Draft

COMMUNITY CHOICE AGGREGATION
DRAFT IMPLEMENTATION PLAN
AMENDMENT 1

City and County of San Francisco
Local Agency Formation Commission

San Francisco
April 15, 2005

local power
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AMENDMENTS TO APRIL 8 IMPLEMENTATION PLAN

The SFPUC and SF Environment have released a draft version of the Community Choice Aggregation Draft Implementation Plan. Several elements of the SFPUC/SFE plan, listed below, are on target and should be incorporated into the final Community Choice Aggregation Draft Implementation Plan. This amendment proposes incorporating the following elements into the final Draft Plan by referencing the sections of the Local Power plan where they should be included.

Add Opt Out Details
Add to Chapter V, Section 2.2 "Disclosure and Due Process in Setting Rates and Allocating Costs Among Participants"

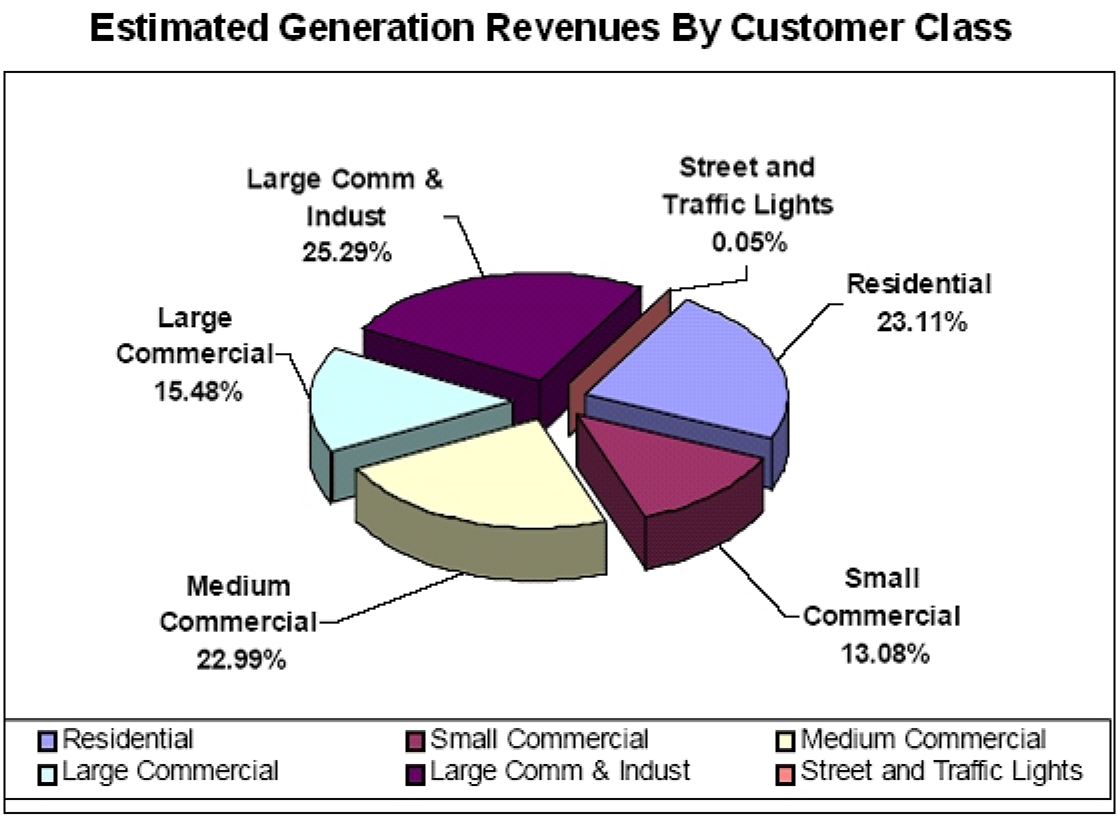
"If a customer declines to opt-out but later wishes to return to PG&E service, it will face CPUC-imposed switching rules to return to PG&E service. These rules might include a minimum time on rates tied to wholesale electric spot prices and/or a minimum commitment to remain a PG&E customer" (Ch. 1, p. 5).

"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] (Ch. 1, p. 8)

Get DA Customers In
Add to Chapter V, Section 4.2 "Outreach"

"CCSF businesses and organizations that are not served by PG&E today will not become CCA customers unless they opt-in with CCSF's consent. This category of customers includes BART, and existing Direct Access (DA) customers. A key strategic decision for CCSF will be whether to attempt to recruit existing DA customers whose high electricity usage may help to lower power costs for all CCA customers" (Ch. 1, p. 6).

