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Community Choice Aggregation Program Report

Submitted to:

San Francisco Local Agency Formation Commission

Final Version - February 28, 2009

(San Franciscans Use Mirrors to Reflect the Sun onto the City Hall Dome at Community Choice Rally, May 2006).

Contents

1. Background and Introduction

On August 20, 2008 the San Francisco Local Agency Formation Commission (SFLAFCO) directed Local Power Inc. to begin work on this Community Choice Aggregation (CCA) Program Report. The purpose of this report is to outline and recommend a course of action regarding ongoing energy developments, public and/or private, that might be adapted to augment San Francisco's CCA and H Bond Program (CCA Program) as approved in Ordinances 146-07 and 147-07 in 2007, as well as the original CCA Ordinance 86-04 in 2004. These ordinances established minimum CCA Program bidding requirements, approved a detailed *CCA Program Design, Draft Implementation Plan and H Bond Action Plan*, and created a joint agency process for the San Francisco Public Utilities Commission (SFPUC) and San Francisco Local Agency Formation Commission (SFLAFCO) to prepare a CCA Request for Proposals (CCA RFP) for approval by the Board of Supervisors, for which this Program Report serves as an initial supplement.

> **Purpose of CCA Program Report**: outline ongoing energy project developments and recommend a course of action that might augment the City's CCA Program as defined by Ordinance 147-07 and 146-07.

The CCA Program Report marks a shift from defining policy toward preparing for prospective suppliers to meet the City's requirements for renewable resource development, energy supply portfolio, and rate schedule. The City will seek a CCA Supplier to assume power supply responsibility citywide and build 360 MW of renewable energy and demand-side technologies as part of the new service. In order to qualify, a CCA supplier's bid must, a) commit to a 51% Renewable Portfolio Standard (RPS) by 2017, including energy efficiency and conservation technologies, and; b) commit to meet-or-beat PG&E's rate schedule for all ratepayer classes initially, followed by a proposed structured rate into the future. The proposed rates will include the costs of designing, building, operating and maintaining 360 Megawatts (MW) of new renewable energy capacity in and near San Francisco[1]. The 360 MW of energy infrastructure will be financed by the City using its voter-approved "H Bond" Authority.[2] The new facilities will become mostly City-owned but will also offer participating residents and businesses financing to purchase and own local solar photovoltaics and other local renewable energy and demand-side technologies.

This CCA Program Report begins to identify opportunities and potential problems that ongoing energy developments in the City might present for the required 360 MW infrastructure rollout. While the adopted CCA Program Design defines minimum

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[1] *City and County Draft CCA Implementation Plan, CCA Program Design and H Bond Action Plan*, dated June 6, 2007 by Ordinance 147-07, (File No.070501), adopted as an Amendment of the Whole by the Board of Supervisors June 19, 2007, signed by Mayor Newsom on June 28, 2007, Exhibit II-2, p.37.

[2] Section 9.107.8 of the City Charter, Proposition H, 2001 – Ammiano.

installed capacity requirements by category,[3] questions remain about how to provide the approximate 650 MW of peak load in the CCA program,[4] how to minimize environmental damage from remaining "brown" resources and maximize system resiliency. Within this context, this report addresses several key questions:

- *Can the City's CCA Program obtain access to Hetch Hetchy hydropower? Does CCA create the opportunity to get over legal barriers in its contractual relationship with Pacific Gas & Electric (PG&E) and in the Raker Act?*

- *What opportunities are there for converting existing natural gas steam boilers into cogeneration facilities? Would these be included within, or additional to, the 360 MW renewables rollout?*

- *What are the prospects for tidal power development for the Golden Gate and other ocean resources?*

- *What City permitting or zoning changes are needed, starting in 2009, to prepare agency officials to help implement a 360 MW rollout of renewables?*

- *What regulatory actions are needed to prepare the renewables/efficiency rollout?*

- *How should the City establish a CCA Energy Efficiency program while protecting Department of the Environment budget and planning requirements?*

- *How might the City's ongoing solar programs be integrated into the CCA?*

- *Does the Trans-Bay Cable make a Delta Wind facility more likely? Should the City look at off-shore wind?*

Recently, SFLAFCO commissioned Michael Bell Management Consulting Inc. (MBMC) to review prospective CCA Supplier responses to the adopted *CCA Program Design, Draft Implementation Plan and H Bond Action Plan* in the San Francisco Public Utilities Commission's (SFPUC) 2007 CCA Request for Information (CCA RFI). In its analysis of the RFI responses,[5] MBMC confirmed the robustness of the market approach of the City's adopted Draft CCA Implementation Plan[6]. MBMC recommended no major structural modifications of the Draft Plan, validating its overall portfolio and rate structure strategy. MBMC praised the City's decision to leave design flexibility for the CCA Supplier while maintaining a strict, clear 360 MW renewable rollout requirement

[3] 150 MW wind, 107 MW demand-side, 103MW renewable distributed generation including 31 MW (dc) solar photovoltaics on private and public sector rooftops.
[4] Historical peak demand has varied significantly from year to year
[5] SFPUC CCA RFI respondents included Citigroup Global Markets, Northern California Power Agency, Constellation New Energy, Energy Services Group, Shell Energy of North America, and Pacific Economics Group.
[6] Michael Bell Management Consulting Inc (MBMC), "Report: Community Choice Aggregation – Suggested Implementation Plan, Request for Qualifications, and Request for Proposal Modifications," submitted to the San Francisco Local Agency Formation Commission, May 23, 2008, pp.18-19.

and an equally clear and achievable 51% RPS by 2017. MBMC also agreed with the general approach of the Draft CCA Implementation Plan's effort to place performance risk, revenue risk and design risk on the CCA Supplier, achieved through the Design, Build, Operate-and-Maintain mechanism,[7] the CCA Supplier's commitment to competitive structured rates, and the required performance insurance and bonds to cover any procurement- or construction-related costs that might arise in a worst-case scenario. The 360 MW infrastructure rollout requirement specifies:

- at least 103 MW of local renewable distributed generation including at least 31 MW of photovoltaic capacity on private and/or public city rooftops
- 107 MW in efficiency and conservation technologies installed at San Francisco residences and businesses
- a 150 MW wind farm

This Program Report addresses each of these major categories, and also identifies several key power generation opportunities that we believe will enhance the overall economics of a San Francisco CCA Service. A wide range of resource options for prospective CCA RFP Respondents is critical for an informed, successful negotiation process. This Program Report provides initial recommendations regarding key program elements, and identifies potential resources for a CCA. A great deal more definition will be provided by a subsequent "CCA Program Basis Report" in order to enable preparation of a CCA RFP that will allow the City and its chosen CCA Supplier to make an informed commitment as partners with substantial responsibilities projecting decades into the City's future.

The main purposes of the CCA Program are to build green power locally and provide a competitive, more predictable electricity rate alternative to Pacific Gas & Electric (PG&E) service for San Francisco residents and businesses. The H Bond Authority is the mechanism upon which the "build" component of the CCA Program depends. The structure of the City's CCA and H Bond Program makes a public works-scale rollout of green power facilities a requirement of its CCA Service Agreement: it is a "build more, buy less" approach, meaning that the CCA will attempt to avoid much of the risk and extra expense of relying on power purchases in the open market to supply its requirements for renewable energy. H-Bond financing accomplishes several goals:

- it allows for local ownership and control of energy resources
- it reduces the lifecycle cost of capital intensive green energy projects
- it raises money for building new green energy facilities
- it avoids the need for tax revenues
- it enables rapid deployment of renewables

[7] Draft CCA Implementation Plan, p.123.

Under the adopted CCA program design, H Bond financing will be repaid by monthly CCA Program electric bill revenues, each month, over the term of the CCA Agreement, reaching one or more decades into the future.[8] The CCA Program structure, as defined by existing local law, emphasizes the importance of preparing prospective CCA Suppliers to implement an accelerated rollout of at least 210 MW of green power technologies within the City and County of San Francisco during the first years of the CCA Agreement, as well as a 150 MW wind farm.

The San Francisco CCA program is one of the most ambitious clean energy programs in the world. Implementing the 360 MW rollout will be unprecedented in scope for a local government, measured by the cost of the infrastructure [9], by the diversity of technologies included in the rollout: solar, wind, demand technology, various renewable distributed generation technologies, and —as this report identifies— potentially cogeneration and ocean power. As with any innovative program, a level of sophistication by the City is necessary in order to have a likelihood of success with contractors. This CCA Program Report is the first in a series of reports, together comprising the Program Basis Report, which will be necessary to prepare, with due diligence, a Request for Proposals for approval by the Board of Supervisors, as required by Ordinances 86-04 and 147-07.

The CCA rollout process will require (1) a data-rich environment in which locally available renewable, demand-side and clean power *resource opportunities are identified for consideration by prospective CCA Suppliers*, and (2) establishment of a parallel-process or "blanket" planning approach to site identification, approval and development that *minimizes the likelihood of City-side delays* to the CCA Supplier's planned rollout. A primary focus of this Report is therefore the identification of energy resource opportunities in San Francisco that may help augment the CCA Program. We evaluate technical issues related to these new opportunities based on ongoing energy developments in the City. Some of the current developments are City-based, such as Hetch Hetchy power or the Mayor's solar program, while other opportunities or issues are private sector developments such as cogeneration and the possibility of using the Trans-Bay Cable project as a highway to developing a wind farm and/or other renewable resources in the Delta.

A major challenge for a large roll-out of local clean energy infrastructure is the regulatory framework. Internally, the City will need to redefine permitting and zoning rules and

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[8] MBMC's analysis of the adopted Draft CCA Implementation Plan and RFI Response by prospective CCA Suppliers suggested a 25-40 year duration for the CCA Agreement to support a 51% RPS rollout; all CCA Ordinances leave the duration to CCA RFP respondents based on their proposed portfolio and rollout schedules. See "Report," May 23, 2008.

[9] In Local Power's opinion, a preliminary rough estimated cost could be: 150 MW wind projects at $2 per watt = $300 million, 25 MW (ac) photovoltaics at $8 per watt = $200 million, 72 MW distributed generation at $4 per watt = $288 million (this assumes the resource requirement is primarily met by fuel cells, however, the real cost will depend on the exact mix of energy sources), and $107 million for 107 MW of efficiency and conservation costing on average $1 per watt. The total 360 MW infrastructure would then cost approximately $895 million; noting however that actual cost for the infrastructure could vary significantly from this estimate.

procedures to streamline rollout processes. [10] The report also highlights external government activities that can support key elements of the CCA Program. One of most urgent is that the City should petition the California Public Utilities Commission to become an administrator of the Public Goods Charge (PGC) funds for Energy Efficiency. Every year, San Franciscans pay $17 million for this program, and the City should attempt to get its fair share. This City must apply to administer these funds in conjunction with the CCA program, starting in January, 2010 or as recommended by SFLAFCO.

According to the Draft CCA Implementation Plan, the CCA Program will offer H Bond financing to all San Francisco residents and businesses that wish to *own* solar photovoltaic or other local renewable power.[11] CCA and H Bonds remove major barriers to customer ownership of solar photovoltaics and green power technologies. By eliminating the need for up-front capital, the CCA Program can offer the opportunity to own photovoltaics to all customers. A key question is whether eligibility will be limited to customers who own new, un-shaded flat or south-facing rooftops. This CCA Program Report examines City solar programs as well as other comparable programs in the U.S., and *recommends offering all customers the opportunity to own shares in neighborhood photovoltaic arrays, and receive the benefits of ownership on their monthly electric bill.*[12]

We also explore the potential of selling City-owned solar photovoltaic capacity to the CCA. LPI undertook a Best Practices Survey of other green portfolio programs around the United States, comparing them to, and providing precedents for, key elements of the City's CCA and H Bond Program. We recommend offering financing and ownership options to renters (who own no rooftop), and building-owners with non-optimal rooftops that would otherwise be excluded (north facing, shaded, old) in order to accelerate the uptake rate by participating CCA customers who might want to own solar power. Thus, in addition to the options of hosting and purchasing benefits from hosted systems such as blackout protection[13] or sharing facilities,[14] ratepayers would have the option to own shares and receive economic benefits from a Community Solar facility in their neighborhood or somewhere in the City.

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[10] SFPUC staff asked in the Feb 11, 2009 comments that Local Power propose changes to zoning, however, this is outside the scope of this report. Local Power did point out where changes to zoning might be useful, such as with wind power, and suggested initiating processes to make these changes.

[11] SFLAFCO's 2005 Nixon Peabody study of the use of H Bonds to augment the CCA Program confirmed the legality of using H Bonds to finance both publicly and privately owned facilities.[11]

[12] This section references a recent program designed by LPI at Sacramento Municipal Utility District (SMUD) based on a similar program in Washington State.

[13] Draft CCA Implementation Plan, p.43

[14] Draft CCA Implementation Plan, pp.114-16.

Introduction

The City's leaders recognize the need to provide prospective CCA Suppliers with detailed information about the "landing strip" when rolling out what will be a major new City- and community-owned green power infrastructure. The Draft CCA Implementation Plan outlined a method of streamlining permit and government processes in order to facilitate the 360 MW rollout.[15] The ability of a CCA Supplier to plan for and achieve the required RPS acceleration and rollout will depend in part on CCSF's assistance in using its special CCA access to confidential energy usage data and its permitting authority for the following purposes:

- CCA Program resource planning,[16]
- identifying and contacting candidate sites
- establishing streamlined processes of facility approval, permits and construction to expedite the overall process.

As renewable technologies are location-sensitive, coordination is required in which CCSF will play a critical role. Speed is of the essence – fewer delays in acquiring rooftops or securing permits for a variety of green power facilities will mean more scheduling certainty for bidders, reducing the cost of the resulting power generation.

Speed is a key component of San Francisco's program because debt service on the H Bonds will be limited to projected revenues within the duration of a proposed CCA Service Agreement. Ordinances 86-04 and 147-07 both require that the supplier commit to structured rates while achieving the RPS. Accordingly, "revenue adequacy" for bond support is a time-sensitive undertaking. In order to support a bond through the CCA contract while maintaining competitive rates, the rollout must be completed by a certain date.[17] While the Draft CCA Implementation Plan does not establish an *a priori* limit to the duration of its CCA contract, a 20 year or shorter term will dictate a front-loading of the rollout in order to be financially viable.

To avoid excessive rate impacts, the 360 MW should be online within approximately four years after initiation of service. The CCA Implementation Plan does not impose a firm rollout period but estimates three-years for implementation.[18] If, as suggested by MBMC, a longer agreement such as 25-40 years were accepted in order to build the 51% RPS

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[15] Draft CCA Implementation Plan, p.118
[16] California Public Utilities Commission Decision 04-12-046, December 15, 2004, p.47, etc..
[17] Ordinances 86-04 and 147-07 require the new CCA service to include a 360 MW rollout, which is expected to be primarily or exclusively financed by H Bonds. The bonds would be issued by the City over the same period as the infrastructure is built.
[18] Draft CCA Implementation Plan, p.34.

infrastructure,[19] this rollout would need to be completed during the first eight years.[20] The "revenue robustness" of the prospective CCA Supplier's plan would depend on revenues generated by H Bond financed facilities during the period of the agreement. As the financing/owning/governing arm of a public/private partnership, the City and County should ensure an expedited, streamlined and well planned rollout process.[21]

This CCA Program Report, and the Program Basis Report of which it will ultimately form a part, is intended to prepare the field of options and enrich the data-sets of prospective CCA Suppliers such that key issues are considered and, to the extent possible, resolved by the time that the CCA RFP is completed. *Time is of the essence for the CCA Supplier.* In order to repay H Bonds for the initial rollout while also earning a profit, the CCA Supplier will plan its rollout based on a limited schedule of revenues. These revenues will be derived from monthly electric bills minus the City's H Bond debt service, which will have first priority, making the CCA Supplier's monthly revenue risk dependent on the successful implementation of its rollout. The H Bonds must be fully replenished by CCA revenues within the term of the CCA Agreement, and CCA RFP respondents must demonstrate a substantial preparedness and commitment to accept major development liabilities in return for a long-term Power Purchase Agreement with the electricity ratepayers in San Francisco. [22]

In Local Power's opinion, the 51% Renewable Portfolio Standard required by the Draft CCA Implementation Plan[23] will only be partly achieved by the initial 360 MW rollout [24],

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[19] Michael Bell Management Consulting (MBMC) Report to SFLAFCO, May 23, 2008, Recommendation #9, p.18

[20] According to the Draft Implementation Plan, if the opt-out rate exceeds 10% of load, the 360 MW rollout requirement will be reduced in proportion to the opt-out rate, but the 51% RPS will hold for the portfolio of all CCA customers. Thus, whatever the opt-out rate, a debt service schedule will dictate that new resources be installed and generating CCA power as early as possible.

