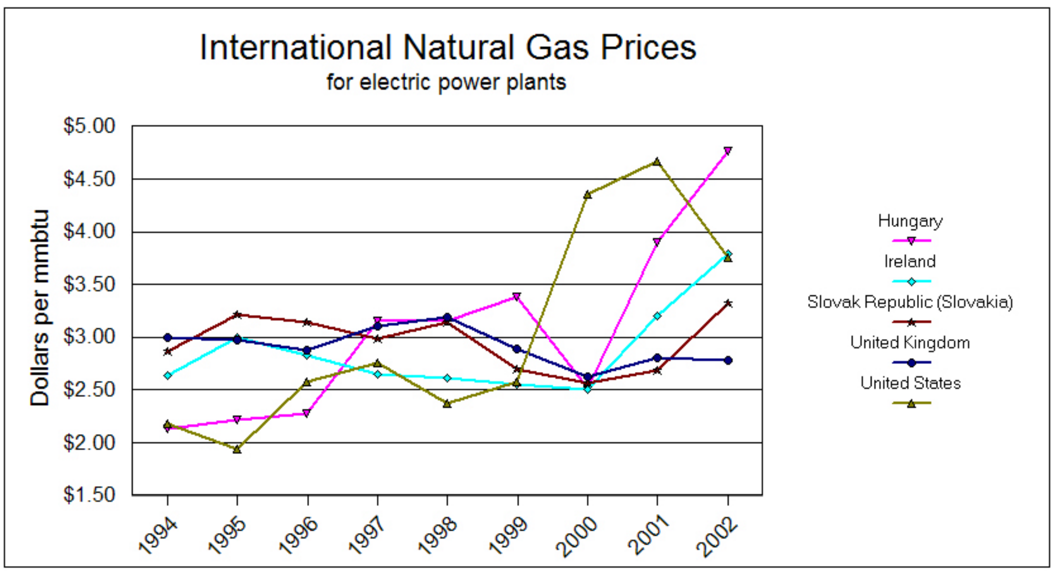
Beyond the price risk for natural gas are the supply risks. The depletion of North American gas wells is becoming more evident every year. To be clear, there is no imminent danger of "running out" of natural gas on this continent, there are vast quantities still in the ground. An inventory by the US Department of Energy in the mid-1990s reported that there was almost 2500 trillion cubic feet of technically recoverable natural gas in North America. (source: DOE Natural Gas 1995 Issues and Trends) This represents almost a 100 year supply. While not all of this will be economically recoverable, the majority likely will be, especially if natural gas prices continue to rise and technologies for extraction continue to improve.

The real supply risk is the effect of peaking production, and the inevitable decline that will follow. The average half-life of a well in the US, which is the time it takes for the well's production rate to drop in half, is currently only about two years—about half of what it was only a decade ago. The strategy of US policy makers has been to supplement domestic sources with increasing imports through pipelines and LNG tankers.

This strategy has limits. In North America, Canada is looking to divert an increasing amount of its natural gas resources to producing oil from its vast tar sands. This could easily consume a large portion of Canada's natural gas output, and there is concern that the US may never see any new supply sources from Canada due to the development of the tar sands.

LNG imports may open up US doors to the world supplies of natural gas. But, here too there is growing competition, from Western Europe as it tries to meet Kyoto targets with clean burning fuels, and with the rapidly developing needs of Eastern Europe, India and China. The global natural gas market is also vulnerable to the same price escalation and volatility as the US market. The chart below shows that in most years (except 2000-01), international prices were higher than in the US.

[Exhibit II-9: International Gas Prices, US Dept. of Energy, 2003)]



There are also significant security risks associated with the global sources of natural gas; half the world's reserves are in two countries: Russia and Iran. US relations with these countries have often ranged from unpredictable to terrible. Loss of these supplies during a conflict, should the US become directly or indirectly dependent upon them, would be more catastrophic than loss of the petroleum supply, since it would put the entire electric grid at risk. These considerations highlight the importance of developing local, renewable energy sources, and the value of reduced reliance on all fossil fuels, not just oil.