"Although no market research has yet been conducted about customer response to potential products and services offering from a CCA in CCSF, basic customer demographics and energy usage patterns are available. Notably about 25% of larger business customer electric load in CCSF is currently served through DA - this equates to about 12% of the total potential CCA load. These accounts, some of the largest electricity consumers in the city, will not be automatically enrolled in the CCA and will have to be recruited upon the expiration of their contracts if the CCA wishes to do so. This might be worthwhile since large business customers offer a significant revenue base and often have electricity usage profiles that are flatter than average. Flatter profiles can potentially lead to lower costs to serve those customers and if their flatter profile helps to flatten out the average CCA profile, this may reduce electricity costs for all customers. **However it is the higher revenues available from CCA large business customers that are the most important consequence of their decisions to opt-out or choose CCA.** In addition maintaining a diversity of CCA customers will help reduce the regulatory risk of the CPUC advantaging any particular customer class in its PG&E rate design proceedings" (Ch. 1, pp. 13-14)



"Chart 2 above demonstrates the importance of large customers who comprise about 64% of the potential CCA revenues but only comprise a little over 1% of potential CCA accounts. CCSF residential customers also consume a smaller proportion of electricity in the higher consumption tiers 3, 4, and 5 than the PG&E average. This is important since PG&E electric generation rates for these tiers are far higher than the Tier 1 and 2 rate levels. Opt-out of CCA residential customers who consistently take power in tiers 3, 4 and 5 could also adversely impact the overall economics of CCA. It is important to recognize that the generation portion of electricity delivery costs varies significantly among customer classes and therefore the impact of higher than PG&E generation rates on customer's bills will also vary. For example for the average CCSF residential customer the generation portion of the electricity bill is about 35%, whereas for the largest commercial customers the generation portion of the bill is about 65%. Hence the city should anticipate that large commercial customers would pay particular attention to the rates offered by CCA" (Ch. 1, pp. 14-15).

San Francisco is a Big, Very Attractive Customer
Add to Chapter II, Section 1.0 "SF CCA Implementation Plan"

"Potential CCA customers in CCSF represent energy purchases larger than the single largest electricity customer in California: the UC/CSU system – a DA customer since 1998. A CCA in CCSF potentially represents about 5% of PG&E's energy sales and 7% of its customers. Given reasonable RFP requirements, it is highly likely that San Francisco as a single customer will be an attractive value proposition to wholesale electric suppliers. For example CCA revenues paid in rates by CCA customers could be $200 million annually, on par or greater than the City's current water and sewer revenues combined. Due to the electric market context and rules in California, the CCA is likely to engage in multi-year commitments to a supplier and potentially become an owner of new renewable power plants. CCSF could be a market leader in CCA, one of the early, if not the first of its kind in California, operating in a still evolving energy market" (Ch. 1, p. 10).

SFPUC Timeline Waits A Year With Jan 07 opt out (Ch. 1, p. 12).
Add to Chapter IV, Exhibit IV-1 "CCA Implementation Schedule Summary" and Appendix A

Add relevant CPUC related dates to the Implementation Plan Schedule.

Ongoing PG&E Procurement Issues
Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"Predicting PG&E's generation rates, the major competitor to CCA, is a complex forecasting exercise. PG&E no longer provides an open-book review of their resource mix and power contract terms – indeed due to concerns about use of market power and negative impacts on PG&E ratepayers a substantial amount of information regarding PG&E's contracts is now held confidential by the CPUC. This makes the forecasting of PG&E's average generation rates a complex process. Of course allocation of PG&E's generation costs among customer groups is also a dynamic process subject to CPUC regulation. PG&E's current rate allocation proposal in its General Rate Case (GRC) would, if approved by the CPUC, significantly lower generation rates for large and medium customers in CCSF while increasing generation rates for higher consumption residential customers. The net effect of PG&E's proposal would be to decrease the average PG&E generation cost for CCSF customers thereby increasing the competitive pressure on CCA generation rates." (Ch. 1, p. 16).

Bid Structure: Cape Light Compact vs. NOPEC
Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

Ultimately, the ratesetting goals established by the Board of Supervisors will determine what model is used for the supplier RFP. For example at one end of the spectrum, some large energy buyers provide their energy usage history by customer category in an electric supply RFP and ask for the best price for each category. The winning bid sets the rate for that category. On the other end of the spectrum, customers can identify an index on which to peg rates as well as the rate structure desired – for example a percentage discount off of each customer's PG&E rate schedule. To the extent that the constraints established by such an RFP approach create risk, the price of risk mitigation to meet proposed contract terms will be factored into RFP bid responses" (Ch. 1 p.7).