[21] The CCA Agreement and H Bond authorization must each be approved by the Board of Supervisors by ordinance, as per Ordinances 86-04, 147-07 and 146-07.

[22] Calculating the cost and annual revenue requirement is outside the scope of this report. Whatever amount is required will have to be taken from the revenue stream of bill collections, primarily from the amount specific to energy supply— which only a portion (somewhat over half) of the total customer bill. It is important to realize that this is not equivalent to a "rate increase", since the bond payment is supplying a significant portion of the CCA's electricity and thus displaces other energy sources that may or may not have similar costs to the bond repayment. The effect on rates will be a function of the differential between the cost of energy that is displaced and the cost of the bond-financed energy supply. Developing models of this proposition will be a proper task for the Program Report.

[23] Draft CCA Implementation Plan, Exhibit 2-2, p.37.

[24] The 360 MW Rollout likely represents near half the projected capacity required to meet the peak CCA demand (in Megawatts). The amount of energy that this capacity produces (in kilowatt-hours), is in Local Power's opinion, likely to be much smaller than half the CCA's electricity supply. This is principally due to the relatively low capacity factors of solar and wind energy that make up 185 MW of the supply. For example, a 150 MW wind farm operating at 30% capacity factor would produce 394 gigawatt-hours, or about 9.8% of the CCA's projected energy consumption of 4,000 gigawatt-hours; and 25 MW (ac) of photovoltaics generating 1350 kilowatt-hours/kilowatt would produce about 34 gigawatt-hours, or about 0.8% of the CCA energy supply. It is difficult to predict the capacity factors of the distributed generation components, as this depends on the resource choices that are deployed. However, even if it produced at 80% capacity factor it would generate 505 gigawatt-hours, or 12.6% of the CCA supply. Combined these would contribute 23.2% of the CCA's electricity, using the assumptions above. In our view, there is no

which will itself provide up to 25% of power consumed annually by the San Francisco ratepayers expected to participate in the CCA. [25] To achieve a 51% RPS by 2017, suppliers who do not elect to build the renewables will have to buy green power or credits, potentially at a premium. Any cost of service impacts will appear on their rate schedule, affecting their competitive position. Thus there is a strong incentive to propose a Phase II rollout scenario, in which the full 51% RPS infrastructure is financed and built for the CCA, in addition to the required 360 MW rollout. This would lower the long-term RPS compliance costs. Thus, the required H Bond authorization for the Phase II rollout could be achieved by either:

- a second H Bond issuance enabled by extending the initial CCA Service Agreement to support the additional investment
- (as proposed by MBMC) a 25-to 40-year contract duration to achieve the entire 51% RPS objective using a single CCA Service Agreement and a single H Bond authorization of the Board of Supervisors.

This Report contains an initial survey of opportunities and obstacles for prospective CCA Suppliers to meet a higher standard of performance on the rollout with more competitive electricity rates. The Program Basis Report will provide a foundation on which prospective CCA Suppliers may prepare and propose a credible and competitive rate schedule and rollout plan. A successful RFP process will depend on CCSF and SFLAFCO providing a data-rich RFP package so that prospective CCA Suppliers can work productively with City agencies.

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scenario where the wind, solar and DG resources of the 360 MW rollout could contribute 50% of the CCA's electricity supply, though successful efficiency, conservation and peak demand reduction programs would tend to increase the percentage share that these renewables contribute.

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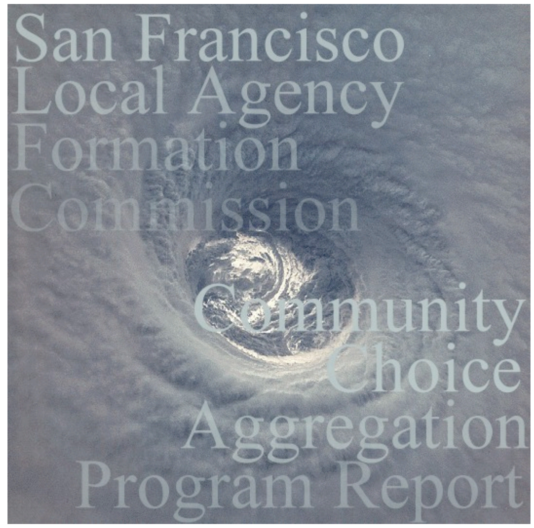
Our Approach



Contributors for LPI include Paul Fenn, Robert Freehling, Howard Golub of Nixon Peabody, Bill Powers of Powers Engineering, Mike Marcus, and well as Bradley Turner and Joe Speaks from Booz Allen Hamilton. Michael Kuchkovsky provided architectural photosim images, and David Erickson assisted with editing the final version. Important contributions from City agencies were made by Assistant General Manager Barbara Hale and Regulatory and Legislative Affairs Manager Sandra Rovetti of the SFPUC, Cal Broomhead and Johanna Partin of the Department of the Environment, Deputy City Attorney Theresa Mueller, Chief Building Inspector Laurence Kornfield, and Craig Nikitas, Senior Planner at the City Planner's office. Nancy Miller provided substantial input and assistance in the preparation of this report. This report incorporates comments and feedback from SFPUC, SFLAFCO and San Francisco Department of Environment (SFDOE) staff. [26]

Based on these contributions and others, LPI has conducted research and analysis with the intention of identifying ongoing energy projects for possible inclusion in the CCA Program. LPI has also evaluated benefits of complementary government programs to the CCA Program, and has evaluated each identified project for inclusion in the CCA Program scope. Such factors were considered as technical integration, overall implementation time requirements, and whether there would be any significant siting and/or permitting issues. Ongoing City energy projects or programs that may potentially impact or work constructively with the CCA Program were also considered, with respect to: (1) use of common funding sources; (2) jurisdiction and ownership issues; and (3) technical or business interface issues.

[26] LPI has held several meetings with LAFCO staff, SFPUC staff and SFDOE staff, in person and by conference call, to present the initial draft report and to discuss any recommended revisions. Specifically, this Final Draft incorporates input from SFPUC staff on a First Draft submitted to SFLAFCO on September 22 and subsequently circulated to SFPUC staff and presented by Local Power for their comments. Similar review and comments were solicited and received from SFDOE staff, and this feedback was incorporated into the report.

LPI met with staff from the SFPUC and other City departments determined by LPI to be necessary for its work, such as the Department of the Environment or other energy-related departments. LPI submitted a list of questions to the San Francisco Public Utilities Commission Power Enterprise Division.

[29] Draft CCA Implementation Plan, p.93.

2. Major Conclusions

This report arrives at a number of major conclusions about opportunities, barriers and technical issues presented to the CCA program by ongoing energy developments. Most significantly, the report identifies at least 156 MW of additional, clean energy opportunities that we recommend for inclusion in the CCA portfolio *in addition to* the 360 MW of renewables and demand-side capacity development already required as part of the new service by adopted City policy. If included, these new elements will increase the potential CCA resources from 360 MW to over 500 MW of local and regional capacity. These additional resources can reduce the overall CCA portfolio cost, reduce the exposure to wholesale power market volatility, and enhance energy independence. Some of the more important conclusions are:

- **We recommend that development of 106 MW of new Cogeneration potential identified by SFDOE report * be added as a component of the CCA program.** Opportunities for cogeneration should be explored in more depth, the economic potential verified, and additional potential not included in SFDOE report investigated. SFPUC boiler retrofit program should be expanded to SFDOE so that CCA customers can develop cogeneration. The City should evaluate the interest of existing boiler operators to participate in the CCA program. LPI recommends that cogeneration be *additional to* the 72 megawatts of distributed generation in CCA Phase-I Rollout, as it is in the City's Energy Resources Plan.

- **An urgent directive is needed to petition the California Public Utilities Commission to allow CCSF to administer Energy Efficiency Public Goods Charge funds to help implement the CCA's 107 MW efficiency/demand reduction program.** SFDOE's Energy Efficiency program is in process of being renewed. CCSF should make appropriate changes to the PG&E Partnership for energy efficiency by resolution of the Board of Supervisors. A schedule should be adopted for a seamless transition for SFDOE staff to the new CCA funding stream, so that SFDOE services are not interrupted by delays or funding gaps.

- **We interpret the Raker Act to allow an estimated 20 to 40 MW of inexpensive Hetch-Hetchy capacity to be made available to San Francisco residential and business ratepayers.** This power would be supplied through the CCA portfolio, if available, consistent with priorities set forth in the Raker Act. We propose using a "split delivery" mechanism to structure the transaction in a manner consistent with the Raker Act.

* *An Assessment of Cogeneration for the City of San Francisco,* SFDOE report by Dr. Philip M. Perea, June 2007.

- **The CCA can take advantage of increased flexibility for ownership and energy transactions with potentially over 85 MW of future local solar photovoltaic capacity.** The CCA Program should offer all ratepayers the right to purchase ownership-shares in Community Solar Arrays and receive economic benefits on their electric bill. Electricity generated by SFPUC renewables, including from solar energy, could be legally transferred to San Francisco ratepayers through the CCA. This transfer could be structured through power purchases and/or swapping agreements.

- **The 400 MW Trans-Bay Cable can supplement the ISO transmission system to provide access to renewable energy resources required by the CCA Program**. This could help make using the Delta wind resource an option for the City's wind farm. FERC rules give renewable energy resources high priority for transmission access. However, the City will need to coordinate its efforts in a timely manner to avoid potential future costs for grid upgrades, and to insure access to transmission capacity.

- **Significant progress has been achieved in improving the permitting and zoning process for solar photovoltaics, but further changes are needed to prepare for the 360 MW rollout.** These include potential legislation to streamline San Francisco's zoning and permitting procedures and rules for renewable distributed generation, including a recommended zoning overlay raising the height restriction on urban wind from 90 ft to 250 ft in certain Commercial and Industrial zones of the City**.**

- **We report on programs in other U.S. cities and utilities with "Best Practices" that can be applied to the CCA program.** These include precedents for Community Solar projects, and public purchase of local solar green credits. Such programs can lower the cost of solar energy and increase access as well as participation by the public. Existing programs help to establish the viability of elements of the CCA Plan and can provide guidance on implementation.

- **We recommend additional measurements of the Golden Gate Tidal resource at optimal locations.** SFPUC/URS, EPRI, and US Navy studies raise questions about the potential economics and scale of development. The 1 to 2 MW mean usable resource found by URS might allow construction of a tidal facility significantly larger than the 1.2 MW facility proposed by URS, with lower energy cost. Other opportunities for lowering cost should be explored. There should also be an investigation of a potential renewable-only transmission line to the Golden Gate site.

3. CCA Customer Access to Hetch Hetchy Excess Capacity

The Draft CCA Implementation Plan provided that the SFPUC "may provide renewable capacity and/or energy, including its Hetch Hetchy assets,"[29] to the CCA Program. Concern has been expressed that Section 6 of the Raker Act would prevent the CCA program from integrating Hetch Hetchy power into the community's portfolio. Local Power has identified a means of ordering delivery of Hetch Hetchy power to San Francisco ratepayers, and has developed a transaction mechanism which we believe will make it legal for participating San Francisco residential and business CCA customers to pay for and receive the benefits of Hetch Hetchy power under the Raker Act.

- We propose a "split delivery" transaction for the CCA to allow Hetch Hetchy power to be available to CCA customers under the Raker Act.
- Using its rights to transmission under the Federal Power Act, the City could have Hetch Hetchy power delivered to the City's end-use customers
- The end use customer would have two supply sources: Hetch Hetchy plus the supplier's portfolio, structured to be transparent to the end-use customer and revenue-neutral between the City and Supplier
- Access to Hetch Hetchy power will require further analysis, including of legal options.

Potential Benefits of Hetch Hetchy power to CCA Program. Hetch Hetchy power is defined as non-renewable hydropower under state law, but is a relatively clean, existing, low-carbon, energy resource that, if included in the CCA portfolio, would lower the overall cost of service to San Francisco's CCA customers, reduce the CCA's wholesale procurement burden, and improve the overall economics of San Francisco's accelerated renewable portfolio. SFPUC staff initially estimated that up to 70 megawatts of power capacity might be made available to a CCA, but later stated this to be in the range of 20 to 40 megawatts.

Low Cost Power. Including Hetch Hetchy capacity in the CCA resource portfolio will lower overall portfolio cost for the CCA program. While the exact amount varies greatly by customer, retail rates paid by Hetch Hetchy customers can be as low as three (3) cents per kilowatt hour, compared to average PG&E retail rates of 13.1 cents per kilowatt-hour in 2008.[30] The actual cost of the hydroelectric generation is only 1.517 cents per kilowatt-hour. [31] *Hetch Hetchy hydropower presents an opportunity to enhance the performance of the CCA Program's planned portfolio to balance the intermittent electric generation and higher cost of renewable sources.*

[30] Utility-wide Weighted Average Retail Electricity Prices, Excel Spreadsheet, California Energy Commission, http://energyalmanac.ca.gov/electricity/Utility-Wide_Average.xls
[31] This cost is at the busbar, and thus excludes transmission and delivery of power, as reported in the Hetch Hetchy Power Sales Agreement between CCSF and Turlock Irrigation District, Mar. 26, 2008.

Clean Power, Locally-Owned. Much cleaner than coal, nuclear or even natural gas generation, Hetch Hetchy power can reduce the air pollution and climate impacts of San Francisco's CCA power supply.

Energy Independence & Rate Security. Including Hetch Hetchy power in the CCA portfolio will reduce the amount of power that must be procured on wholesale power markets in order to meet local demand. This would enhance the energy independence of San Francisco's economy, help protect consumers against volatile wholesale power markets, and achieve the intent of the Raker Act, which promised low-cost hydropower to San Franciscans nearly a century ago.

Technical Issues. Currently, access to San Francisco's share of Hetch Hetchy power is limited to a pool of City agencies and special customers that are eligible to receive the power across PG&E's lines according to the City's Interconnect Agreement. However, certain non-City private sector customers are now receiving Hetch Hetchy power. Special categories of private sector customers – such as the JCDecaux Street Furniture categorization in last year's 30-year renewal of that Interconnect Agreement— have been added as third party customers, their load being treated as an "unmetered City account."[32] Similar arrangements were also made during the 1980's. It is clear from decades of transactions between PG&E and the City that Hetch Hetchy capacity is not completely firewalled from residential and commercial customers, but merely requires a transaction mechanism to provide for both physical delivery and payment.

Currently, however, transactions for Hetch Hetchy power largely exclude San Francisco residents and businesses. Regarding Hetch Hetchy, a *de facto* or presumed firewall has separated most San Franciscans from enjoying the benefits of their federally mandated Hetchy power since the dam was built in 1923. Currently, any excess capacity from Hetch Hetchy not consumed by City Agencies and "unmetered accounts" (private sector San Francisco ratepayers), must be sold to two Central Valley irrigation districts serving the Modesto and Turlock regions. This treatment is no longer necessary given the CCA Program's specific mandate of providing power to PG&E electricity customers in San Francisco, as well as fairly recent federal transmission access laws and regulations.