Avoided Carbon Risk

PG&E procures 3 percent of its electricity from coal, a source of energy that the CCA intends to avoid. Recent carbon reduction targets have been established under state law (The Global Warming Solutions Act of 2006, AB 32). Special targets under SB 1368 will apply to power plants based on emissions that are in excess of those emitted by natural gas electric generation. Since coal has significantly higher carbon emissions than natural gas, it is likely that there may be a significant carbon penalty placed on existing coal plants, and such penalties could arise from a number of potential legal restrictions. It is also likely that those generators that emit substantially less carbon than natural gas, such as renewables and/or verifiable energy efficiency, conservation or demand reduction, may be able to sell emission credits. The portfolio envisioned in this Plan is structured to allow a very favorable position regarding any potential charges for carbon emissions, and it may reasonably be anticipated as a future source of revenue for the CCA.

Avoided Nuclear Risk

PG&E owns a large nuclear power plant. There are many potentially large financial and operating risks associated with nuclear power, including repair, nuclear wastes, unanticipated outages and accidents, regulatory risk, and security threats. The CPUC has approved repairs and equipment replacement for Diablo Canyon nuclear facility in excess of $800 million that will be recoverable in rates. Any potential cost over-runs or further necessary plant upgrades pose a risk to PG&E ratepayers, a risk that is avoided by the CCA.

Appendix L:
H Bond Financing of the 360 MW "Roll-Out"[3]

The use of revenue bonds to achieve the objectives set out in Ordinance 86-04 will need to be determined on a project by project basis. Three of the threshold questions that must be addressed are (i) what assets or programs would best assist with the implementation of CCA, (ii) what revenue source will secure repayment of the H Bonds, and (iii) whether the H Bonds are tax-exempt or taxable. The first two are somewhat related in that if the items financed do not have an independent or sufficient revenue stream to support the bonds to be issued, a separate revenue stream for the H Bonds must be identified. The question of tax exemption will turn generally on the specific facts relating to ownership and use of the financed items.

Items Financed

CCSF's CCA Implementation Plan has determined that the City will require its power supply to be 51% renewable, including energy efficiency, by 2017. The other Bay Area CCAs mentioned above are seeking a 40 to 50% renewable requirement by the same year – far exceeding the 20% by 2017 required by state law. Were CCSF to take a similar course, its energy plan would contemplate a number of elements that should fall within H Bond financing.

These include renewable energy generation from wind farms, distributed generation utilizing photovoltaic technology, an electrolysis hydrogen facility, and energy efficiency programs. This also includes the developmental costs such as preparation of requests for proposals, environmental studies, and permitting, accounting and legal expenses, in addition to "hard-costs" of construction.

Sources of Repayment

H Bonds are "revenue bonds" issued by a municipality, county or Joint Powers Agency, which are to be secured by the revenues derived from fees and charges associated with the operation of an enterprise. Revenue bonds are commonly issued by state or local governmental entities and secured by the revenues of electricity or water enterprises or other revenue producing enterprises such as ports. The major point is that H Bonds may not be secured by or payable from CCSF's general funds. Rather, revenues from an

[3] This information is derived from the Nixon Peabody LLP Report of November 10, 2005 to the San Francisco Local Agency Formation Commission, Regarding Community Choice Aggregation.

operating enterprise must be the source of security or repayment. H Bonds allow, but do not mandate, the use of revenues produced by a facility built with proceeds of H Bonds to secure and repay those bonds, but revenues from other revenue producing enterprises may be used as security in lieu of or in connection with revenues from an H Bond financed facility. Under California law, revenue bonds such as H Bonds are excluded from the voter approval requirement of Art. XVI, Section 18 of the California Constitution, if they meet the requirements of the so-called "special fund doctrine." Under this exception, a debt otherwise requiring voter approval is not required if such debt is solely payable from, and secured by, revenues produced by an appropriate enterprise. No general fund or other tax revenues may be pledged to the repayment of such bonds.