Major Findings of SFPUC Economic Study
Add to Chapter IV, Section 3.0 "Program Funding and Budget"

(Apart from its rate predictions)"The other major economic findings of the economics analysis (of the SFPUC plan) are as follows:

> The long-term economic value of the CCA will depend upon the superior contracting abilities of the supplier chosen by the CCA;
> The ability of the CCA to bond-finance wind resource development or similarly low-cost renewable energy projects is vital;
> And CCA construction of base-load natural gas facilities is likely to result in uneconomic results based on more competitive base-load alternatives." (Ch. 1, p. 18).

600 Megawatt Wind Facility
Add to Chapter IV, Section 3.0 "Program Funding and Budget"

"Of particular interest are the results of wind power investment for CCSF. Such investment appears economic only if the City can, via contracting, "shape" the wind-power delivery to replace wholesale market purchases of peaking power. However this investment in wind power will have to be much larger in MW output than is consumed by the CCA during peaking periods. This is a result of the assumption that the CCA will have to "re-buy" the shaped wind power for peaking needs in tradition 6X16 blocks of purchased power – a considerable portion of which is surplus to the CCA needs and is sold on the spot market. This wind project scenario, which assumes a City growth rate in electricity consumption of 1.65% per year, promises the greatest economic benefits of any of the scenarios examined in [by the SFPUC]" (Ch. 1, p. 18).

Build Not Buy
Add to Chapter IV, Section 3.0 "Program Funding and Budget"

SFPUC/SFE analyzed a scenario where a substantial amount of baseload renewable power would be purchased under contract as well as a significant amount of peak-load power. "In both cases the current market price referents established by the CPUC were used to price this power. The economic results of this scenario are not positive. This is due to contracting for peak renewable power – assumed to be solar – displacing competitively priced wind power; and contracting for baseload renewable power – likely to be biomass– displacing less expensive traditional market-based supply" (Ch. 1, p. 20)."

H Bonds Lower Costs of Service
Add to Chapter IV, Section 3.2 "CCA Contract Funding"

"The CCSF Ordinance requires the examination of Proposition H Bonds as a vehicle to augment CCA by providing for financing of renewable energy and conservation projects. Prop H bonds could offer lower cost debt than would be available to a commercial power plant developer. This cost advantage may be magnified if wholesale natural gas prices remain high or go higher. As long as gas prices are enough that electricity produced by gas-fired power plants is more expensive than electricity produced at wind plants, for example, wind plants will be able to sell the electricity at the marginal price of power – the gas-fired price. In those circumstances, cost-based wind power generated from municipally financed facilities may be attractive enough to outweigh the risks of long-term power plant ownership or leasing. The other attractive aspect of wind plant ownership, or long-term leasing, is the lack of fuel risk, both on price and physical delivery" (Ch. 1, p. 21).

RFP Sets Stage for Partitioning Risk
Add to Chapter V, Section 2.6 "ESP RFP"

"The RFP sets the stage for the partitioning of risk between the winning bidder and CCSF in the contract. One crucial factor in designing an RFP is to set the supplier incentives to fulfill the CCA goals (e.g., a shared savings/losses approach with a wholesale supplier might set the right incentives for aggressive supply contracting)." (Ch. 1, pg. 22)

ESP Should Take Risk
Add to Chapter V, Section 2.3.3 "Program Risk Analysis"

"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" (Ch. 1, p. 23).

Customer Characteristics and Context
Add a new Chapter VI, titled "Customer Characteristics and Context"

Incorporate SFPUC/SFE Chapter 2, "Customer Characteristics and Context") in its entirety by adding a new chapter (VI) to the final Draft Implementation Plan. Edit new Chapter VI for terminology consistency and cross referencing. See Attachment A of this Amendment for the current version of SFPUC/SFE Chapter 2.

Market to Direct Access Customers
Add to Chapter V, Section 4.2 "Outreach"

"Although legislative activity to reopen DA to new customers has occurred in both of the last two years, today DA remains suspended for new customers. Current DA customers may continue on that service, but customers who did not have DA contracts by 9/20/2001 may not choose DA service at this time. Current DA customers returning to bundled PG&E service must provide six months of advance notice and, once returned, must take utility service for at least three years. Thus, in order to prevent a customer who might be attractive for CCSF from choosing utility service upon their DA contract expiration, a CCA marketing team would have to identify attractive customers and recruit them to CCA service in advance of the expiration of their DA contract**" (ch.3, p.5)**