Local Power proposes using existing federal laws and regulations in conjunction with CCA to provide San Francisco customers a retail channel to receive the benefits of Hetch Hetchy power, using a "split delivery" mechanism that would enable the power to be sold directly to a CCA customer. Thus, the SFPUC may finally convey this historic public resource to benefit any San Franciscan who elects to receive it by participating in the CCA program.

Initial Legal Analysis. Section 6 of the Raker Act in essence prohibits San Francisco from selling the water or electricity from Hetch Hetchy to "any corporation."[33] The history of the Raker Act shows that Congress' intent was that the people of San Francisco, not private corporations such as PG&E, should receive the benefits of Hetch

[32] Agreement Between Pacific Gas & Electric Company and City & County of San Francisco, 2007, p.4.
[33] United States v. City and County of San Francisco 310 U.S. 16 (1940).

Hetchy. However, the City can and does arrange for the transmission of Hetch Hetchy power to customers of CCSF. CCSF has had a series of such arrangements (using PG&E as the transmitting entity) on file with the FERC for decades. The City should be able to enter into a similar arrangement with its Supplier without violating the Raker Act. If transmission services are required, either the City or the Supplier should be able to require PG&E to provide transmission service pursuant to the Federal Power Act and Open Access Transmission Tariffs filed thereunder. However, a transaction mechanism is needed to allow for San Francisco CCA customers to receive and pay for the benefits of Hetchy Hetchy power on their electric bill.

Local Power's Proposed "Split Delivery" Transaction Mechanism. The preliminary review of the Interconnect Agreement also indicates that it should be feasible to structure a similar arrangement with the Supplier insofar as Raker Act compliance is concerned. Nonetheless, SFPUC Assistant General Manager Hale has expressed concern whether the transaction could be challenged as not complying with the Raker Act, and that concern must be carefully considered. CCA also potentially provides the City with an alternative method of compliance with the Raker Act, which has not been available in the City's dealings with PG&E.

The City may use its rights to transmission under the Federal Power Act, to have Hetch Hetchy power delivered to the City's end-use CCA customers. Under this arrangement, the end-use customer would have two supply sources: Hetch Hetchy, and the Supplier's portfolio; together these meet the customers' full requirements. Properly structured, the "split-delivery" would be transparent to the end-use customer and revenue neutral between the City and Supplier. *In order to confirm the feasibility of this approach, LAFCO should pursue a legal opinion to determine the amount of, and options for accessing, excess Hetch Hetchy capacity for residential and business ratepayers.*

SFPUC Comments. In its comments on our initial draft of this report, SFPUC appears to concede that Local Power's proposed transaction mechanism would suffice to overcome Raker Act barriers, which if true would put to rest a decades-old barrier to bringing Hetchy power to San Franciscans. However, SFPUC also pointed to its recently renegotiated Interconnect Agreement with PG&E as being the new barrier. "The draft report significantly understates the difficulty that CCSF has had under the existing PG&E IA (Interconnect Agreement) to extending Hetch Hetchy electric generation beyond city load. The draft report incorrectly describes this limitation as an 'unspoken' firewall that 'is not really firewalled.' Under the Interconnection Agreement with PG&E, CCSF is limited to only serving 'municipal load.'" SFPUC also remarked that the JCDecaux example involves public toilets, which constitute a "municipal function," which appears to be their justification within the existing Interconnect Agreement.[34]

[34] SFPUC's Initial Comments on "First Draft SFLAFCO CCA Program Report (v. 1.5)," p.15.

Apart from our use of the term “firewall” which is meant as a characterization, not as a legal description, the important point to observe is that Hetch Hetchy could serve non-municipal load (CCA residential and business customers) using CCA and FERC regulations but that it must either do so either under a separate Interconnect Agreement, or else the existing Interconnect Agreement could be *amended to expand or remove restrictions*. *It is typical in interconnect agreements that both parties can apply to the FERC for changes if parties cannot agree. Restrictions in the existing Interconnect Agreement do not prevent the City from securing its federal Open Access rights.*

In short, the existing Interconnect Agreement does not prevent San Francisco from implementing the CCA Split Delivery/Open Access option we have proposed. PG&E has a requirement under FERC regulations to provide open access, and to provide an IA and Wholesale Distribution service to the City according to FERC regulations. Even though the existing agreement does not *currently* provide for serving CCA customers, the City still has the federally mandated legal option of demanding the service from PG&E. We see no basis upon which PG&E could refuse to provide the new service, irrespective of its current Interconnect Agreement with the City.

Implementation Time Required. FERC has in place established mechanisms that require PG&E to either reach agreement with the City, or if agreement cannot be reached in a short time frame, to file an “Unexecuted Interconnect Agreement” with FERC, which has authority to ultimately determine the appropriate terms and conditions. Under FERC regulations, once an eligible applicant demands the service, PG&E must respond within a period of *months, not years*; if no agreement occurs (either no PG&E response or unreasonable conditions) the applicant may apply to FERC for an *order*. FERC has an enforcement staff hotline whose job is to prevent transmission owners from using delay to deny service to competitors. Federal Open Access rules are specifically designed to prevent such delays. Thus, while the exact timeline of delivering the power to San Francisco CCA customers is hard to predict precisely, resolution of the issue should be achievable within the CCA Program’s late 2009 to early 2010 implementation timeline, provided that sustained and effective efforts are undertaken by the City with alacrity.

There are several factors that might impact how promptly Hetch Hetchy power could be made available to the CCA Program. LPI has preliminarily reviewed the City’s 2007 Interconnect Agreement with PG&E. This lengthy document (over 100 pages, plus 31 appendices) could impact the utilization of Hetch-Hetchy power. The potential for disputes in interpreting the 2007 Agreement is underscored by the fact that the City and PG&E were in litigation over the Agreement until late 2008. Given the importance of ensuring full compliance with the Raker Act, the complexity of the 2007 Agreement with PG&E, and the potential for litigation, *LPI recommends an in-depth analysis of these issues to confirm the availability of this power for CCA customers.*

4. Projects Identified for Possible Inclusion in the CCA Program

This section covers a number of ongoing and potential City Renewable Generation Projects such as the Golden Gate Tidal project, as well as wind and solar projects, as described in the CCA Implementation Plan (IP).

a. Golden Gate Tidal Power Project

The Golden Gate tidal resource is a potential local resource for helping to meet the City's adopted 51% RPS requirement. Recent studies by EPRI, URS [35] and the US Naval Postgraduate School have reached divergent conclusions regarding the Golden Gate tidal resource. LPI has reviewed these reports and evaluated them in light of the unique variables of the CCA program. The mean usable resource estimate by EPRI was 35 megawatts, and they concluded that power from the tidal current could be competitive with conventional power from the utility. URS, using a far more developed model, concluded that the mean usable resource was only 1 to 2 megawatts and that the cost to tap this power could range from 80 cents to well over $1 per kilowatt-hour.

- Resource estimates range 12 MW to 237 MW; 10% to 15% considered usable: URS said 1-2 MW, EPRI said 35 MW.

- EPRI: Simplistic tidal model overstated resource and underestimated likely cost, but better implementation and financial model.

- URS: Sophisticated, much more accurate and comprehensive computer model for currents, but financial and deployment model may overstate cost.

Recommendation: City should obtain better Doppler data for optimal sites. Seek to lower cost: better sites, opportunities to scale up, low or zero cost financing, CCA market. Evaluate options for cable to Golden Gate.

It appears that EPRI greatly overestimated

[35] At the December 12, 2008 SFLAFCO meeting, Barbara Hale presented Local Power and Commissioners a letter, dated six weeks earlier on October 30, 2008, from SFPUC consultant URS containing comments on the initial working draft of this document, which Local Power had shared with Ms. Hale for comments. Though the URS letter was delivered late and just 19 days before expiration of the contract for this report, we reviewed the letter *pro bono*, and made significant changes in the presentation of the tidal resource in this Final Report. The URS comments did not challenge, nor did LPI substantially alter, our primary recommendations: 1) that there should be further investigation of the tidal resource, and 2) that the City should examine options for reducing the cost (such as low cost financing, or determining if the resource can be developed at a somewhat larger scale than the URS report suggested) At no point did Local Power challenge URS's fundamental resource assessment, or use EPRI's overestimate. This was an apparent misunderstanding by the URS commentator, and a point that was perhaps not sufficiently clear in the first rough draft. This final report attempts to clarify that Local Power was not, and is not, disputing URS's tidal power resource estimate, but in fact is relying upon it.

the mean usable resource, and that URS is likely much closer to the truth on this point. However, there are important considerations that may allow development of the Golden Gate as a reasonable, though likely modest, source of local energy for the CCA.

Golden Gate Tidal Resource

The entire Central Valley water system, the Sacramento, San Joaquin, Stanislaus, American and other rivers, drain through the delta, and into the Bay. The Bay itself is a large reservoir that holds the tidal flows that go in and out twice each day. The combined tidal flows and river currents are concentrated through a relatively narrow opening to the sea at the Gate.

Studies have been performed to determine whether this movement of water would be adequate to generate electricity in significant quantities and at competitive prices. These reports show considerable divergence of estimates on the availability of tidal energy in the Golden Gate. Should harnessing tidal power prove to be cost-effective, the Golden Gate tidal resource could be a potential resource for contributing to the City's 51% RPS requirement by 2017. For various reasons, tidal technology is *not* envisioned to be part of the 360 MW Phase I deployment.

Local Power examined three studies on Golden Gate tidal energy. These reports came to different conclusions about the available and usable resource, cost and performance of tidal generation at the Gate. The determination of whether tidal power is in fact viable depends partly on measured total resource, but also on other assumptions such as:

- What fraction of the resource is usable without disturbing the bay
- How large a facility is available or proposed to tap the resource
- Where the facility is located relative to the currents
- The type of financing used
- Future cost and performance of tidal generation technology

Alternate assumptions can lead to very different results, even for the same tidal resource.

Analysis of the EPRI Report

The first of these reports, by the Electric Power Research Institute, was conducted in 2005 as part of a much larger study that examined a number of potential locations around the US that seemed promising for tidal power. An entire report was devoted just to developing the methodology that would be used in all the analyses, and considerable attention was paid to an inventory of different technologies and their performance. The economic model was also sophisticated, with assumptions clearly laid out in spreadsheet tables, taking into account tax credits, different financing assumptions, the value of accelerated depreciation, etc.

In contrast to the robust financial analysis, the assessment of the tidal resource at the Gate was based on a relatively simple mathematical model. A line was drawn on a map 500 meters upstream of the Golden Gate Bridge which goes through a NOAA buoy. The buoy is used as the primary source of actual measurements for tidal current velocity. The authors then measured the length of a “transect” line that crosses the Gate at the narrowest point, very close to the bridge. The lengths of the two lines are mathematically each multiplied by the average water depth of the bay under the lines. The product (result) gives an area through which the water must pass under each line. The authors conclude that the area through which the flow volume must pass at the buoy is 1.87 times the area at the Gate. From this calculation they conclude that the water velocity must be 1.87 times what it is at the buoy.

From time differentiated measurements at the buoy, the EPRI report produces a distribution table with 25 velocity rates that shows how much power is produced at each velocity over the course of a year. The 25 velocity resources are summed up to give a total average tidal resource of 237 megawatts, at an area rate of 3.2 kilowatts per square meter. They consider 15% of the resource to be usable without disruption to sea lanes or the ecosystem of the Bay, which amounts to an average output of about 35 megawatts and a peak of 100 megawatts.

One problem with this method is that it assumes that water velocity at the buoy is typical of water velocity though the entire cross-section, even though no measurements have verified this. The authors confess that the properties of the body of water are not likely to be “linear”, meaning that the actual flow of water will exhibit different flow rates at different parts of the cross sections and at different points in the stream. They also recommend a more detailed resource assessment be carried out to account for these effects. It is likely that the EPRI model for the current is inaccurate, and measurements made in the bay appear to confirm this.

EPRI examines two technologies, Lunar Energy’s 1.11 megawatt RTT 2000 and the Marine Current Turbine 1.28 megawatt SeaGen. They give extensive descriptions, with cost and performance analysis for each one.

EPRI’s report recommends building a demonstration facility of just over 1 megawatt, projected to operate at a capacity factor of 33%. They conclude that the capital cost will be about \$5.6 million, but do not give a cost of electricity from that plant. Using similar assumptions as the EPRI report, but not considering tax credits or other subsidies that they include, LPI derived a straight cost of 36.2 cents per kilowatt-hour. Obviously this is far too expensive for commercial operation, but the EPRI authors state that commercial operation is not the point of the facility, only to demonstrate the resource and technology potentials.

Building to larger scale could reduce the unit costs. EPRI’s commercial plant is 44.5 megawatts total capacity, though its average production is much lower than this. The unit cost drops from \$5600 per kilowatt in the demonstration unit, to about \$2000 per kilowatt. The larger plant also benefits from economy of scale for operation and maintenance.

The cost of energy depends heavily on the cost of financing and profit. In the EPRI models both the utility-owned and non-utility owned (third party) average cost of financing plus equity is about 11%, whereas a publicly owned facility—such as a municipal utility or CCA— would be financed on a 20 year bond at 5% interest. The nominal cost of electricity, under their model, comes to 7.6 cents per kilowatt-hour for utility owned tidal plant, and 5.6 cents per kilowatt-hour for a municipal utility or CCA. Both of these are considered to be competitive with other existing power supplies.

It is important to analyze some of the assumptions in the EPRI financial model. To arrive at this low cost of energy they factored in revenue from three sources:

- <u>Sales of renewable energy credits at 1.5 cents per kilowatt-hour.</u> This is possible, but it would mean that a CCA or any other power purchaser would not get the benefit of the "green value" to count toward their renewable energy portfolio. In addition, this is a retail rate for green credits, rather than a wholesale rate which is closer to 0.5 cents per kilowatt-hour. A generator would typically get a wholesale rate, with a green credit reseller marking up the price for consumers and taking a profit.

- <u>Federal tax credits or renewable energy payments.</u> Federal tax credits of about 2 cents per kilowatt-hour are given to private developers of renewable energy facilities for the first ten years of operation. Unfortunately, these credits often expire and are unavailable. This creates some development risk, as the builder will have to decide if the project can be built inside a year where the tax credit applies. CCAs and municipal utilities are non-profit organizations that do not pay tax, and thus cannot take tax credits. To account for this fact, congress set up a special payment for renewable generators built by public power agencies. Unfortunately, the account that pays for this program is rarely funded. [36]

- <u>Accelerated depreciation</u>. This is a benefit for tax paying entities that can take the write-off against their tax liability, but any profit from the tidal generator or other sources is also taxable. Thus the tax issue can be complex. Accelerated depreciation can be a real benefit for businesses and investors, but its use to calculate the cost of power is sometimes controversial, especially as it is not the same as a tax credit that would be taken in the first year.

A more direct calculation of cost of energy, not considering tax subsidies or special "green credit" payments, yields higher cost of energy values: 13.8 cents per kilowatt-hour

[36] The recent federal economic recovery legislation will in certain circumstances make direct payments for entities that cannot take advantage of a tax credit.

for an investor owned utility, and 9.8 cents per kilowatt-hour for a public entity like a municipal utility or CCA. Either of these could be justified by the fact that they would provide green energy. The EPRI deployment model showed 129 gigawatt-hours per year of generation, and even this high estimate would represent only about 3% of the City's electricity supply.

Analysis of the URS Report

The second report is by URS, a major engineering firm. Their analysis leads to essentially the opposite conclusion as the EPRI report, namely that the tidal resource is very small, eight times smaller than what EPRI estimated, and development of the Golden Gate tidal power is for all practical purposes economically infeasible.

The divergence of the EPRI and URS results is interesting, particularly considering that the two reports share a number of common assumptions. For example, both reports refer to the same government data, from the NOAA buoy 500 meters upstream from the bridge, which represents a primary reference measurement set in both models. They both applied the same mathematical law for the tidal currents, i.e., that power of the current is proportional to the cube of velocity. Both had similar accounts of the semidiurnal, diurnal and monthly cycles.