In order to constitute permitted "revenue bonds," CCSF will need to identify a dedicated revenue source by which H Bonds are to be secured and repaid, whether revenues of a new source or an existing source. As noted, CCSF can structure H Bonds to be secured by the revenues from an existing revenue producing entity. Other financing scenarios, not discussed in that report, also exist and are discussed below.

H Bonds can be secured by revenues from a new enterprise such as the CCA or facility such as a renewable energy source that has not yet commenced producing revenues. This has the advantage of a logical nexus between the bonds' purpose and source of repayment. A disadvantage is the need to borrow additional moneys to pay interest on H Bonds during the construction period until such time as the facilities can produce revenues to pay the bonds.

Such a structure also has "construction" or "completion" risk that may result in a slightly higher interest rate on the bonds. In addition, the revenue production of a new facility to be built is uncertain which may also affect the interest costs that are attainable.

Securing the H Bonds with the revenues of an existing revenue producing entity avoids the disadvantages discussed above. However, such a structure does "tie up" a revenue producing enterprise of the City. A potential "hybrid" structure is to use a combination of the foregoing structures. Under this alternative structure the H Bonds could be issued secured by both a pledge of revenues from an existing enterprise and from any new enterprise. The pledge on the existing enterprise could be limited to the construction period during which the new facilities are not producing revenues or could be for the life of the H Bonds.

Another possibility would be to secure H Bonds with revenues available from a contract with a California-registered Electric Service Provider ("ESP") providing CCA services. Such revenues could be structured to constitute revenues of the enterprise(s), which would be the security for the H Bonds. For example, lease payments received from an ESP would constitute revenues that could be pledged as security.

Ultimately, the projects CCSF desires to finance with H Bonds will have a strong bearing on the security structure chosen. For example, if a significant portion of the proceeds of H Bonds will be used to acquire or implement non-revenue producing programs, the use of an existing revenue producing enterprise will be required. On the other hand, if a significant portion of the proceeds is used to acquire revenue-producing facilities, such facilities or related activities could serve as the security and source of repayment for the H Bonds.

In any event, a bond rating will be required for H Bonds secured by new or existing enterprises that do not already have a rating. The credit quality analysis conducted by the rating agency will, among other things, focus on the "coverage" provided by the pledged revenues. Generally, the rating agencies prefer pledged revenues that are 125% or more of the scheduled debt service on the bonds.

Tax Exemption

A variation of this alternative structure would be to create a single "enterprise" of the combined existing enterprise and the new facilities.

CCSF has a wide degree of discretion regarding the use of H Bond proceeds for renewable energy and conservation projects. However, the particular programs and users of facilities financed with the proceeds of H Bonds will impact whether the interest on such bonds will be tax-exempt under the provisions of the Internal Revenue Code of 1986, as amended (the "Code").

In other words, CCSF could use H Bond financing to provide its residents and businesses with the opportunity to purchase and own solar power with no money down.

In general, the "use" of facilities or items financed with the proceeds of H Bonds by an entity other than a state or local government could result in such bonds constituting "private activity bonds." In that case, under Section 141 of the Code, the interest is not tax-exempt. Such use is often referred to as "private use". Private use is present where there is any type of privately held "legal entitlements" with respect to the financed facility. Nongovernmental ownership constitutes private use as does long term contracts regarding the output to be produced by the facility. For example, a long term contract with a nongovernmental entity in which that entity agrees to purchase the energy output of a facility will generally constitute private use. In addition, contractual arrangements with nongovernmental entities regarding the operations and maintenance of a financed facility will constitute private use, unless such contractual arrangement is consistent with certain contract parameters approved by the Internal Revenue Service and described below. Last, it should be noted that loans of the proceeds of H Bonds to a nongovernmental person or entity will generally cause the H Bonds to fail to qualify for tax exemption.