Resource Adequacy Requirements in Resource Constrained Area
Add to Chapter II, Section 5.0 "The Consequences of San Francisco's Aggregation"

"CCSF will also have to meet the CPUC's Resource Adequacy Requirements (RAR)

associated with serving its customers. These rules also apply to all electricity suppliers
and require operating and planning reserves of 15-17% in excess of load. In addition,
these requirements will require demonstration of compliance with the rules for the future
year's summer peak demand, also under consideration are specific resource adequacy
rules for LSEs serving specific resource constrained areas. San Francisco is currently a
resource-constrained area therefore any CCSF CCA might have to demonstrate specific
in-city resources to serve CCA customers. These rules will have a significant impact
CCA resource planning and ultimately generation rates for CCA customers" (ch.3, pp.6-7).

SF CCA CRS Not 2 Cents but 1.8 Cents/kwh

Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"D. 04-12-046 imposed a 2.0 cents/kWh CRS for all CCA customers for an 18 month period. This will effectively be reduced to a new 1.8 cents/kWh charge for PG&E customers who are served by a CCA since PG&E already charges approximately 0.2 cents/kWh for CTC that will be eliminated for CCA customers" (ch.3, p.6).

Low Income Customers – CARE

Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"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). As discussed briefly in Chapter 2, 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. Assuming the CCA would offer CARE rates identical to those offered by PG&E this might require, at least in the early years, a discount higher than the 40% currently offered by PG&E.[9] It is currently unclear from CPUC proceedings whether the subsidy for the CARE discount will be the responsibility of all of PG&E customers regardless of the generation supplier – this would make the CARE program CCA revenue neutral and will be addressed in Phase 2 of the CCA proceeding. However, the impact on CCA revenue of the CCA offering both the CARE discount, and the source of recovery of any revenue shortfall associated with CARE may have an impact on CCA rates" (ch.3, pp.10-11).

PG&E Controls Billing

Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"By law, CCAs will use existing utility billing systems. Thus, PG&E will be billing CCA customers on a monthly basis probably using PG&E's rate-ready billing option already used by some ESPs for direct access. CCSF will provide PG&E electric generation rates (and where appropriate electric demand charges) for each rate schedule the CCA serves.
This rate ready billing option currently costs 70 cents/bill/month. For CCSF as a CCA the yearly cost of using this approach is about $2.6 million (assuming zero opt-out of

CCA). This approach is simple and means that a customer will not receive a new bill due to CCA. However, the rate-ready billing method limits the options for CCA ratesetting to rates designs which can be implemented within the current PG&E billing system" (ch.3, p.11).

PG&E's Ratesetting Process at the CPUC

Add to Chapter V, Section 2.2 "Disclosure and Due Process in Setting Rates and Allocating Costs Among Participants"

"PG&E rates are set under the CPUC ratemaking process. First, PG&E's revenue requirement for a future time period is set based on the forecasted cost to serve its forecasted demand for power over that period of time. The annual revenue requirement is the amount of money that PG&E must collect through billing its customers over a year, including capital costs, variable costs (including fuel and O&M), contract costs, taxes, and return on investment. The proceeding in which the revenue requirement is determined is called Phase 1 of a General Rate Case (GRC)."

"The revenue requirement is allocated over PG&E's forecast sales in Phase 2 of the GRC to determine the average rate that must be paid by each class or rate schedule of customers in order to produce that amount of revenue. Since it is spread over *forecast* sales, the amount of revenue actually collected will never exactly equal the revenue requirement. Excesses or shortfalls in revenue are tracked and applied to adjust the revenue requirement for the following year. PG&E is also authorized annual revenue requirement adjustments for inflation and capital additions, called attrition adjustments.
Separately, PG&E has an annual review of its generation costs, with annual rate adjustments. More frequent adjustments are permitted if its costs and revenues diverge by more than five percent."

"Once the revenue requirement is determined, it is allocated among customer classes and
rate schedules within the customer classes. The basic framework for this allocation is
set every three years in Phase 2 of GRC. The revenues to be collected are allocated
among the various customer classes based on the marginal cost of serving the different
classes. Next, revenues to be collected within a class are allocated to rate schedules
within each class. Once the revenues have been allocated, rates are set such that the
usage characteristics expected of the sales for that group of customers, when multiplied
by the rates, will produce the desired amount of revenue."

"Some classes, like residential, simply have charges per kWh of usage. Others also have
demand charges, based on the maximum instantaneous demand of a given customer over
a month, or the maximum demand during the peak period of system demand. Some have
time-of-use rates, where the kWh charges vary by time of day. Lastly, some customer
classes pay customer charges, which are fixed charges per month designed to capture the
fixed costs of serving the customer, like metering and billing."