Both also had similar data for characteristics of tidal generators, and what they would cost if built to different scales. Both also had roughly similar assumptions about operation and maintenance costs.

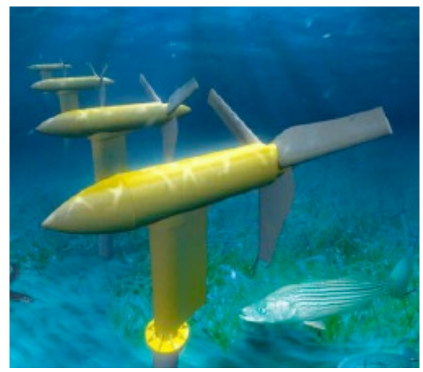
However, URS had a few key differences with the EPRI study. By far the most important was the assessment of the tidal resource, which significantly changed the results. The report relied on a peer reviewed computer model using 2.2 million points of reference in the Bay, taking into account assumptions about water flow from the delta and tidal flows in and out of the Gate. The model was calibrated to tidal measurements in some parts of the bay using Acoustic Doppler Current Profilers (ADCPs). [37] URS came up with a figure for the tidal velocity at the Gate that was ½ of what EPRI had. As a direct result, the

[37] URS in its letter objected to Local Power's recommendation in the earliest draft that "real world measurements" need to be performed. We agree that this did not adequately characterize either URS's method, or what Local Power intended to convey, and have changed the description. To be more exact, real measurements of tidal currents have been made, however many of these measurements are at other locations than where tidal current generators would either likely, or optimally, be placed. In addition, some of these are for periods of time that may not accurately characterize the resource. Such data are "real world", useful, and necessary for calibrating computer models; however, it is important to note that the model—even after calibration—contained significant deviations from the real world data URS used. This was not a weakness of their report, since they state this issue explicitly, but it is an important limitation of their model. Unfortunately, URS seems to have confused our critique of the *model* they used as being a critique of their *report*, which was never intended. Every model has limitations, and we were simply attempting to convey in summary form to policymakers the limitations of the model that URS had pointed out in its own report (and confirmed again in their letter). Hopefully this final report makes the distinction more clearly. In any case, Local Power can assure URS that we are certainly aware of Acoustic Doppler Current Profilers and that real world measurements were used to calibrate their model.

value for power resource was the cube of the velocity difference, or 1/8th the power. While 1/8th of the ERPI total power resource value would be about 30 megawatts, URS provided an even smaller estimate of 12 to 15 megawatts. URS also stated that only 10% of the resource would be usable without disrupting the Bay system, while EPRI believed that this could fall into a range of up to 15%.

The report then examined only the possibility of a single tidal generator unit of 1.2 megawatt, located east of the Gate on an elevated section of the Bay floor. At this size, the deployment of tidal units would lose all benefits of economy of scale, and the consequent cost of electricity was estimated to be 80 cents to $1.40 per kilowatt hour, assuming an 8% annual cost of money. This leads URS to the conclusion that tidal power in the Golden Gate is clearly uneconomic.

Recommendation on Golden Gate Tidal Power Plant.



In general, LPI finds the tidal model used by URS to be a useful tool that is much more powerful and well tested than the EPRI model. However, we find three points raised by the URS report that suggest the possibility of a larger development potential and lower cost energy than would be supplied by their proposed 1.2 megawatt facility:

1) While showing a mean usable resource of 1 to 2 megawatts, they deploy a 1.2 megawatt generator which is reported to operate at 11% capacity factor. Thus the mean operating capacity is only about 130 kilowatts [38], at least 10 times smaller than what could be developed given the resource that URS found to be usable. The 1 to 2 megawatt mean resource should allow deployment of at least 5 to 10 megawatt facility.

2) The URS report—unlike the EPRI report— did not show the potential for using low cost financing, which is a specific instrument available to a CCA that could lower the cost of energy from a tidal plant.

3) According to the resource maps generated by the URS computer model, there were locations with significantly better resource than the site chosen by URS for their tidal facility.

LPI recommends that CCSF use current monitoring equipment to perform further analysis of the tidal resource to supplement the measurements and models that have already been used. The aim should be to better characterize specific locations that might have the best resources.

[38] Mean output of a generator is the product of the capacity of 1.2 MW (or 1200 kilowatts) times the 11% capacity factor, yielding a mean output of only 132 kilowatts. The actual power drawn from the current will be somewhat higher, since conversion efficiency is not perfect.

This recommendation is partly based on analysis of the URS study, which raises significant questions. To begin with there are several limitations in the URS model that are revealed within the URS report itself. They point out that a computer test that they performed gave a lower value for tidal current than the 3-dimensional model that simulated 6-months, of 0.93 versus 0.87 meters per second. Thus the shorter simulation understates the longer simulation by the cube of speed, so the higher 6 month result would generate almost 25% more power. The report indicates that the longer term value is likely to be more accurate, and that the shorter period was not representative. They suggest that future modeling efforts take care in selecting the modeling period for this reason.

In addition, tidal maps generated by their simulation show considerably better resource exists to the west of the bridge than at the site inside the Gate where the proposed that the tidal generator be built. The best resource is a few kilometers outside the Gate; however this is near the surface and may pose special challenges for development. [39] A more usable resource is shown by the 50 meter and 70 meter depth maps, which is much closer to the bridge, just to the west. If this site were chosen, then the power resource might be even better. Since only a fraction of the tidal resource would be tapped, there is a possibility for finding specific locations with higher resource than what is indicated by the average or "mean" resource.

A limitation of both studies is reliance upon models and inadequate measured data at exactly the sites that have the best resource. A study performed at the US Naval Postgraduate School at Monterey performed measurements from the Bay floor directly at the Gate for a period of over a month. The results showed tidal energy resource that is apparently greater than what is reported by URS, though further analysis would be necessary to see if this is valid or applicable. In general, the URS study minimizes the availability and maximizes the cost of the tidal resources, especially relative to a CCA.

A measurement of the Golden Gate tidal current at the optimal locations is important. This is due to the ease with which small variables or errors in computer modeling can lead to differing conclusions. The potential value of a local renewable resource and the need to achieve City clean energy goals could make this investigation worthwhile. If tidal generators are properly located to take advantage of better resources, it is only necessary to scale up modestly to get unit savings on installed capacity. In addition, a CCA has the advantage of low cost bond financing, a point noted in the EPRI study. The URS study did not use this tool of low cost financing, which would have further lowered the cost.

There is also potential for further technology development, as URS points out in its report. In particular, individual tidal generators have increased in size over time. The initial SeaGen model was 300 kilowatts, which has been more recently scaled up to 1.2 megawatts. A larger capacity machine of 1.5 megawatts is planned in the next few years. Increasing size of turbines can significantly improve economics through lower manufacturing and operating cost per unit of output. This has been borne out in the wind

[39] In the URS letter their comment on this point assumed that Local Power was referring to the location 3 km outside the gate with better resource. This paragraph was added to clarify the discussion on this point.

industry. In addition, a larger size turbine would be able to fit into very close to the same footprint as a smaller turbine, and thus could avoid some of the siting problems associated with having to place multiple generators on the floor of the bay or tidal channel. This is especially important given the relatively small areas of optimal resource that might not allow a large number of turbines to placed in those locations.

A combination of tools will be needed to bring down the cost and increase performance of tidal power to the level where it would make economic sense in the Golden Gate. These include improvements in technology, lower infrastructure and operation costs, and low cost financing. Even with favorable factors, the resource itself appears to be small, and will likely contribute less than 1% of the CCA's electricity supply. [40] Nevertheless, as a local resource it could contribute toward the City's goals of energy independence and increasing reliance upon renewables.

Tidal Permitting Issues. Tidal power involves an extremely complicated permitting process that requires the cooperation and authority of 19 Federal, State, Regional and Local agencies. In January, 2007 the SFDOE mapped out the permitting process in a Tidal Power Permitting Matrix.[41] The matrix accurately shows that the City and County of San Francisco must play the role of applicant, not regulator, in the development process, should the CCA Program include development of this project as part of its rollout.

Tidal Power Facility Permitting Agencies[42]

In January 2007, the Department of the Environment and the CTAC Tidal and Wave Generation Committee compiled a Permitting Matrix to outline the likely agencies and government bodies who would have jurisdiction over a tidal power project. There findings indicate that the permit process(es) associated with tidal power are extensive and potentially involve 16 agencies at the federal, state and local levels.

Federal agencies include:

- Federal Energy Regulatory Commission (FERC)
- United States Army Corps of Engineers (USACE)
- United States Coast Guard (USGC)
- United States Fish and Wildlife Service (USFWS)
- National Oceanic and Atmospheric Administration (NOAA)
- Advisory Council on Historic Preservation
- Bureau of Indian Affairs

[40] For example, a 10 megawatt facility operating at 11% capacity factor would provide a mean power of 1.1 megawatt, and generate 9636 megawatt-hours. The Draft CCA Implementation Plan states that the CCA would consume 4,266,550 megawatt-hours, of which the tidal in this example would supply 0.22%

[41] See Attachment A3.

[42] Please see attached DOE Golden Gate Tidal Power permitting matrix, Attachment A3.

State agencies include:

- San Francisco Bay Conservation and Development Commission (BCDC)
- California Energy Commission (CEC)
- State Lands Commission
- Department of Fish and Game
- San Francisco Regional Water Quality Control Board
- Office of Historic Preservation/State Historic Resources Commission

Local agencies include:

- City and County of San Francisco
- San Francisco Port Commission
- Marin County

Primary CCSF staff contact:

Johanna Partin
Renewable Energy Program Manager
Department of the Environment
Phone: (415) 355-3715

Implementation Time Required. Given the number of jurisdictions and the complexity of the permit processes involved, a tidal power facility will likely take 5-10 years to permit (very rough estimate).

To facilitate the various permit processes, LAFCO should establish a Tidal Permit Working Group comprised of representatives from each permitting agency. In addition, staff resources should be dedicated to the working group and to the management of the permitting procedures. *LAFCO/SFPUC may want to hire an outside consulting group who has expertise and proven success in extremely complex tidal permitting projects in other states.*

Potential Impacts to CCA. A Golden Gate Tidal Power Plant would qualify as a renewable resource and could be financed by H Bonds along with the other renewable resources in San Francisco's portfolio. However, the facility would also require transmission in order to deliver power into the City. A number of options have been raised to finance such a transmission line, including municipal bonds or private financing. In the event that a cable is considered, the cable should be of high enough capacity that it could serve future development phases to deliver power from additional oceanic power resource development such as off-shore wind power and wave power facilities, to justify the time and resources invested in the permit procedures.

b. CCSF Solar Photovoltaics Programs

i. New Solar Incentive Payment Program

- SFPUC is allocating $2 million - $5 million/year for 10 years for solar incentives to PG&E customers. The $3000 to $10,000 cap effectively limits size of PV systems, and higher costs can offset the financial value of the incentive.
- SFPUC plans 62 megawatts of photovoltaics, most through Power Purchase Agreements (PPAs) by 2013.
- **Recommendations:** Integrate City incentives with CCA; excess SFPUC solar power may be sold to the CCA. Use tools in Implementation Plan to lower cost & enhance value of solar. CCA should include community ownership, using "portable shares" and credit customer's bill through rate-setting authority. City should work to ensure community solar projects are eligible for incentives and CSI rebates. City should undertake GIS mapping for optimal solar sites to help ESP bidder; adjust incentive program to reward PV system performance.

Summary. The Board of Supervisors passed and the Mayor signed into law in June 2008, a new Solar Energy Incentive Program. The bill was the result of work from the SF Solar Task Force, chaired by Phil Ting, the Assessor-Recorder of the City and County of San Francisco, and co-chaired by David Hochschild, formerly a Commissioner at the SFPUC. Representatives from the labor, environment, solar industry, and business communities were included as members, and an expert panel with members from the CPUC, SFPUC, SFDOE, SFDBI and PG&E served as advisors.

The task force sought to establish a goal of 55 megawatts of installed photovoltaic capacity in the City by 2010, reflecting the goal of 50 megawatts of in-City solar created in 2000 in conjunction with the Proposition H Solar Revenue Bond Authority. At the same time Solar Proposition B was approved with a promise to achieve a goal of 10 megawatts of solar power. The assumed H Bond issuance under the CCA program for solar photovoltaics will be for the amount necessary to finance between 31 MW and 103 MW of projects. The lower amount is the minimum requirement solar, while the higher amount assumes that all renewable distributed generation (DG) is solar. These photovoltaic systems would be on private and public sector rooftops, and contribute toward the initial 360 MW rollout of diverse local renewable and demand side technologies that will be developed by the CCA Supplier starting in 2010.

The Task Force released its Summary of Recommendations report in December, 2007, which included having the City create its own solar incentive program to supplement the rebates already offered by the state under the California Solar Initiative. The incentives were recommended for a few stated reasons.

San Francisco, which at the time had the highest targets for solar for any city in the nation, also has—according to a 2007 report— the lowest per capita rate of installed solar in the Bay Area. The Task Force attributed this phenomenon in part to the higher cost of solar in San Francisco—$10 per watt, or $30,000 for a typical 3 kilowatt system, versus $9.32 per watt elsewhere.

Description of the Program. The Solar Energy Incentive Program has been adopted as Chapter 18 of the City and County of San Francisco Environment Code.[43] The program provides for $2 million to $5 million per year over a ten-year period for the rebate program, for a total investment of $20 million to $50 million. The funds are supposed to come from SFPUC Hetch Hetchy revenues that are currently allocated to renewable energy and efficiency, and not from taxes or general revenues of the City.

Eligible systems must be at least 1 kilowatt in size, and there is not upper size limit. Customers must own the solar system to receive the rebate. Rebates for residential customers range up to a dollar value maximum of $3000 to $6000, depending on certain classification criteria established under ordinance. Commercial customers can get up to $1500 per kilowatt, up to a maximum of $10,000. The Program Administrator is authorized to adjust limits and rebate amounts, but may only increase them with authorization from the Board of Supervisors.

Significance to CCA Program. The Draft CCA Implementation Plan provides that the CCA Program will offer residents and businesses H Bond financing for home and business installations of solar photovoltaic systems.[44] An additional validation for local investment in solar rebates was not stated, but is equally important. State rebates peaked five years ago at $4.50 per watt, which covered nearly half of the customer's out-of-pocket expense. Current rebates have fallen to only $1.55 per watt, a 65% reduction, and are scheduled to decrease further as each tiered rebate level becomes fully subscribed. There is concern that the state rebates may not be enough to stimulate future demand, so a City rebate may be timely.

The City rebate caps established by ordinance are likely to benefit primarily, if not exclusively, smaller photovoltaic systems. As a frame of reference, the rate maximum established by the ordinance of $1.50 per watt would support installation of a system size up to 6.67 kilowatts for commercial sites. The residential caps of $3000 to $6000 would support sizes up to a maximum range of 2 kilowatts to 4 kilowatts. [45] Both of these ranges are appropriate for residential and small businesses, but would be virtually insignificant for large commercial or industrial photovoltaic systems that might be sized anywhere from 20 kilowatts up to 1,000 kilowatts.

Technical Issues. There are significant questions regarding the interaction of the City rebates with other public support programs. For example, the California Solar Initiative

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[43] Ordinance 102-08, File No. 071679, Approved 6/18/2008.

[44] Draft CCA Implementation Plan, p. 14

[45] Customers could build larger systems, but they would then have to accept a lower incentive payment per installed watt.

law (SB1) specified that the CPUC could adjust rebate levels to account for other tax and subsidy support for solar energy. One risk is that the CPUC might decide to lower rebates for customers receiving local rebates.