Therefore, the facts regarding the ownership and operational structure of the financed facility will determine whether the bonds may be issued as taxable or tax-exempt. If CCSF owns and operates the facility, and if the power is delivered to customers of CCSF, then the facility will probably qualify for tax-exempt financing. It will also be possible to qualify for tax-exemption if CCSF contracts the management of that facility to a private party, provided the management contract requirements of Internal Revenue Service Revenue Procedure 97-13 (discussed below) are satisfied. On the other hand, if an ESP or other nongovernmental entity owns the financed facility or operates it pursuant to an arrangement that does not meet the requirements of Revenue Procedure 97-13, it will probably not qualify for tax-exempt financing.

H Bond proceeds can be used to fund energy conservation programs. However, to the extent such purpose is accomplished through a loan program wherein residential and business customers can make use of low interest loans in a CCA program to make energy conservation and efficiency improvements the loans of bond proceeds will cause the program to not qualify for tax exempt financing. Grants of bond proceeds could be made to individuals and businesses for conservation and other expenditures so long as an adequate project revenue stream is identified to secure and pay the bonds.

The fact that such H Bonds are not tax-exempt does not in and of itself make such a program nonviable. Taxable rates on such H Bonds could potentially still be substantially less that the rate of interest otherwise available on loans to residential and business customers.

There are a number of ways H Bonds could be used to finance renewable energy facilities. This can be accomplished either in a structure wherein CCSF (or other local government) undertakes acquisition, construction, ownership and management of the facilities or through structures wherein an ESP undertakes some or all of the activities. As noted, the tax-exempt status of H Bonds varies depending on the structure.

Structures wherein an ESP takes on one or more of the roles present issues under the Private Business Tests discussed above. Any lease or other similar arrangement with an ESP would likely result in the H Bonds being categorized as taxable “private activity bonds.” Again, such a result would not prohibit the structure but rather would result in a higher cost for these components of the program.

An alternative involving an ESP would be to utilize the management contract provisions under IRS Revenue Procedure 97-13 (“Rev Proc 97-13”). Rev Proc 97-13 describes safe harbor contractual arrangements that may be made with nongovernmental entities to provide management, operations or other services with respect to a tax-exempt bond financed facility.

Pursuant and subject to the requirements of Rev Proc 97-13, CCSF could engage an ESP to manage and operate renewable energy facilities financed with H Bonds without the ESP’s involvement being in violation of the Private Business Tests discussed above. As discussed below, Rev Proc 97-13 would permit a contract between CCSF and an ESP for managing and operating a renewable energy facility financed and owned by CCSF for as long as 20 years. Rev Proc 97-13 defines "management contract" as "a management, service or incentive payment contract between a governmental person and a service provider under which the service provider provides services involving all, a portion of, or any function of, a facility."

Rev Proc 97-13 focuses generally on the term of the contract and the manner and amount of compensation paid to the service provider. Generally, the more fixed in periodic amount the compensation paid to the service provider, the longer the permitted term of contract. Contracts pursuant to which the service provider's compensation is 80% fixed may be as long as 20 years in the case of service contracts relating to "public utility property". On the other hand, contracts pursuant to which the service provider's compensation is 50% fixed may not have a term in excess of five years.

"Public utility property" is defined as property used predominantly in the trade or business of the furnishing or sale of (i) water, sewage disposal services, electrical energy, (ii) gas or steam through a local distribution system, and (iii) certain telephone services and communication services.

Thus, for example, if the ESP is paid an annual fee equal to 8x and is also paid additional compensation in each year based on a variable component not in excess of 2x, then the contract can be for as long as twenty years. In addition, the ESP may be paid a one-time incentive award during the term of the contract, equal to a single, stated dollar amount, under which compensation automatically increases when a gross revenue or expense target, but not both, is reached. Further, a contract that satisfies the requirements of Rev Proc 97-13 may be renewed at the expiration of its term.

The full text of Rev Proc 97-13 is attached to this memorandum as Appendix A. A variety of the foregoing structures involving H Bonds could be used in tandem. For example, CCSF could enter into am energy supply contract with an ESP, which would not directly require the use of H Bonds. CCSF could then issue H Bonds to construct renewable energy facilities to be owned by CCSF. CCSF could then enter into a management contract permitted under Rev Proc 97-13 to manage and operate the facilities. Such a structure would allow for the H Bonds to be tax-exempt.