"For the purpose of CCA service, the key factor for CCSF is allocation of revenues to
recover supply costs, since PG&E's delivery, metering and billing costs are included in
PG&E delivery charges. PG&E's generation costs include the utility's own generation
costs from its power plants and purchased power contracts, as well as a share of DWR
contract costs, as determined by the CPUC through its allocation methodology for DWR
power contracts."

"The utility must also recover other generation related costs like CTC and DWR Bond
Charges from *all* customers, including CCA and non-exempt DA customers, as part of its

delivery charges. In the case of a CCA, its generation costs will be those of the supplier contract plus the CRS charged to CCA customers by PG&E. This is why CCAs have to account for the CRS charge in their economic evaluation since this is a new rate component that CCA customers will be paying. A CCA may also include additional costs incurred for energy efficiency, demand response, or renewables acquisition undertaken by CCSF itself, as opposed to by its supplier, in it generation rates."

"Generation-related costs for utilities are recovered using demand and energy charges for larger customers and energy charges for smaller customers. As noted above, CCSF will have to decide whether to model its generation rates after those of PG&E, i.e. with demand and energy charges, often varying by time of use, for appropriate customers, or whether to model its rates after the charges imposed by its supplier, which may only be energy-related (i.e. volumetric) charges."

"CCSF will also have to decide how to adjust its rates in relation to rate adjustments by PG&E. This was discussed somewhat above. CCSF will have to decide whether to make its generation rate changes at the same time as PG&E makes generation rate charge changes, even if its costs change on a different schedule, and how to handle the passthrough of its own cost changes resulting from its suppliers s billing on the same or a different schedule" (ch.3, pp.12-13).

PG&E'S GRC PHASE 2 REVENUE ALLOCATIONS AND RATE PROPOSAL

Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"PG&E's Phase 2 proceeding is underway at the CPUC and expected to be decided by the Commission by the end of 2005. PG&E has indicated that it would like to settle this proceeding. There will be active participation from residential, commercial, industrial, agricultural, and street-lighting customers, the latter of which are cities and counties. PG&E's revenue allocation proposal is to increase residential revenue allocation, maintain small business customers close to current revenue allocation, and provide a sizable decrease for the majority of medium and large customers (with the exception of standby customers who would see a revenue allocation increase)."

"Compared to 2004 energy generation charges this overall revenue allocation proposal translates into energy generation charges which are: increased across the board for residential customers including CARE customers, slightly decreased for small commercial customers; and significantly decreased for medium commercial, large commercial, and the largest commercial/industrial customers. The overall impact of the proposed revenue allocation and rate design change is to decrease the overall generation cost to serve CCSF by half-cent/kWh or about 6%. Based on 2003 loads and early 2005 PG&E generation rates, the average generation cost to serve CCSF customers was 6.3cents/kWh. Should this PG&E GRC Phase 2 proposal be approved as filed by the CPUC this average PG&E generation cost to serve will drop to about 5.9 cents/kWh."

"This average generation rate would provide a formidable challenge to making CCA economic. For example, assuming an average 1. 8-cents/kWh CRS energy charge then the all-in cost to serve CCSF customers could not competitively exceed 4.1cents/kWh in 2006." [last sentence deleted]

"One of the more complex issues for PG&E's proposed rate design is how to set residential rates. This is because there are many constraints on residential rates that have been imposed by legislation and prior CPUC decisions."

"The first constraint was imposed by the passage of AB 1X in January 2001. As discussed in Chapter 2, this legislation permitted *no* increase in residential rates for customer usage up to 130% of the customer's baseline amount. The baseline amount has been set in CPUC proceedings and varies by climate zone and type of energy usage in a dwelling (e.g. mix of gas and electric usage). This prohibition of any rate increase has meant that any residential rate increases must be applied to usage in excess of 130% of baseline. About 73% of PG&E's residential consumption is protected from rate increases because of this legislation and other CPUC-imposed restrictions on increases for customers receiving CARE rate (for low income customers) or on medical baseline allowances. Thus any rate increases must be imposed on only 27% of residential usage, or be shifted to other customer classes."

"In Phase 2 of its current GRC, PG&E proposes to try to allocate the shortfall from the 130% of baseline rate-cap within the residential class. However, PG&E also proposes to cap the overall residential increase, which means some of the costs will spill over to other classes. The other classes will oppose this shift of costs in their direction. This debate in the PG&E rate proceeding illuminates how similar ratesetting issues may affect the CCA product design."