Another concern is interaction with federal tax credits, which have been set at 30% of installed cost in recent years, and that was recently extended under federal legislation for a period of 8 years. Public funds used to support a solar energy system may be considered as public contributions to capital for private use, and as such void part of the tax credit. If this is the case, then 30% of the value of the rebate could be annulled through reduction in the tax credit.

Finally, there is compelling evidence that upfront rebates in California may have the perverse and unintended effect of increasing the installed cost of solar systems, with installers taking 60% or more of the rebate value from the customer. If this is combined with a loss in value of the federal tax credit, the customer may literally get no benefit from the incentive payment. On the other hand, if the customer has little to no federal tax liability, and the City exerts some oversight on photovoltaic system costs, then the incentive would be of value. One way the City could do this is to evaluate the contractors bid, and if it is too high notify the customer that they should seek a more competitive price.

Implementation Time Required. The CCA Draft Implementation Plan adopted last year by the City includes a total City goal of 50 megawatts of photovoltaics, so to an extent the rebate program can be made a modular component of the City's overall CCA offering within a minimal time-frame. The CCA Plan creates collaborative opportunities to increase solar installations and reduce the cost burden through a variety of methods, including bulk purchasing, rebates, tax credits, low cost bond financing, general sharing of costs by all ratepayers, and developing a diverse portfolio of solar systems that can benefit from economies of scale. Given that the rebate program is supported by SFPUC revenues, the CCA Program could better ensure that the $2-$5 million per year (a small amount compared to the H Bonds and CCA Revenues being invested) create maximum benefit to San Franciscans, be cost-effective and optimized in terms of warranties, maintenance, and integration of smart grid and efficiency measures as they are rolled out as part of the community's CCA energy supply.

There is essentially no time lapse required to offer the rebate to CCA customers. There are important effects of being embedded in a network of other supports for solar energy. The City, and the Program Director, should seriously examine program design options that can insure that customers get the maximum possible value from the rebates. Careful coordination with other programs is critically important in this regard; integration, not balkanization, (of technology deployment, revenue, and risk) is the key to cost-effective application of intermittent local renewable technologies.

Potential Impacts to CCA. It is clearly the intent of the Board of Supervisors that this program be developed in coordination with a CCA. The rebate is funded by the SFPUC and designed to further "stimulate the growth in the City's supply of renewable energy." Recognition of CCA is reflected in the Ordinance; findings of Chapter 18 further states:

> "F. The SFPUC is pursuing the establishment of Community Choice Aggregation ("CCA") within the City. Implementation of CCA will allow the SFPUC to partner with private enterprise, leverage the purchasing power of a wider customer base and access the capital markets on a broader scale in order to expand its renewable energy generation asset portfolio."

Coordination with a CCA's purchasing and planning powers could significantly increase the effectiveness of the City's Solar Energy Incentive Program.

ii. PUC PPA Program

The SFPUC is planning to build 62 megawatts of new photovoltaic systems between fiscal years from 2008 to 2013. This will add to the two megawatts in total projects that have been built up to early 2008. Two types of transactions will be used: Design-Build contracts, and Power Purchase Agreements (PPAs). Design-Build contracts are conventional purchases of photovoltaic systems where either the utility or the customer can own the facility. Under a power purchase agreement, a third party owns the photovoltaic system. That party may also design and build the facility, or they may subcontract for construction.

The solar power purchase agreement includes a somewhat complex deal, which the third-party owner arranges. Often power is sold at a price that meets or beats the current utility rate, and has a price escalation schedule according to expectation of future rate increases. This price is much lower than the full cost of solar power, so several creative techniques are used to lower the cost for the customer:

- Low cost financing is obtained from investors or financial institutions that are willing to make a return that is far less than the 8% to 15% rate that is normal for electric power infrastructure. Investors may accept as little as 6% return based on the idea that photovoltaics are low risk and are secured by a long-term purchase agreement.
- Federal tax credits reduce the first year costs by 30%, by using an owner that has a significant tax liability.
- State or local subsidies are obtained, currently $1.55 per watt from the California Solar Initiative in PG&E's service territory, but scheduled to decrease in the next years.
- Market power and building to scale are used to help reduce installed costs; usual customers for PPAs are businesses or public facilities with large flat roofs and high energy demand
- The vendor takes ownership of the environmental value in form of Solar Renewable Credits (SRECs), which are sold either on the market or directly to the customer as a surcharge added to the electricity purchase. Prices can range from 3

cents to as high as 15 cents per kilowatt hour, which subsidizes the project's remaining excess costs after all the benefits listed above have been incorporated.

Potential Impact to CCA. SFPUC plans to install eleven solar projects by third party-financing entities/integrators under seven power purchase agreements. All together these PPAs account for 59 megawatts out of the 62 megawatts of total SFPUC projects.

If built, the combined size will add 62 Megawatts to the 31 MW minimum to 103 MW within the 360 MW rollout requirement adopted in the CCA Implementation Plan. If the SFPUC contracts for these facilities in a manner that augments a sale to the CCA, the resulting local photovoltaic capacity may legally be sold into the CCA Customer Portfolio, providing critical capacity balancing opportunity, contributing to fulfillment of the 51% RPS schedule, and enhancing San Francisco's local energy independence. The main questions for a CCA are whether these projects will in fact all get built, the degree of coordination of planning and operation with the CCA, and whether power transactions such as resale and swaps can occur. Whether or not all the SFPUC facilities get built, the CCA plans to build its 31 MW[46] share of photovoltaics this is essential to its goal of relying on local clean energy.

Implementation Time Required. SFPUC is planning to build over 60 megawatts of solar power facilities in San Francisco by approximately 2012. Assuming the CCA Program is up and running by 2010, excess solar capacity could become available as SFPUC builds out its solar facilities. There is potential for SFPUC to sell excess power from any solar plants built by the utility or its customers to a CCA and vice-versa. Power swapping is another option that may help to assure more reliable performance of systems that rely upon renewable energy. Intermittent renewables, such as solar and wind power, produce only when a natural resource is available. Reliability can be improved by a variety of techniques, including:

- combining the output of facilities distributed over a wide geographic area to counter local variability of sun and wind
- combining the output of different types of renewables that might be complementary, such as solar that produces during the day and wind the increases in the late afternoon and evening
- coordinating energy demand to complement the output of variable renewables
- using technologies such as batteries and pumped water power storage
- backing up intermittent renewable energy with other more controllable electric generation resources using hydropower, natural gas, hydrogen or biofuel.

Technical Issues. Some of the legal issues surrounding power agreements between SFPUC and the CCA are addressed in other sections of this report as it relates to allowable transactions under current PG&E tariffs as well as the Raker Act. In the City's

[46] This is rated as 25 MW (ac).

PG&E Interconnect Agreement renewal last year, the SFPUC negotiated a swapping arrangement with PG&E. Recently, in LPI's interview of SFPUC Power Enterprise Assistant General Manager Barbara Hale, she expressed her agency's interest in selling SFPUC-owned solar photovoltaic capacity to the SF CCA. Swapping would also be an option once CCA capacity is installed. Under state law, the SFPUC is allowed to credit excess solar power produced at one customer site to customers located at another site that is remote from the first customer. Both of these must be customers of the SFPUC. This transaction is not allowed between customers of SFPUC. On the other hand, there is nothing to block direct power sales and swaps of this solar power, as discussed above. So long as there is no barrier to these more normal power sales and swaps, it is not clear if there would be any benefit for a CCA to change the state's "remote net metering" bill to allow such behind the meter transactions across the CCA/SFPUC boundary.

Recommendations. It is clear that there could be real benefits from coordinating the resources of SFPUC and the CCA. *LPI recommends that the CCA Program enter into an agreement with SFPUC for the sale of excess solar capacity and energy to the CCA. LPI recommends that the agreement include provisions for planning and operation of renewable generators and other resources that can help firm up the local solar resource, and that transactions between the two entities be coordinated to significantly improve the reliability of renewable power supplies.*

SFPUC Solar Implementation Plan

	SFPUC Municipal SOLAR IMPLEMENTATION PLAN (MW)	FY 2008-2009	FY 2009-2010	FY 2010-2011	FY 2011-2012	FY 2012-2013	TOTAL(MW)
	PROJECT NAME						
ALL1	Sunset Reservoir and Pier 96 (PPA 1)	5.0					**5.0**
ALL2	CREBS Projects- Chinatown HC, Muni Woods and Ways and Means (Design Build)	0.3					**0.3**
ALL3	SF Main Library (Design Build)	0.2					**0.2**
ALL4	SF City Hall (Design Build)	0.2					**0.2**
ALL5	Stanford Heights (PPA 2)		1.0				**1.0**
ALL6	SF General Hospital Parking Garage (Design Build)		0.5				**0.5**
ALL7	Bus Washing Facility 15th and Harrison (PPA 3 includes Roof Replacement)		1.0				**1.0**
ALL8	Civic Center Solar 2 (Design Build)		0.1				**0.1**
ALL9	525 Golden Gate (Design Build)			0.2			**0.2**
ALL9	University Mound North Basin (PPA 3)			2.0			**2.0**
ALL10	Pulgus Reservoir (PPA 3)			2.6			**2.6**
ALL11	Civic Center Solar 3 (Design Build)			0.2			**0.2**
ALL12	City Reservoir (PPA 4)				2.0		**2.0**
ALL13	Tesla Ground Mounted (PPA 4)				5.0		**5.0**
ALL14	SFO Terminal 3 (Design Build)				0.3		**0.3**
ALL15	Sunol (PPA 5)					25.0	**25.0**
ALL16	Hunters Point (PPA 5)					10.0	**10.0**
ALL16	SFO- Multiple Locations (PPA 6)					5.0	**5.0**
ALL17	Transbay Terminal (PPA 7)					1.0	**1.0**
ALL18	Multiple School Locations (Design Build)					1.0	**1.0**
	TOTAL Solar MWs Coming on line	**5.65**	**2.6**	**5**	**7.3**	**42**	**62.55**

10/1/2008

iv. Solar Photovoltaics Zoning and Permitting

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Background

In February 2007, Mayor Gavin Newsom established the San Francisco Solar Task Force to increase the use of solar energy in San Francisco by finding innovative solutions to achieving CCSF goal of 10,000 rooftops with solar panels by 2010. In January 2008, the Mayor and the Building Official published a set of permit procedures that substantially improved the permit process to be in keeping with the 2004 New Solar Rights Act, which limits building official's review of solar installations only to those items that relate to specific health and safety requirements of local, state and federal law. The current process is much more user friendly, cost effective, and timely.

Permitting

Department of Building Inspection
Over 90% of solar photovoltaic applications in San Francisco are permitted over-the-counter with an electrical permit at a cost of $170 (as of September 2, 2008 when permit rates were increased). For systems under 4kW, which makes up the majority of applications, an Electrical Permit application is the only requirement. For systems over 4kW, a simple electrical diagram must accompany the electrical permit application for over-the-counter review.

As long as the solar photovoltaic panels are installed following the manufacturer's requirements, no structural review is required; if not, than over-the-counter review is required at the time of the electrical permit. After the panels are installed and prior to grid connection, the Department of Building Inspection requires an electrical inspection. Inspections are typically scheduled within 48-hours of the request; applicants are given a time frame of either morning of afternoon.

Department of Planning
Because of the California state law that exempts solar photovoltaics from planning review, no planning review is required for the majority of solar permitting projects. The one kind of installation that triggers planning review is the addition of a panel mounting structure other than the manufacturer's standard mounting rack. While not common, there are instances in San Francisco where an applicant has proposed a trellis-like mounting system for the solar photovoltaics, which then triggered planning review.

Additional structures trigger the need for a building permit, which is then conditioned by various City departments as it is routed. The cost for the building permit is based on the assessed valuation of the project.

It is also important to note that in the case of all renewable technologies, building permits open the door for the discretionary review process. Discretionary Review is a process unique to San Francisco and allows any member of the public to request a Planning Commission review of the subject project, thus taking away the decision making power from staff. 30-day noticing is required for any building permit in a Residential and/or Neighborhood Commercial zoning district, as well as in historic overlay districts. Planning Commission actions are final unless appealed to the Board of Supervisors within 30 day of Commission action.

If the additional mounting structure is proposed on a historic building, there is an additional set of procedures that must be followed.

<u>Additional Structures to Historic Buildings</u>

Additional structures to historic buildings that are proposed as part of the photovoltaic systems require a *Certificate of Appropriateness* (C of A) from the Landmarks Preservation Advisory Board (LPAB)/Planning Director or a *Permit to Alter* from the Planning Commission, depending on the geographic location of the building.

- A *Certificate of Appropriateness* is required for Historic Landmark buildings and structures located within a designated historic district, per Article 10 of the Planning Code. *Estimated permit time: ~1 ½ to 3 months.*

    Certificate of Appropriateness permit process:
    - Landmarks Preservation Advisory Board makes a recommendation to the Planning Director, who can either accept or deny the recommended action.
    - The issuance of a C of A by the Department is not appeal-able; however, if someone disagrees with the C of A determination, he or she can appeal the subsequent issuance of the building permit to the Board of Appeals.
    - C of A's that are disapproved by the Landmarks Board are referred to the Planning Commission for review and approval or disapproval.
    - Cost: The cost associated with a *Certificate of Appropriateness* is expensive and at this time, there is no relief for renewable energy technologies:

Construction Cost	Fee Schedule
$0 to $999	$558 (=$545 + Board of Appeals surcharge $13)
$1,000 to $19,999	$1,103 (=$1,090 + Board of Appeals surcharge $13)
$20,000 or more	$5,058 (=$5,045 + Board of Appeals surcharge $13)

- *Permit to Alter* is required requirements is required for applicable buildings located within the C3 downtown core district, per Article 11 of the Planning Code. *Estimated permit time: ~2-5 months.*

  Permit to Alter permit process:
  - Staff evaluates project and determines if it is Minor or Major
  - If determined to be minor, the alterations are approved administratively by the Planning Department by issuance of a letter signed by the Zoning Administrator titled "Notice of Determination of Minor Alteration." This results in an administrative approval of a Building Permit by the Planning Department as required by the Building Code However, if staff determines the alteration to be major, it requires Planning Commission approval.

Recommendation

Local Power recommends that the City consider a streamlined permit process for community solar facilities in excess of 4kw in rated capacity.

c. Urban Wind Turbine Development Issues

The most critical issue for wind power is available resource. San Francisco, according to measuring stations placed by SFPUC, has limited potential for wind generation. However, these measuring instruments were relatively close to the ground, and wind is known to increase significantly with altitude. Modern plants place the turbines on high towers that can be well over 100 feet above the ground. If the height is sufficient, the resource can increase by a full wind class and convert marginal areas into viable opportunities. The most useful action the City could take would be to find ways to allow wind towers of sufficient height that they will allow for economically useful development of wind in the City. These might best be located in commercial or industrial areas where noise and visibility are of reduced significance.

Zoning and Permitting for Wind Generation Systems

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- Wind resource in City sensitive to location.
- Height is biggest need to access wind; 250 feet or more ideal.
- Scale is critical; small wind turbines rarely cost-effective except in remote locations. There are only four microturbines in San Francisco.
- CCA might be able to reduce cost thru bulk purchase and low cost financing.
- Permitting and regulations a barrier to cost effective wind
- **Recommendation:** City should streamline permitting for small wind, relevant departments to draft new design guidelines, resolution outlining process. San Francisco Urban Wind Task Force should be brought into CCA planning process and expand duties to find locations where larger scale, and higher towers for wind generators would be acceptable. Pole mounted systems should be allowed. Zoning ordinance should be prepared for BOS approval. Demonstration Projects should be implemented.

Background

There are two types of micro-wind turbines, horizontal and vertical axis. Horizontal axis turbines are the standard turbines that consist of several (usually 3) blades and are typically pole mounted as a freestanding structure. Vertical axis turbines are cylinder eggbeater-like apparatuses that are typically mounted on top of buildings; they resemble metal chimneys when in operation. Of the two, vertical axis turbines are far easier to permit through the Planning Department and do not have the same wildlife safety issues since they appear to be a solid structure when in operation, making them visible to birds.