Appendix M
A Comparison of CCA in San Francisco, Ohio, and Massachusetts

In 2003, the National Center for Appropriate Technology through its National Affordability and Accessibility Project undertook a series of research studies on the effects of utility retail competition in five states: Massachusetts, Georgia, New York, and Ohio.[4] The information that follows describing the Ohio and Massachusetts markets were drawn from these studies with additional information gathered through additional research or interviews with representatives from the Ohio program.

1. Comparison of the Ohio and Proposed San Francisco CCA Programs

Background

According to the Public Utilities Commission of Ohio's (PUCO) August 2005 Annual Report of Market Activity from January 2003 through July 2005, nearly 170 cities, counties, and townships have formed government aggregations to purchase discounted power on behalf of their citizens. Currently, the largest public aggregator in the United States is the Northeast Ohio Public Energy Council (NOPEC). NOPEC represents 119 communities in nine (9) counties and more than 475,000 residential customers. There is also a multi-jurisdiction CCA in northwest Ohio, the Northwest Ohio Aggregation Council (NOAC) that represents nine (9) jurisdictions in the Toledo Edison territory.

According to PUCO's report, customers participating in aggregation programs in Ohio account for:

- Nearly 95 percent of residential customers;
- Nearly 88 percent of commercial customers; and
- Nearly 9 percent of industrial customers.

The small percentage of industrial customers participating in aggregation may be a reflection of the fact that much of the aggregation activity in Ohio has taken place in small rural communities.

[4] *Source.*

Because there were concerns regarding customers suffering from "sticker shock" once the market development period ended on December 31, 2005, the PUCO and four (4) of Ohio's five (5) investor-owned local electric utilities developed a rate stabilization plan to ensure the continuation of stable and competitive rates.

According to its agreed-upon rate stabilization plan (RSP), First Energy, the local investor-owned utility (IOU) servicing NOPEC, agreed to provide a competitive bidding process, or auction, to be conducted periodically on First Energy's electric load to determine if lower rates could be obtained. The first auction was conducted in December 2004. The PUCO rejected the results of the auction, finding that the RSP provided lower electricity rates. Business and residential customers were guaranteed that electric rates would not increase through 2008 except for fuel and material tax changes.

Ohio Regulatory Environment

In order for customers to make informed decisions, Ohio has legally required that suppliers must reveal the type of rate they offer: a fixed rate (same rate throughout the duration of the contract) or a variable rate (a rate that can fluctuate based on numerous factors), as well as a clear explanation of factors that cause a rate to vary. In addition, every certified electric supplier must provide a service contract upon enrollment. Included on that contract must be the following information: the supplier's name, phone number, address and toll-free number as well as the PUCO's toll-free number; switching fees to transfer from the local utility to a new supplier; an itemized list of prices, fees and the amount of recurring and non-recurring charges, in addition to the billing cycle and late payment fee information; and the electric suppliers' complaint handling procedures.

Switching Rules for NOPEC versus San Francisco's proposed program

Customers in the NOPEC territory are automatically included in NOPEC until NOPEC undertakes its biannual opt-out program. Customers who choose to remain with NOPEC during the opt-out period are enrolled for a period of two years. Customers wishing to leave before the two-year period has expired may be subject to a cancellation (or switching) fee.

NOPEC's program has the following attributes:

- After customers sign up with an electric supplier, their local electric utility will mail them a confirmation. Customers have seven days from the postmark date of this notice to cancel the contract. This is only one opt-out notice.
- Customers may be subject to a minimum stay requirement for default service. Customers who switch during the summer months are subject to a 12-month minimum stay provisions, but customers who switch back into default service during any other month may do so without restriction. Customers may also be subject to a maximum $5 switching fee.
- Customers have the right to terminate an electric supplier's contract without penalty if they move outside the electric supplier's service area or into an area where the electric

supplier charges a different price; or, the contract allows the electric supplier such a right in response to changing market reasons.

In contrast the San Francisco program will only have a mass opt-out period when the program is initiated. Potential San Francisco CCA customers will be notified and will have no fewer than four (4) opportunities to opt out.