"Related to the baseline rate issue, PG&E's residential customers have increasing block rates. Baseline usage sets the amount of energy in the first residential tier, while the second tier includes usage from 101% to 130% of baseline usage. There follow three tiers with increasing rates for increasing usage, with the blocks sized on the basis of the baseline quantity for the customer in its climate zone."

"In the GRC Phase 2 proceeding, PG&E proposes to retain five residential tiers but establish the same rates for Tiers 4 and 5. CCSF will need to consider whether it also wants to establish a comparable tiered residential rate structure. If so, it should consider whether it wants its rate tiers to increase such that it maintains the same price differential among the residential rate tiers as does PG&E. But the rate-ready billing requirement will require that the overall structure of CCA rates fit within PG&E's billing constraints.
PG&E also makes proposals for larger customers in its Phase 2 proceeding."

Mandatory TOU (Time of Use) rates for all customers over 500 kW

Voluntary TOU for all smaller customers

Choice of rate options for smaller customers, e.g. optional demand charges and/or TOU energy charge options

Revenue neutral TOU and non-TOU rates for customers less than 500 kW

Switch all customers above 500 kW to recording usage at 15 minute demand intervals for meters with this capability

Increase in customer charges, with greater increases for higher voltages

Seasonal differential in distribution related charges at 1.5 (summer): 1.0 (winter)

TOU Ratio of summer combined distribution demand and energy charges: 2.5:1.0:0.5

TOU Ratio of winter combined distribution demand and energy charges: 1.5:1.0

Collect 20% of allocated generation revenue as capacity (20% through demand charges for higher voltage customers and less for lower voltage customers) with rest in TOU energy charges

Customer charges for standby customers (which would apply to backup service for self-generation or distributed generation customers) will be the same as for full requirements customers; standby customers will also pay peak demand-related distribution revenues on a TOU kWh basis, and will pay all other generation and distribution costs as reservation charges."

"Some of PG&E's large customers take interruptible service. They receive lower rates in exchange for being available to shut down their usage in case of system supply or reliability emergencies. Given its load pocket characteristics CCSF may have to investigate whether to encourage such an option for its own customers. CCSF must consider whether it would like to pay incentives and have its own program for load reductions so that it can get credit for demand response for resource planning purposes."

"If CCSF chooses to do so, it must decide whether or not to set its incentives at the same level as PG&E or greater. Additionally, CCSF would have to consider whether its customers could participate in both load reduction programs, or if there could be double counting of demand reduction as a result. CCSF would also have to decide to coordinate its demand response program directly with CAISO, through its supplier, or through PG&E" (ch.3, pp.13-15).

The CCA Product Line Will Impact Ratesetting

Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"CCSF may decide to pursue "demand response" rates, such as Critical Peak Pricing (CPP) and Real-Time Pricing (RTP). These rate options are designed to charge high rates when supplies are tight or reliability is threatened, in the expectation that customers on these rates will reduce their usage. All of these rate options require advanced metering. Currently these meters and rates are only available to PG&E's larger customers."

"The competitive landscape for demand response rates is in flux. The CPUC has ordered PG&E and other utilities to provide plans by March 15, 2005 for expanding advanced metering. In addition, the CPUC has ordered PG&E to file critical peak pricing default rates for implementation in summer 2005 for all customers over 200 kW."