To date, there are 4 micro-wind turbines located in San Francisco, 3 of which are located in residential districts, and 1 at a museum. In summer 2008, Mayor Gavin Newsom established the San Francisco Urban Wind Task Force to increase the use of micro-wind by implementing a streamlined process and reduced fees. The task force is focusing on 5-topics:

- Wind data
- Permitting
- Cost and incentives
- Public awareness and demonstrations
- Social issues: Environmental (birds) and Job creation

On July 17, 2008, the Mayor issued an Executive Directive, directing the city's building inspection and planning departments to expedite permitting and minimize costs for wind power in the city. The Planning Department will be developing Design Guidelines for wind turbines in the next fiscal year. Until then, each turbine is reviewed by the Planning Department on a case-by-case basis.

Permitting

The permitting process for wind turbine structures is much more complicated than for solar because unlike solar, the California State Legislature has not exempted wind turbines from planning review. Wind generation systems require a Building Permit and an Electrical Permit at a cost that is based on the valuation of the project. The Building Permit is routed to various City departments including Planning, Public Health, Police and Fire. The Planning Department regulates the location, height, environmental impact and aesthetics. The Department of Public Health regulates fixed noise sources.

The primary permitting issues associated with wind turbines are manufacturer's strength and durability "listing", height, wildlife (bird) safety, and aesthetics. For a standard wind turbine application that does not trigger any historic preservation thresholds, and meets the height restrictions of its district, there is a two-tiered noticing standard, based on the kind of turbine:

- Roof mounted: No noticing required
- Freestanding: 15-day noticing period required

Product Testing and Listing

Please refer to Section 1: Emerging Technology – Technical Assessment of Emerging Technologies.

Height exceptions and restrictions

Each individual zoning district/designation has its own height restrictions; however, height exceptions for wind generation equipment are allowed in all zoning districts. Up until last year, this was true with the exception of the Bernal Heights Special Use District.

As it currently reads, the height exception for wind generation systems is only for roof-mounted systems, not for freestanding systems. This is stipulated by the Planning Code, which specifies that in order to be eligible for the 10' or 16' height exception, the use may not exceed 20% of the roof area. The Zoning Administrator is currently reviewing this and will make a ruling as to whether or not freestanding structures are also covered by the exception.

Bernal height exception district

Planning Code Section 260(b)(1)(A) – allows, in Height Districts of 65 feet or less, wind generation equipment to exceed the height limit by a maximum of ten feet; and, in Height Districts of greater than 65 feet, wind generation equipment to exceed the height limit by a maximum of 16 feet. This means that in a residential district with a height restriction of 30-feet, a wind collection device could be constructed at a height of 40-feet.

Bernal Heights Special Use District: Planning Code Section 242(e)(1)(D) overlays the height exemption prescribed by Section 260(b)(1)(A) with a further restriction in the Bernal heights Special Use District limiting such equipment to a maximum height of 42" above the permitted heights. This means that wind generation equipment, commonly known as wind turbines, would not be able to be located high enough off the ground to have any meaningful effect. Resolution No. 17496, adopted in October 2007, amended sections of the Planning Code to allow wind turbines to exceed the height limits of the Bernal Heights Special Use District by up to ten feet, provided that they are vertical axis, limited in diameter to 3 feet.

The amendment allows the installation of small wind-powered electrical generation equipment in the Bernal Heights Special Use District at heights that are permitted elsewhere in the City, and at heights that are presently allowed in the SUD for antennas and chimneys.

Citywide height exception permit process

Planning Code Section 253 – Review of proposed buildings and structures exceeding a height of 40 feet in R districts, specifies that for any structure over 40-feet in an R district, Planning Commission *Conditional Use* approval is required.

Conditional Use permit process:

1. Apply for building permit from the Department of Building Inspection.
2. Application is routed to Planning Department for review.
3. Planning Department will require a Conditional Use approval prior to signing off on building permit.
4. Applicant meets with Planning Department staff. At that time, fees will be determined on the basis of estimated construction costs. Fees are set forth in Planning Code Article 3.5A. Should the cost for staff time necessary to process the application exceed the initial fee paid, an additional fee for Time and Materials may be billed upon completion of the hearing process or permit approval.

Construction Cost	Fee Schedule/Formula
$1 - $9,999	$1,206 + $111 (BOS appeal surcharge) = $1,317
$10,000 - $999,999	Cost: _____ - $10,000 x 0.557% = _____ + $1,206 + 111 = ***FEE***
$1,000,000 - $4,999,999	Cost: _____ - $1,000,000 x 0.664% = _____ + $6,722 + 111 = ***FEE***

*Time and materials (Planning Code Section 352(c)(2)):
**Where an applicant requests two or more approvals involving a Conditional Use, Certificate of Appropriateness, Permit to Alter a Significant or Contributing building both within and outside of Conservation Districts, the amount of the second and each subsequent initial fees of lesser value shall be reduced to 50% plus time and materials.

5. Required application materials:
   - 300-foot Radius Map
   - Address List: Two typewritten lists, one on gum-backed, self-adhering labels that meet the specific CCSF Planning Dept. requirements.
   - Plans:
     - Plot plans: Show the subject lot and adjacent lots, and existing and proposed structures, on both the subject property and on immediately adjoining properties, open spaces, driveways, parking areas, trees, and land contours where relevant.
     - Elevations: Required when there is proposed new construction.
   - Photographs: Not to exceed 8 ½" x 14" in size
   - Required fees (see above)
   - California Environmental Quality Act and Chapter 31 of the San Francisco Administrative Code may require an Environmental Evaluation (separate fee required).
6. Noticing:
   - Falls under the 2006 Posting and Mailing Ordinance.
   - 20-days prior to hearing, Applicant Responsibility
   - Newspaper ad

- 30” x 30” posting at site (posted following the rules prescribed by Planning Department handout
- 300” radius mailing to neighboring property owners

7. Public Hearing & Action
8. Appeals: Planning Commission actions are final unless appealed to the Board of Supervisors within 30 day of Commission action.

Noise

Article 29 of the Police Code regulates noise; however, fixed source noise, such as wind generation, is under the purview and jurisdiction of the Director of the Department of Public Health. The maximum noise level is prescribed differently for each individual district (see matrix below). All proposed turbines must meet the noise criteria set by the Police Code. Under Article 29, there are two policies that apply to fixed source noise:

<u>Article 29, Section 2901.11 – Unnecessary, Excessive, or Offensive Noise:</u>
“Unnecessary, excessive, or offensive noise shall mean any sound or noise conflicting with the criteria, standards, or levels set forth in this Article for permissible noises. In the absence of specific maximum noise levels, a noise level which exceeds the ambient noise level by 5 DBA or more, when measured at the nearest property line or, in the case of multiple-family residential buildings, when measured anywhere in one dwelling unit with respect to a noise emanating from another dwelling unit or from common space in the same building, shall be deemed a prima facie violation of this Article.”

<u>Article 29, Section 2909 – Fixed Source Noise Level:</u>

Zoning District	**Time Period**	**Sound Level (dBA)**
R-1-D, R-1	10 P.M. – 7 A.M.	50
R-2	7 A.M. – 10 P.M.	55
R-3, R-3.5, R-4	10 P.M. – 7 A.M.	55
R-5, R-3-C. R-3.5-C	7 A.M. – 10 P.M.	60
R-4-C, R-5-C	*Unspecified*	*Unspecified*
C-1, C-2, C-3-O	10 P.M. – 7 A.M.	60
C-3-R, C-3-G	7 A.M. – 10 P.M.	70
M-1	Anytime	70
M-2	Anytime	75

Rezoning Ordinance. LAFCO, in consultation with the SFPUC and Department of Planning, should identify areas within the City where wind generation devices would be appropriate at heights that would maximize energy production. This would vary from area to area, depending on wind patterns and the natural environment; in appropriate locations, this should include heights that are typically reserved for sky scrapers and bridges.

Once these locations are identified, the Board of Supervisors should adopt an overlay zoning district specifically for over-sized wind generation devices, including specific design guidelines and development regulations. In doing so, large-scale (tall) wind resources would be allowed as a permitted use in specific areas predetermined by CCSF, thus enabling economically feasible development of wind energy production and minimizing bureaucratic process delays and associated CCA portfolio costs.

Recommendation: Recommend the Board of Supervisors adopt a resolution directing staff to:

- Identify potential areas that could accommodate large-scale (tall) wind generation devices via an overlay zoning district;
- Draft an overlay zoning district with specific design guidelines and development regulations for over-sized wind generation devices; and
- Adopt an overlay zoning district in appropriate land use areas that permits wind energy production at maximum heights and prescribes a set of development regulations/design guidelines.

Permit Streamlining. With the current case-by-case review, there is a great deal of process and cost associated with permitting an individual urban wind generation device in San Francisco. In order to facilitate a large-scale rollout of micro-wind, this must be addressed without jeopardizing the Department of Building Inspection's mandate to protect the health, safety and welfare of the public. To do so, LPI recommends the following approach:

1. Outline technical criteria for acceptable urban wind generation devices.
2. Develop Design Guidelines for urban wind generation devices.
3. Adopt a list of approved small wind turbines that meet technical requirements and are consistent with Design Guidelines; specify if certain devices are only appropriate for certain geographical areas or zoning designations.
4. Adopt a process to add urban wind generation devices to the approved list.

In the proposed model, the Department of Building Inspection will already have the specifications and structural drawings on file for devices that are on the approved list, as is the case for solar photovoltaics. So long as the device is listed and it's location is consistent with the design guidelines (to be verified over-the-counter), applicants should only need an electrical permit.

Recommendation: Adopt a resolution outlining the proposed process, directing the Department of Building Inspection to draft technical requirements, directing the Department of Planning to draft Design Guidelines and directing the two departments to work collaboratively to develop a list of approved turbines. The two departments also need to create a process to add devices onto the list in the future.

Demonstration Projects

The Department of Building Inspection currently allows demonstration projects on a case-by-case basis. Currently, a 'demonstration project' seems to be an undefined catchall. The Department of Building Inspection needs to set standards for demonstration projects and establish criteria to determine if a demonstration project has performed well enough in its demonstration phase to be included as an allowed device.

LPI recommends that wind generation devices that do not qualify for the approved list (IE demonstration projects) should continue to require a building permit, which automatically triggers Planning Department review. These projects should continue to be reviewed on a case-by-case basis.

Recommendation: Adopt a resolution directing the Department of Building Inspection to develop standards for demonstration projects, including performance criteria.

Height Exceptions

Currently, the height exception for wind generation devices specifies that it is for roof-mounted systems. By default, this excludes free mounted devices.

Recommendation: Adopt a resolution for a zoning text amendment that expands the height exception for roof mounted wind generation devices to include pole mounted wind generation devices.

Permit Fees:

See Permit Fees recommendation section in the section of this Report titled "Overall Permitting Recommendation," in Section 2(a).

d. Development Opportunities for Cogeneration

SFDOE study showed potential for 106 MW new cogeneration; site manager concerns about owning cogeneration.

NRG proposed downtown steam loop 50 MW cogen plant.

Cogen provides critical base-load (24/7) reliable power.

Utility companies identified by CEC as barrier to cogeneration.

Overcome barriers through CCA ownership and operation. Excess power can be purchased by CCA.

Cogeneration lowers carbon footprint with efficient fuel use.

CCA can use alternatives such as biogas, hydrogen, and fuel cells.

Recommendation: City should immediately pursue cogeneration opportunities with NRG and others for CCA power agreements. SFDOE should initiate boiler retrofit program focusing on conversion to cogeneration.

Introduction. In addition to developing renewable resources, the CCA must also procure low-cost, clean energy resources to provide the non-renewable complement of the City's CCA portfolio. To the extent CCA can find local clean electricity supplies that are reliable and affordable, it will reduce CCA Program dependence on increasingly volatile and environmentally damaging wholesale grid power. A particularly valuable resource that can meet these requirements is cogeneration, also called combined heat and power (CHP). A dramatic opportunity exists to implement an efficiency measure on existing natural gas boilers in downtown San Francisco through means of heat capture and conversion to electricity. A substantial amount of heat waste is currently unharnessed in San Francisco. The public is often confused by this technology because it is nonrenewable – it is replacing your water heater with a water heater that makes electricity out of the extra heat the boilers otherwise simply release into the air. To the extent that the bpoilers are natural gas-fired, the harvested power is not "renewable." So while gas-fired CHP could not qualify as renewable as part of the city's 360 MW rollout requirement, it would capture massive waste heat that is now taking place in downtown San Francisco, and provide very inexpensive, secure local power resources for all San Franciscans. In effect, cogeneration would lower, not increase, the CCA net cost of power, by implementing an efficiency measure on existing natural gas boilers. Therefore it is a highly advisable resource development strategy for the CCA Program.

Cogeneration systems typically run on natural gas, but actually reduce natural gas consumption relative to a steam boiler or combustion turbine by greatly improving the utilization of the thermal energy in the fuel. This is accomplished by generating electricity and converting the hot exhaust gas from the combustion process to steam for productive use. Cogeneration opportunities exist where natural gas is already used to produce steam.

While not renewable, CHP is among the most cost-effective clean energy resources available for development in San Francisco. The CHP payback period is typically 6-7 years when no incentives are used.[47] Using waste heat to power downtown San Francisco is therefore recommended for inclusion in a CCA Program Basis Report.

A nascent natural gas efficiency program at the SFPUC is being developed to improve the efficiency of existing boilers throughout the City. Expanding this program to include conversion of these steam plants to CHP would be a natural fit for the CCA program.

Cogeneration represents a sizable local resource. 60 megawatts of CHP capacity is already in operation in the City (including the airport CHP plant). The potential for at least 106 additional megawatts has been identified in a City-sponsored CHP study.[48] Many locations around the City are suitable for CHP, though current barriers to development of CHP can be significant. A CCA can overcome these barriers by providing financing, expertise, guidance through permitting, protection against perceived risk, and contracts to buy surplus power.

There are several advantages to CHP relative to utility-scale power plants. These systems can be built at a small scale in or on existing buildings, so that no new land needs to be set aside for a stand-alone power plant. California Environmental Quality Act (CEQA) approval is generally limited to compliance with local air quality regulations when the CHP plant is located in or on an existing building. In contrast, CEQA approval for a stand-alone power plant is generally lengthy and often controversial. CHP is also one of the few locally available energy resources that can provide 24/7 baseload power. It can also reduce carbon emissions, negating the potential need to rely on nuclear power, while serving as a reliability anchor to the CCA's 51 percent renewable energy portfolio.

The mix of power generation sources serving California include natural gas (42 percent), large hydro (19 percent), coal (16 percent), nuclear (13 percent), and renewable resources (11 percent). Nearly all of this power is generated at large sites, and transmitted through an extensive transmission grid.[49]

Power production in the City of San Francisco differs somewhat from that of the state level. All municipal buildings are powered by large hydro from the Hetch-Hetchy power plant. PG&E provides the rest of the City with a power mix that consists of natural gas (44 percent), nuclear (23 percent), large hydro (17 percent), coal (2 percent), and renewable resources (13 percent).[50]

Typical natural gas-fired electric generators convert anywhere from 35 percent (boilers and peaking gas turbines) to 55 percent (state-of-the-art baseload combined cycle plants) of the fuel's thermal energy into electricity. Forty-five (45) to 65 percent of the heating value of the natural gas fuel goes unused at the power plant and is released into the

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[47] K. Davidson – DE Solutions, *Combined Heat and Power*, PowerPoint presentation, Carlsbad Chamber of Commerce Sustainability Committee Forum, October 3, 2008.
[48] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007
[49] Ibid, p. 1.
[50] Ibid, p. 1.

environment as waste heat. Many of California's older power plants use many millions of gallons of seawater a day to remove this heat. Wet cooling towers and air-cooled condensers are also used for this purpose.