Unlike Ohio, California law requires its CCA programs to have a Renewable Portfolio Standard (RPS). There is not currently a renewable portfolio standard in Ohio. SFPUC's staff understanding is that NOPEC is currently served by electricity generated almost entirely by natural gas and coal.

San Francisco's CCA program will include 360 MW of renewable generation and energy efficiency that is required by Ordinance 86-04. It is anticipated that the electric service provider that ultimately wins the competitive bid to provide electricity to San Francisco's CCA program will also undertake major elements of the design, construction, and operations of any renewable generation infrastructure that will be financed with bonds. Because of this requirement, San Francisco's contract period will be considerably longer than NOPEC's 3-year contracting cycle so that the CCA supplier and the City can be assured of bond repayment.

NOPEC Services
NOPEC also provides a natural gas component to its customers. For a CCA to provide gas aggregation, Ohio law requires that the gas aggregation be on the ballot similar to electricity. At this time, California law does not permit a gas aggregation program.

Ohio law does not mandate an energy efficiency program and thus, NOPEC's current program does not provide any energy efficiency services. However, NOPEC is currently investigating whether or not providing such services would make for an economic enhancement to its program. Contrastingly, San Francisco's program requires that an energy efficiency program will be a major business venture for its CCA program.

Despite its large number of customers, NOPEC, as we understand it, does not employ any city or county staff, rather it contracts out its power supply and has a separate contract with a small firm for accounting, reporting, and auditing requirements.

Contract Termination and Transfer
To facilitate the development of community choice aggregation and deregulation, Ohio law required that its investor-owned utilities shed twenty (20) percent of its customer base. This permitted the formation of both large multi-jurisdiction programs as well as individual CCA programs.

Despite this regulatory support, subsequent to the auction that was conducted by PUCO in December 2004 and a 2005 biannual opt-out period, Green Mountain, the electric power supplier to NOPEC, terminated its contract with NOPEC by invoking a regulatory option to do so. This resulted in NOPEC's customers being serviced by First Energy Services, a non-regulated affiliate of First Energy through 2008. At this time, NOPEC has filed a lawsuit against Green Mountain.

Other Ohio CCAs

There has been much focus and attention on NOPEC because it composed of 119 local jurisdictions. With respect to comparing it to concepts familiar to customers in California, NOPEC is a joint powers authority where members are represented on the board. There are, however, other cities that have chosen to be an individual CCA program and have not joined into NOPEC. One such city is Parma, OH with a residential population of 90,000.

Considered a suburb of Cleveland, OH, Parma was the first city to get voter approval to aggregate in March 2000. Parma was also able to take advantage of Market Support Generation (MSG) power, a special limited allocation of low-cost power made available to marketers in northern Ohio, for both city-owned facilities and town residents. This power was only made available in Northern Ohio to First Energy customers. First Energy made an allocation of 1,170 MW of power at a discounted price of 3.1 cents per kWh, which was available on a first-come-first-served basis to marketers with a specific list of retail customers. This allocation created some controversy because many marketers and government aggregators claimed that they did not have enough time to assemble a list of potential retail customers before the allocation disappeared.

By virtue of taking advantage of MSG power, Parma residents realized a 17-percent discount on their power prices, or about $60-75 per year, depending on usage. These discounts caused some complaints to arise that Parma had not fully complied with rules regarding MSG and that the city did not follow all of the necessary steps in acquiring their allocation. PUCO did believe the evidence underlying these claims were warranted and thus they declined to revoke Parma's MSG allocation.

This is an example of a specific type of CCA formation in Ohio that received a specific portion of energy, presumably from existing investor owned utilities, this option is not available to San Francisco or any other city or county in California.