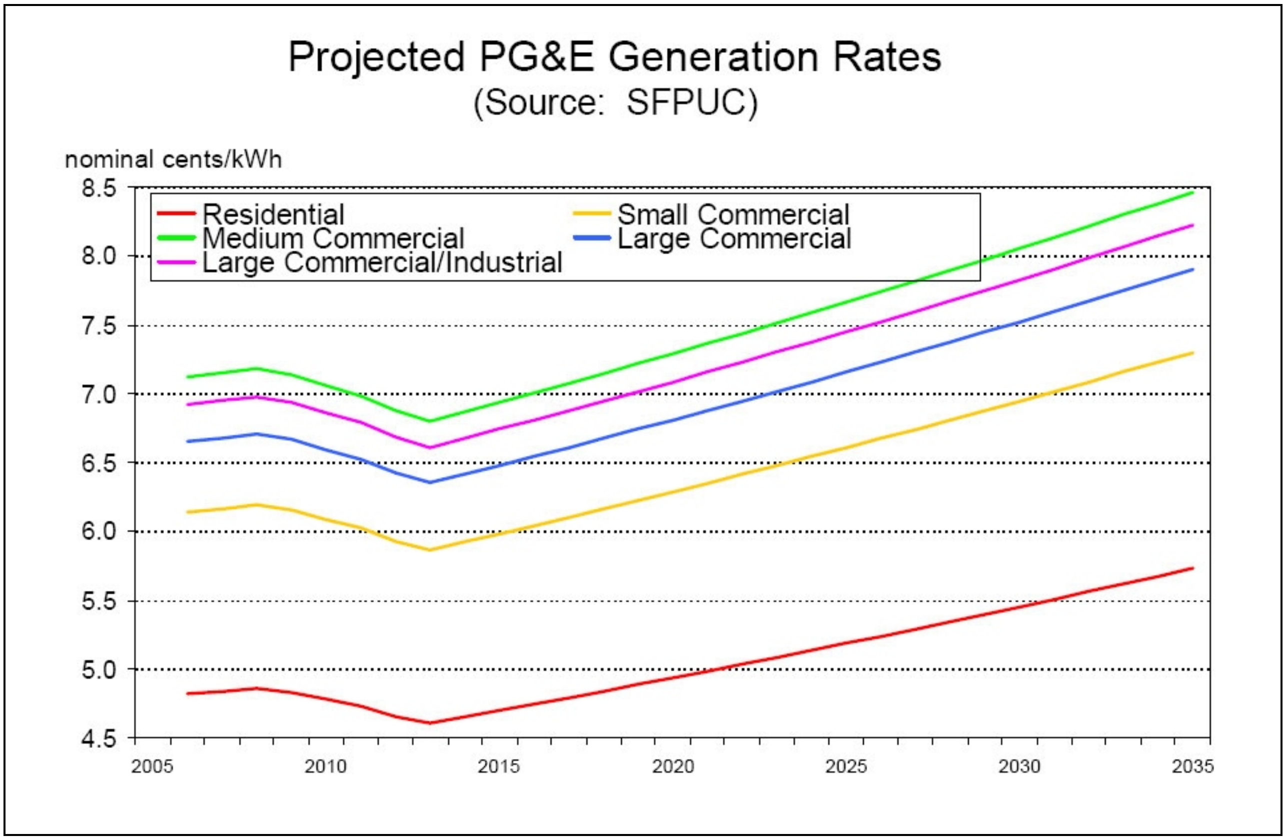
"Such rate options (e.g. interruptible, CPP, RTP) could be part of CCSF's demand response component of its resource plan, to help meet resource adequacy goals" (Ch.3, pp.16-17).

Other CCA Costs
Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"Besides power procurement and the CRS, a CCA will have also incur other costs that it must recover from its customers. The most significant of these are: billing charges from PG&E; its own administrative and operational costs (most notably a call center); and charges assessed by the CA-ISO. As seen in Figure 6, for example, these other CCA charges are a minuscule portion of the CCA's total costs each year. As such, the other factors discussed above will have a much greater impact on the CCA v. PG&E cost comparison over the long term. Nonetheless, the Contract Mix Model has been designed to accept alternative assumptions on all of these other CCA costs, to evaluate the potential impacts on the cost comparison." (Ch. 3, p. 52)

Projected PG&E Rates
Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

Add following figure to discussion of projected rates. (from Ch. 4, p. 11)



The Renewable Portfolio Standards Will Likely Have To Be Met With Both Peaking And Baseload Resources
Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"… if there are to be Supplemental Energy Payments (as defined by the CEC), these payments would be made outside the price system for electricity generation (however they may be incorporated as higher electricity distribution rates). ... In the CCA v. PG&E cost comparison, we identified favorable cases for the CCA option that assumed the CCSF CCA built its own renewable energy for its peaking (6x16) needs only. The Contract Mix Model calculates the share of this renewable energy in the CCA's overall portfolio. The cases we investigated showed that the share of this 6x16 renewable energy was only about 13 percent of total energy supplies in any given year. This result leads us to believe that LSEs cannot expect to meet the RPS on a percentage-of-consumption basis with peaking supplies only, and that they will likely have to include renewable resources in their baseload supplies. Alternatively, LSEs generating and selling renewable power could keep any RECs for themselves as an approach to meeting the RPS standard." (Ch. 4, pp.53-54)

Contracting Regulations
Add to Chapter V, Section 2.1 "Rate Design, Rate Setting and Other Costs"

"The Contract Mix model allows for the overlay of the presumed regulatory requirements for CCA contracting. According to Altos' and the SFPUC staff's understanding, CCAs will, by CPUC regulation, have to meet certain requirements both forward contracting and reserve margin to ensure resource adequacy. The Contract Mix model accounts for both of these regulations."