Cogeneration in the form of CHP uses an internal combustion engine, gas turbine, or fuel cell to produce electric power and puts the hot exhaust gas to productive use. Nearly all of the CHP systems in operation in San Francisco either use internal combustion engines or gas turbines.[51] The heat in the exhaust gas of these combustion units is used to heat the air in an office building, provide hot water or steam, drive a dehumidifier, or drive an absorption chiller to provide refrigeration and cooling. With this large range of uses for the exhaust, any building with a significant heating and/or cooling load is a candidate for CHP. CHP systems can achieve overall thermal efficiencies in the range of 80 to 90 percent.

The carbon footprint of boiler plants and simple-cycle peaking turbine plants is in the range of 1,100 to 1,200 lb CO_2 per megawatt-hour (MWh).[52] The carbon footprint for a baseload combined cycle plant is approximately 820 lb CO_2 per MWh.[53] However, California combined cycle plants have a relatively low capacity factor on average, in the range of 50 to 60 percent, indicative of a "load following" operating pattern that is less fuel efficient than baseload operation.[54] Operating at partial load significantly reduces the efficiency of the combined cycle plant. Efficiency drops about 10 percent relative to baseload operation when the combined cycle plant is operating at 50 percent load.[55] As a result, a combined cycle unit operating much of the time at part load could be expected to have an average CO_2 emission factor in the range of 900 lb CO_2 per MWh, or about 10 percent higher than the baseload CO_2 emission rate.

In contrast, the carbon footprint of a properly designed baseload CHP plant is approximately 640 lb CO_2 per MWh.[56] Properly designed in this context means the CHP plant is sized for the minimum thermal load at the site to ensure the plant is always operating at maximum efficiency. Figure 1 provides a compares the carbon footprint of several CHP options to a baseload natural gas-fired combined cycle power plant.

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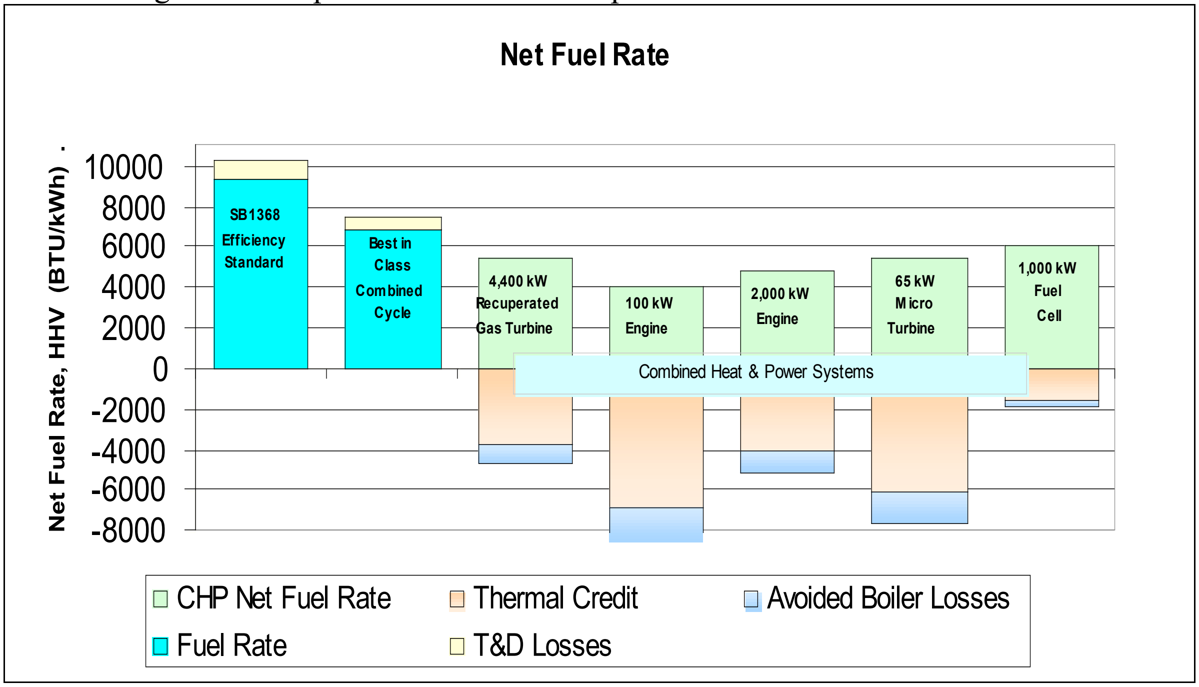
[51] Ibid, p. 10.
[52] Natural gas CO_2 emission factor is 117 lb CO_2 per million Btu. Heat rate of simple cycle combustion turbine is approximately 10,000 Btu/kWh, or 10 million Btu/ MWh. This equates to a CO_2 emission rate of 1,170 lb CO_2 per MWh.
[53] Assumed heat rate of a combined cycle power plant is 7,000 Btu/kWh at baseload (full power) operating conditions. Multiplying by the natural gas CO2 emission factor gives a CO_2 emission factor for combined cycle of approximately 820 lb CO_2 per MWh.
[54] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, December 2007, p. 61.
[55] R. Kehlhofer, et al, *Combined Cycle Gas & Steam Turbine Power Plants - 2nd Edition*, Figure 8-3, part load efficiency of GT and CC, p. 211. For example, a combined cycle unit with a baseload "high heating value" heat rate of 7,000 Btu/kWh would have a heat of 7,700 Btu/kWh, a 10 percent increase in fuel consumption on a unit basis, at 50 percent load.
[56] San DiegoGas & Electric, *2007-2016 Long Term Procurement Plan*, Vol. I, Dec. 11, 2007, p. 207.

Figure 1. Comparison of Carbon Footprint of Various CHP Alternatives[57]



CHP systems improve efficiency by significantly reducing the total natural gas consumption that would otherwise be necessary to produce heat or electric power in two separate systems. Cogeneration complements the City's goal of obtaining half of its electric power from renewable energy sources by increasing natural gas usage efficiency in the other half of the CCA's electricity supply.

Proposed SFPUC CHP Retrofit/Upgrade Program

The SFPUC has a new program to identify and retrofit natural gas boilers in the City. This program offers the opportunity to identify locations where highly efficient CHP plants can supply baseload power to balance out intermittent renewable energy sources.

The San Francisco Department of the Environment has prepared a strategic plan describing the objectives of the City's energy efficiency partnership with PG&E, entitled SF Energy Watch Program Implementation Plan. The Plan refers to a new program for natural gas efficiency to be implemented by the SFPUC. The program involves upgrading the efficiency of natural gas powered boilers for dozens of municipal facilities. Candidates for upgrade are to be identified and ranked for priority, with new projects designed by SFPUC staff and their contractors. This program has great potential significance for a citywide CCA, as it provides an off-the-shelf vehicle for expanded development of CHP plants within the City.

[57] K. Davidson – DE Solutions, *Combined Heat and Power*, PowerPoint presentation, Carlsbad Chamber of Commerce Sustainability Committee Forum, October 3, 2008.

Obstacles to Increasing CHP Use in San Francisco

Investor owned utilities (IOU) prefer for financial reasons to sell power to customers: 1) from the utilities' own generation assets or 2) sell power from more distant third party providers that is transmitted over utility-owned transmission lines. Buying power from its customers runs counter to core IOU financial interest – the construction of new IOU-owned generation and transmission infrastructure. Construction of new infrastructure is the primary mechanism available to the IOU to increase its revenue stream. The cost of this infrastructure, including a guaranteed rate of return to the IOU in the range of 11 to 12 percent, is borne by ratepayers.[58] The removal of significant amounts of load from the grid by IOU customers installing CHP will over time undercut the need for new sources of IOU revenue, specifically new generation and transmission.

The March 2007 *Distributed Generation and Cogeneration Policy Roadmap for California* report prepared by CEC staff calls for ten more years of subsidies for distributed generation technologies. The CEC indicates that significant energy policy changes will be necessary to accelerate the development of CHP in California (in an IOU-dominated structure). These include incentive payments for CHP under the CEC's Self Generation Incentive Program.[59] Making such policy changes, according to the report, could turn distributed generation from a small contributor that currently provides 2.5 percent of peak power to a significant provider that meets 25 percent of the state's peak power needs by 2020.[60]

Among the changes envisioned by the CEC to generate a quarter of the state's power from off-grid distributed generation are transparent dynamic rates for electricity. The report also recommends removing institutional barriers. For instance, distributed generation has been hampered by a lack of uniform rules and standards that could speed installation of equipment.

Interconnecting CHP with the utility distribution system has been an obstacle for some CHP developers. The experience of CHP developer Tecogen is instructive. A 60 kW Tecogen CHP plant has been in successful operation at 1080 Chestnut Street, a residential high-rise on Russian Hill, since 1988. According to an independent energy auditor, the system resulted in $400,000 in energy savings in the 1991-2000 period when natural gas prices were very low relative to current prices.[61] Yet this is the only Tecogen system in San Francisco. The following quote summarizes the difficulties Tecogen has encountered attempting to develop CHP projects in California:[62]

> "Just a few years ago, Bob Panora was a sort of DE (distributed energy) poster child, embodying a whole segment of power-project developers shut out of markets, at least

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[58] June 2005 FERC approval of rate schedule for Trans Bay Cable.
[59] http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/
[60] Excerpt from California Energy Circuit, *State Sees DG Providing 25% Peak Power*, May 11, 2007, p. 8.
[61] Tecogen case study brochure, CM-60 and CM-75 Cogeneration Modules – 1080 Chestnut Street, San Francisco, www.tecogen.com.
[62] Distributed Energy Magazine, *Dream Machine - An inverter connection to the grid lets CHP stay on when the lights go out*, November-December 2007.

> in part due to contrived utility obstacles. In testimony presented to the California Energy Commission at that time, Panora, president and chief operating officer of Massachusetts-based Tecogen Inc., told commissioners of being made to run a gauntlet of technical hurdles time and again to get his company's 75-kW combined heat and power (CHP) engines grid-connected - only to be shot down in the end on one pretext or another.
>
> Partly as a result of Panora's accounts, things soon began improving for DE developers. Changes to California's Rule 21 on interconnections were implemented in 2006, forcing utilities to lower some barriers."

The quote is from an article on a revolutionary grid interconnection device now being incorporated into Tecogen cogeneration modules. The innovative Tecogen inverter-based controller was developed in part with California Energy Commission funding. It allows individual cogeneration modules to operate independent of the grid and each other while maintaining the ability to seamlessly reconnect with the grid at any time.[63] As noted in the article:

> "From a customer perspective, the result is indeed a "dream machine." It's an elegantly simple, inexpensive circuit of engines which a) can be positioned around a site for optimal CHP efficiency that will save money and b) will keep running robustly and automatically, powering critical services, regardless of what the grid does or doesn't deliver."

IOUs have a disincentive to support CHP, regardless of customer benefits, as it has the potential to undercut traditional sources of IOU revenue. This reality is unlikely to change in the near-term.

How CHP Fits into the SF CCA

The situation for CCAs is just the opposite. CCAs *are aggregations of customers* who are looking at the power business from the customer's point-of-view. For customers in the CCA, a cogeneration plant is a potential source of lower-cost power, hot water, and space heating and cooling. The CCA would benefit in a number of ways by maximizing cogeneration opportunities that the IOU has either overlooked or opposed.

The benefits of CHP include:

- Reduced need for procuring power from the grid due to increased customer self-generation
- Local source of power for other CCA customers in the City using the customer's surplus
- Reduced reliance on constrained transmission system

[63] Ibid.

- Reduced fossil fuel consumption
- Reduced carbon emissions
- Reliable round-the-clock baseload power to help counterbalance variable renewable power
- Price hedge against risk on ‘high renewable’ power supply if natural gas prices fall

CHP provides a CCA that is heavily dependent on renewable energy supplies a reliable continuous source of power to counterbalance the variable output of wind and solar energy systems. An increase in local CHP frees-up capacity on existing transmission lines and eliminates the transmission and distribution losses associated with power imports. It also removes load from the grid that would otherwise serve as IOU justification to add new local peaker plants or other generation/transmission hardware.

The increased use of CHP would allow the City to reduce carbon emissions with a 50 percent renewable energy portfolio, even compared to a PG&E power mix that is already 50 percent carbon-free (with a combination of nuclear, hydro and some renewable resources). Cogeneration also responds to the question about how the City would be able to access a limited pool of clean energy supplies.

2007 Study of CHP Potential in San Francisco

The SFDOE commissioned a June 2007 study of CHP potential in San Francisco that summarizes potential CHP opportunities.[64] Sixty (60) MW of CHP are currently being generated in the City (including the international airport). This capacity includes the airport CHP plant (30 MW, turbines), the UCSF CHP plant (13.5 MW, turbines), twenty internal combustion engine CHP plants (all under 2 MW), three microturbine CHP plants (240 kW or less), and one fuel cell plant (250 kW).

The study also identifies an incremental minimum CHP potential of 106 MW, divided into the facility categories shown in Table 1.

[64] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007.

Table 1. Additional CHP Potential in San Francisco

Facility Type	CHP Potential (MW)
Hotels	20
Hospitals	4
Data centers	significant (unquantified)
Airports	airport has large CHP plant
Office buildings	80
Universities	most have CHP already, though potential for expansion/addition
Schools	significant (unquantified)
Residential high rises	>2
Wastewater treatment plants	Both plants have CHP
Health/fitness centers	significant (unquantified)
Miscellaneous	significant (unquantified) This category includes USPS distribution centers, warehouses with large heating or cooling loads

The CHP potential identified in the 2007 study is for numerous small CHP plants in the 1 MW range or less. Small CHP plants will generally incorporate an internal combustion engine, microturbine, or fuel cell.

There is one 250 kW fuel cell currently in operation in San Francisco at a U.S. Post Office distribution center.[65] The fuel cell CHP market is more active in other California urban areas. For example, the Sheraton Hotel and Marina Hotel in San Diego has a long-term agreement with Alliance Power for 1.5 MW stationary fuel cell power plant that supplies 70 percent of the hotel's electric power demand. The waste heat from the units is used to heat swimming pools and for domestic water heating. The plant consists of two fuel cells, a 1 MW unit and a second 0.5 MW unit. The 1 MW unit went online in December 2005, the 0.5 MW unit in mid-2006.[66]

A San Diego biogas provider, Biofuels, Inc. of San Diego, has also teamed with Fuel Cell, Inc. (Danbury, CT) to offer a renewable fuel cell CHP plant that utilizes processed biogas as fuel.

Microturbines combined with absorption chillers are another example. United Technologies markets microturbine-absorption chiller packages under the trade name "PureComfort®." Systems are offered at 240 kW, 300 kW, and 360 kW. The hot exhaust gas is utilized in an absorption chiller/heater. The efficiency of this system can reach 90

[65] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007.
[66] B. Powers, San Diego Smart Energy 2020, October 2007, p.

percent. A PureComfort® system is in operation at the Ritz-Carlton Hotel in San Francisco.[67]

Downtown steam loop CHP. One opportunity unique to San Francisco is conversion/replacement of the steam boilers that serve the downtown steam loop with a CHP plant. The downtown steam loop serves approximately 180 buildings. The owner, NRG, has proposed to incorporate a 50 MW LM6000 gas turbine to generate electric power at the plant while continuing to supply steam to the steam loop. NRG has submitted this project to PG&E in response to PG&E's request for offers to provide additional generation. PG&E is expected to select projects by the end of 2008.[68] A description of the proposed downtown steam loop plant upgrade is provided as Attachment B.

CHP Fuel Options

CHP technologies can use a wide variety of fuels to generate heat and power. The three primary candidate fuels are natural gas, biogas, and hydrogen.[69] Each of these fuel options is discussed in the following paragraphs.

Natural gas. Natural gas (CH_4) is the primary fuel to be applied in the combined heat and power technologies to be discussed in the next section. The natural gas infrastructure is well established and provides gas effectively to most buildings in San Francisco. The combustion of natural gas is much cleaner than oil or coal, and is a locally abundant natural resource.