2. Massachusetts Retail Electricity Market

To our knowledge there is only one CCA operating in Massachusetts – the Cape Light Compact. The Compact was officially formed following passage of the Electric Restructuring Act in Massachusetts in November of 1997. Currently the Compact is comprised of 21 towns that in total serve almost 200,000 residential customers. According to the Compacts web-site the current electric provider is ConEdison Solutions, it is implied on the Compacts web-site that this is a relatively short-term supply contract. Apparently only one opt-out notice is provided to Compact customers. Customers are free to leave the Compact – however return to the Compact appears to be at the discretion of the supplier. The web-site does not disclose the customer opt-out rate that has occurred for the Compact. The Compact lists six employees – however it is unclear if these are permanent civil service status employees or consultants.

As in California the Compacts supplier has to meet an RPS standard – attempts by the Compact to exceed this standard have not resulted in any bids from renewable suppliers. However the Compact is developing an option for its customers to purchase a renewable energy option. The Compact has an extensive energy efficiency program and reports annually to the Massachusetts Department of Telecommunications and Energy regarding these programs and energy efficiency goals.

A Comparison of San Francisco, Ohio, and Massachusetts CCAs.

	SF	NOPEC	Capelight
Demographics	Potential	Actual	Actual (date)
Number of Residential Customers		475,000 (2006)	About 200,000 (2006)
Number of Commercial Customers			
Number of Industrial Customers			
Number of Municipal Customers			
Total Load (MW)	potential peak 850MW (approx)		
Multi-jurisdictional (Yes/No)	No	Yes	Yes
Program Features			
Opt-out program requirement	Mandated by law as an opt-out program; four (4) opt out notices over 120 days. Also must provide new customers an opportunity to opt-out.	Biennial opt-out period. By law, NOPEC is required to notify customers allowing them to remain, join or opt out without penalty.	Apparently opt-out or leaving the program can occur continuously. Apparently only one-opt out notice is required to be mailed.
Customer Class Opt-Out rate (% load)			1% overall
Residential	TBD	Less than 10%	
Commercial	TBD	Less than 10%	
Industrial	TBD		
Opt Out for New Residents	TBD (potentially one opt out notice on a twice yearly basis)	21 days	Customers may opt-out at any time
Rate Setting Mechanism	First year by contract thereafter by external index		Apparently by indexed contract

	SF	NOPEC	Capelight
Meet or Beat Requirement	RFP requirement meet or beat PG&E generation rates	Residential & Governmental Customers save 5% through 2007.	
		Commercial & Small Industrial Customers save 1% through 2007.	
Procedure & Pricing for Signing up New Customers to the Aggregation Groups	New customers in San Francisco are automatically CCA then must be offered an opt-out opportunity	Customers moving into NOPEC's territory are assigned to First Energy until there is an open enrollment period. This coincides with the biennial opt-out period. All electric homes are excluded from the NOPEC program.	Apparently new customers in the Compacts service territory are automatically members of the Compact.
Other Fees Customers Should Expect to Pay	Potentially exit-fees for large customers leaving the CCA	No exit-fee	No exit-fee
Exit Fees	Customers will pay an exit fee to PG&E	By PUCO's rules, customers may be subject to minimum stay requirement for default service. Customers who switch during the summer months are subject to a 12-month minimum stay provision, but customers who switch back into Default Service during any other month may do so without restriction. The Commission approved a $5 switching fee. (this is more a condition of service than an exit-fee - lets discuss this)	A customer can only return to the Compact with the Suppliers permission.
Start-up Costs	Expected to be significant for staffing and Communications	Unknown	Unknown
Green Portfolio Acquisitions	Significant requirements for in-city renewable energy and a requirement to meet 51% Renewable Portfolio Standard by 2017	98% natural gas + nuclear; plans for one (1) photovoltaic demonstration facility in each of nine (9) participating counties; one (1) 10-megawatt wind farm	Meet Massachusetts RPS Standard. Developing a green portfolio option for Compact Customers
Bond Funding	Yes	No	No

	SF	NOPEC	Capelight
(Yes/No)			
Number of City or Government Employees	Could be significant.	Described as minimal with most functions performed by the Marketer and or a Consultant hired by NOPEC	Perhaps 6
Annual City Operating Expenses	Once CCA underway expected to be substantial for PG&E charges, staffing, and Communications		