"The current understanding of the forward contracting requirement is that:

1. By September 30 of every year, every LSE must contract for capacity for at least 90% of its projected load for each month in the following peak summer season (i.e., the following May through September); and
2. all LSEs will have to be fully contracted for capacity and energy at least one month ahead of time to meet expected loads."

"These regulatory scenarios leads naturally to questions about the development of separate markets for generation capacity and electric energy in California, and the potential linkages between these two markets. While some might suggest that the capacity market and the energy market will be entirely separate, distinct, and independent, Altos believes, to the contrary, that the markets for energy and capacity, as expressed in their prices, will be absolutely linked, and that they cannot be un-linked."

"To understand this point, let us understand that an LSE would make capacity payments to a generator in, say, September 2006 to "lock in" generation if the LSE needed to call on it during May – September 2007. Then, if the LSE needs the power from that generator, the LSE would make an energy payment to the generator and the power would be generated and consumed. In this construction, the capacity payments would generally cover the generator's fixed costs, while the energy payments would typically cover fuel and other non-fuel operating costs (if any). The question arises, then, what will be the relationship among the capacity payment (made in September 2006), the energy payment (made in Summer 2007), and the prevailing price for spot energy (the "all in" price during Summer 2007)?"

"Altos believes that the sum of the capacity payment and the energy payment must equal the spot price (at any hour that the LSE calls for power from the generator): Capacity + Energy = Spot (C + E = S). No other solution is economically rational. Consider the LSE. Hour-by-hour, his supply alternatives are: purchase power from the generator he has under capacity contract or purchase from the spot market. The rational LSE will not, consistently and over the long-run, pay more to the contracted generator, in total (i.e., for capacity plus energy), than the power is worth in the spot market at any given hour. On the other hand, the rational generator cannot expect to receive, consistently and over the long-run, capacity and energy payments whose sum exceeds the market-determined value of power on an hourly basis. Both sides will expect to be "price takers" in the very large WECC market of generators and purchasers, and the price that both sides will calibrate to is the hourly "all in" or spot price."

"This calibration to the spot price means that capacity payments and energy payments will have an inverse relationship. If capacity payments are high, the subsequent energy payments (made when the electricity is actually needed) will be low. If the capacity payments are low, the energy payment will be high. In every case, the energy payment will make up the difference between the capacity payment and the spot price at the time the energy is delivered."

"This inter-relationship among capacity, energy, and spot prices is captured in the NARE Model and the Contract Mix Model. We represent the CCA purchasing power contracts at an "all in" price (i.e., the sum of capacity and energy). This "all in" price reflects the total cost to the CCA for this power. While in the "real world" these payments would be made at two different times (capacity in September and energy in the following summer), the total cost to the CCA is the important value, and that value is reflected in the "all in" price that we use."

"The Contract Mix Model represents the reserve margin requirements by increasing the amount of power the CCA must have contracted for the peak demand periods, using the following input factors (found under Miscellaneous Inputs):

> Resource Adequacy Reserve Cutoff: This factor indicates the hours for which the reserve adequacy requirements are in effect. The current understanding of prospective CPUC regulations on this issue is that the reserve adequacy requirements will be in effect during all hours when the projected load is expected to be at least 90 percent of maximum load (i.e., the 10 percent of hours with the highest load).

> Resource Adequacy Reserve Margin: This factor determines how much extra power needs to be contracted for during these hours. The current understanding of prospective CPUC regulations on this issue is a 17 percent reserve margin.
>
> Coincidence Factor: This factor reduces the necessary reserve margin, to account for non-coincident peak loads. The current simplifying assumption regarding prospective CPUC regulations on this issue is for a 2.5 percent factor."

"Using the currently proposed values, for each of the top 90 percent of hours, the CCA would have contracted an amount of power equal to: Base Load x 1.17 x (1-0.025) or about 114.1 percent of the projected load."

"These resource adequacy requirements, if enacted by the CPUC, would constrain a CCA's contracting program to a "net long" position in every month (see Figure 25 above) if purchasing standard 7x24 or 6x16 wholesale market products. Thus, unless the CCA customers' power demand unexpectedly exceed the forecasted demand (e.g., due to hotter-than-average summer weather), the CCA would be selling excess contracted power every month into the spot market, presumably at spot prices." (Ch. 4, pp. 62-64)

ATTACHMENT A

SFPUC/SFE COMMUNITY CHOICE AGGREGATION
DRAFT IMPLEMENTATION PLAN
CHAPTER 2: CUSTOMER CHARACTERISTICS AND CONTEXT

ATTACHMENT B

INTERIM CCA TARIFFS (REDLINE)
SUBMITTED BY PG&E TO CPUC
FEBRUARY 22, 2005