Biogas/landfill gas. Biogas is the gas produced by the anaerobic digestion of organic matter, typically created at waste management facilities, or from organic matter decomposition in landfills. In this report both forms of gas are referred to collectively as "biogas." It is primarily composed of methane and CO_2, with trace amounts of nitrogen and hydrogen sulfide. Biogas and landfill gas is produced and released into the atmosphere as a byproduct, so using this resource in a CHP system is an opportunity to take advantage of a fuel source that would otherwise be wasted. Emissions are comparable to that natural gas.

One major advantage of biogas is that it is considered a renewable fuel. The U.S. Department of Energy has a renewable energy production incentive of 1.5 cents/kWh (1993 dollars) for all cogeneration systems using clean, renewable sources of fuel, including biogas. As a result, displacement of natural gas by biogas in a CHP plant is one alternative for generating continuous baseload renewable power.

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[67] UTC webpage, PureComfort® Solution Applications. See: www.fuelcellmarkets.com/united_technologies_utc

[68] Telephone conversation between B. Powers, Powers Engineering, and S. Hoffmann, NRG West, September 18, 2008.

[69] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007, p. 5.

Biogas is sold and delivered commercially in California for use in fuel cell CHP plants. For example, biogas (from landfills) refined to near-pipeline quality standard is currently available in the San Diego area for approximately $10.50/million Btu (delivered).[70] This compares to a retail natural gas utility charge to residential customers of $12/million Btu for natural gas.[71] The biogas is delivered by special truck at 2,400 psi in a series of cylinders. A single delivery truck (also fueled by biogas) can supply sufficient biogas to operate a 1.2 kW fuel cell CHP plant for approximately 12 hours.

For a 1.2 MW plant, the transportation/storage system consists of three mobile trailers each with 12 hours of stored biogas. A plant of this size requires a 30-foot by 60-foot space for the biogas trailers. At any given moment, one trailer is providing biogas, a second is onsite and empty, and the third is in route with a full supply of biogas.[72] The empty trailer is then returned to the landfill for filling and the cycle repeats itself.

The most seamless alternative for the transport and storage of biogas would be direct injection into the PG&E natural gas pipeline distribution network that serves the City. PG&E has led California natural gas utilities in the area of direct injection of biogas into the natural gas pipeline network. Figure 2 shows an operational biogas clean-up system at a dairy. The utility currently focuses on dairies producing large amounts of biogas from dairy cow waste processing operations. Biogas must meet PG&E's gas quality Rule 21.C. There is also a Bioenergy Interagency Working Group to address issues related to injecting biogas resources into utility natural gas pipelines.[73]

[70] Telephone conversation between B. Powers, Powers Engineering and R. Lyons, Syska Hennessy Group, September 19, 2008.
[71] SDG&E invoice to William Powers, natural gas invoice for July 2008, energy charge of $1.23 per therm or $12.30/million Btu.
[72] Telephone conversation between B. Powers and F. Mazanec, BioFuels, Inc., Escondido, CA, October 13, 2008.
[73] K. Brennan – PG&E, California Emerging Clean Air Technology Forum Stationary Source Session - Energy Generation From Digesters, July 9, 2008.

Figure 2. Clean-up System for Dairy Biogas prior to Injection in PG&E Pipeline

Biogas that is conditioned to meet pipeline quality specifications can simply be injected into the pipeline system and the greenhouse gas reduction benefits credited to purchaser. This approach would eliminate a potentially significant number of biogas delivery trucks circulating in the City if biogas is selected as part of the fuel mix for CHP plants in the City. This approach would also eliminate the need for onsite storage of biogas.

There is also the potential to produce biogas from green waste generated in CCSF. For example, the city of Toronto (Canada) established a highly successful green bin program in 2002, achieving a 95 percent compliance rate almost immediately. The green waste is converted to methane in an anaerobic digester plant. Toronto is expanding the green bin program and plans to construct two 60,000 ton per year anaerobic digesters to convert the organic waste into methane.[74]

Special gas clean-up requirements for landfill gas that are not issues with dairy or wastewater treatment plant biogas include vinyl chloride and siloxane. California natural gas utilities are examining clean-up of landfill gas for injection into natural gas pipelines. However, it is likely to be five years or more before the utilities establish an approved gas clean-up protocol that would permit landfill gas to be injected into utility pipelines.[75]

Hydrogen. Hydrogen gas could provide an alternative to natural gas, although hydrogen infrastructure does not yet exist. Its combustion with pure oxygen results in only heat and water. No CO_2 emissions are produced. Hydrogen gas can be generated by reforming methane gas or through the hydrolysis of water. Use of wind power or other renewable

[74] Biomass Magazine, *Go Green Pronto, Toronto*, January 2009 issue. See: http://www.biomassmagazine.com/article.jsp?article_id=2308
[75] Telephone conversation between B. Powers and F. Mazanec, BioFuels, Inc., Escondido, CA, October 13, 2008.

energy sources to provide the energy for the hydrolysis of water has been one approach suggested to generate "renewable" hydrogen for fuel.

State CHP Incentive Programs

AB 1613. The "Waste Heat and Carbon Emissions Reduction Act," AB 1613, was signed into law by Governor Schwarzenegger on October 14, 2007.[76] This legislation requires the IOUs to establish simple feed-in tariffs for excess CHP power up to 20 MW at each site. Public (municipal) utilities are required to: 1) establish programs that allow end-use customers to utilize CHP and 2) to provide a market for the purchase of excess CHP power at a just and reasonable rate.

AB 1613 also establishes a pay-as-you-save pilot program for eligible, 501(c)(3) non-profit customers. The pilot program enables the customer to finance all of the upfront costs for the purchase and installation of a CHP system by repaying these costs over time through on-bill financing at the difference between what an eligible customer would have paid for electricity and the actual savings derived for a period of up to 10 years. The IOUs must make on-bill financing of CHP available up to a cumulative total of 100 MW of CHP. PG&E's estimated share of this 100 MW total is in the range of 45 MW.

SB 1012. This 2008 bill re-establishes the non-renewable CHP incentives in the Self Generation Incentive Program (SGIP) that expired on December 31, 2007 for internal combustion engines (ICE) and small gas turbines through 2012. The SGIP incentive program currently covers only fuel cells and distributed wind generation through 2012.[77] The maximum system size is 5 MW. The minimum size is 30 kW for wind turbines and fuel cells using renewable fuels.[78] SB 1012 was held over in the 2008 legislative session due to the state budget impasse. It is now a two-year bill and will be reintroduced in the 2009 legislative session.

The SGIP program provides an incentive payment for up to 3 MW of installed capacity. For projects with capacities greater than 1 MW, the first 1 MW receives 100 percent of the incentive rate, the next capacity increment above 1 MW up to 2 MW receives 50 percent of the incentive rate, the last capacity increment above 2 MW up to 3 MW receives 25 percent of the incentive rate. Systems must be sized according to customer's electricity demand. The one-time SGIP incentive payments are:

[76] California Legislative Counsel's Digest, text of AB 1613, November 15, 2007.
[77] PG&E SGIP webpage: http://www.pge.com/mybusiness/energysavingsrebates/selfgeneration/equipment/
[78] http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA23F&state=CA&CurrentPageID=1

Fuel cells (renewable fuel)	$ 4,500/kW
Fuel cells (non-renewable fuel)	$ 2,500/kW
Distributed wind generation	$ 1,500/kW
Gas turbines and ICEs (SB 1012 proposed):	$ 600/kW
Microturbines (SB 1012 proposed):	$ 800/kW

Cogeneration Zoning and Permitting

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Background

CHP systems have been used since the mid-1980's in San Francisco. To date, over 26 systems are installed in office buildings, schools and Universities, hotels, hospitals and wastewater treatment plans. A June 2007, SFDOE report by Dr. Philip M. Perea, *An Assessment of Cogeneration for the City of San Francisco,* outlined the technology, its effectiveness, its applicability to San Francisco and the permit process. The report has provided the basis for this analysis.

The SFDOE would like to use the report to take cogeneration to the next level; however, there have not been any funds available to do so. In the future, the SFDOE would like to use some of the energy efficiency funds that are distributed by Pacific Gas and Electric as part of their responsibility to consumers, to fund such studies and working groups. Currently, the largest barrier to cogeneration is the interconnection with the PG&E-run electrical network. The interconnection, discussed below, is the most costly and time intensive process of all the renewable technologies. However, there are several options available that do not require the lengthy PG&E grid interconnection. One of these options discussed in the Draft CCA Implementation Plan is *islanding,* and another is a device manufactured by Tecogen, which is previously mentioned in this report.

Permitting

CHP systems require a series of permits issued from a variety of jurisdictions.[79]. The permit process can be lengthy and very expensive. Necessary permits include:

- Building and Electrical Permits (SF Department of Building Inspection)
- Certificate of Appropriateness or Permit to Alter, when required per a site's historic designation (SF Planning Department)
- Authority to Construct, and, Permit to Operate (Bay Area Air Quality Management District)
- Electrical Interconnection (Pacific Gas & Electric)
- Natural Gas Permitting (Pacific Gas & Electric)

Department of Building Inspection & Department of Planning
All cogeneration systems require a Department of Building Inspection (DBI) Building Permit and Electrical Permit at a cost that is based on the valuation of the project. The Building Permit is routed to various City departments including the Fire Marshall. The Fire Marshall is concerned with fuel storage and distribution, along with emergency shut-offs. In some cases, a Certificate of Appropriateness or Permit to Alter may be required by the Planning Department if the project is located at a site with a historic designation. This process is outlined under the solar permitting process.

(Estimated DBI permit time: 1 month; Estimated Planning Permit time (if necessary): 1-5 months)

Bay Area Air Quality Management District
An Authority to Construct and Permit to Operate, issued by the Bay Area Air Quality Management District (BAAQMD), is necessary for certain types of CHP systems. Internal combustion engine and gas turbine CHP systems must be equipped with advanced pollution control equipment to meet BAAQMD air emission control requirements. Gas turbine and lean burn internal combustion engine CHP plants are equipped with selective catalytic reduction (SCR) catalytic control systems for nitrogen oxide (NO_x) control. These plants are generally greater than 1 MW in size. Oxidation catalyst for carbon monoxide (CO) and volatile organic compound (VOC) may also be required depending on the specific combustion system. CHP plants equipped with these controls are as clean as state-of-the-art combined cycle power plants.

Rich burn internal combustion engine CHP plants utilize three-way catalysts to achieve very low levels of NOx, CO, and VOC emissions. There is almost no oxygen in the exhaust gas of a rich burn internal combustion engine. That is the reason an inexpensive three-way catalyst can be used for emissions control. This is the same emission control system used on gasoline engine passenger vehicles to achieve low levels of exhaust emissions. Rich burn internal combustion engine CHP plants are generally less than 1 MW in size.

[79] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007.

Microturbines that meet statewide air emission requirements established by the California Air Resources Board for microturbines receive a simplified air permit issued by the local air pollution control agency. Generally all microturbines produced by established microturbine manufacturers meet the CARB microturbine air emission requirements.

Fuel cells are exempt from air permit requirements. The reason for this is that a fuel cell is a chemical process that emits only water vapor and CO_2 when processing natural gas or biogas. Fuel cells produce only water vapor when processing hydrogen.

If the new CHP is subject to BAAQMD permit requirements and is within 1,000 feet of a school, public notice must be given to the school and parents, who are given 30 days to raise any concerns regarding the granting of an air permit for the proposed plant.

BAAQMD Fees are described by Regulation Three, Schedule B in the BAAQMD rules and regulations database [13] and are summarized below (as of June 2007):

Fee Name	**Description**	**Minimum Fee**
Initial Fee	$37.66 per MM BTU/hour	$201
Risk Screening Fee	$286 + $37.66 per MM BTU/hour	$487
Permit to Operate	$18.83 per MM BTU/hour	$144
Nearby School	Fee to inform school and parents	~$2,000

As an example, a small cogeneration system (85kW) burns natural gas at a rate of about 1 MM BTU/hour, and a large system (1.2 MW) burns natural gas at about 17 MM BTU/hour.

(Estimated BAAQMD permit time: 5-8 months)

Pacific Gas and Electric (PG&E) Electrical Interconnection
Electrical interconnection between a cogeneration system and the local utility power grid is described thoroughly by California's Rule 21 for utility interconnection. While businesses have the right to connect their system, it may decrease the stability, and safety of the utilities local equipment and infrastructure and it may take time to solve these issues. Issues may arise with systems >1MW, but not by default. For buildings within a secondary network, such as the downtown electrical network, the number of cogeneration systems in proximity to the proposed site and the load on the local electrical substation may affect interconnection issues.

The interconnection process will follow these steps (taken verbatim from the PG&E distributed generation website), and the initial application fee will be $800.

1. Application Review: The application will normally be acknowledged and reviewed for completeness within 10 business days of PG&E's receipt of the application. The application must be complete before PG&E can move onto initial review.
2. Initial Review: The review shall be completed, absent any extraordinary circumstances, within 10 business days of PG&E's acceptance of the completed

application. This review will determine if the generation facility qualifies for a simplified interconnection or if a supplemental review is required.

3. Supplemental Review: The review, if required, should be completed within 20 business days of deeming the application complete. Payment of $600 by the applicant for the supplemental review must be submitted to us within 10 days of issuance of review. The review will determine if the generation facility can be interconnected or if a Detailed Interconnection Study is required first.
4. Detailed Interconnection Study: The applicant must enter into an agreement with Pacific Gas and Electric Company to perform additional studies, facility design/engineering, and cost estimates for required interconnection facilities. The study is at the applicant's expense.

Typical times reported by PG&E are:

Type of Interconnection	Timeline
Simplified Interconnection	3 to 6 months
Supplemental Review	3 to 7 months
Detailed Interconnection Study	4 to 10 months

The costs for a Detailed Interconnection Study can vary greatly, as well as the incurred costs to an applicant for redesign and materials in a project.

Pacific Gas and Electric (PG&E) Natural Gas Permitting

Depending on the size of the proposed system, an increase in natural gas pressure may be required at the installation site and permits will be necessary to route this gas from the local gas main to the cogeneration system. Even the extension of a building's internal gas line several feet will require a permit, though requiring less evaluation and time to permit.

Cogeneration Permitting Recommendation. LPI's recommendation is to bundle the projects that make up the 106 megawatts of identified cogeneration potential into one large portfolio of permit applications. The portfolio will represent a large enough volume of applications that it will demand an efficient permit process. Bundling may be difficult and may require special procedures by the City.

Given the complexities of large-scale permitting efforts, political will is of importance. The process will be much smoother with support from the Board of Supervisors and LAFCO, who can exercise their political power to insist that all agencies and entities involved cooperate to the full extent of the law. In addition, they can appropriate the necessary staff resources to establish and facilitate a Cogeneration Permit Working Group and manage the permit processing.

The Cogeneration Permit Working Group should be comprised of members from each agency/entity that has a permitting role, including PG&E.

Conclusion

The expansion of CHP in the City would be complementary to the goals of the CCA. The SFPUC project that will focus on improving the efficiency of City steam boiler plants offers an intervention point. Existing low efficiency natural gas combustion systems owned by the City can readily be upgraded or replaced with high efficiency CHP systems. This program also provides an opportunity to establish CHP as the standard for any new City building heating system application.

In conjunction with a CCA, LPI recommends:

- SFPUC staff should share information about such projects with the SFLAFCO and CCA planners
- SFPUC staff should develop a list of potential sites where CHP might be appropriate in conjunction with boiler upgrades
- The sites should be evaluated for potential size of generation that would match the heat load, on-site electricity needs for the facility, and potential for export of such power from the site
- Solutions for operational, legal, and contractual barriers to selling power to in-City CCA customers should be identified
- The single biggest constraint to Cogeneration (Combined Heat and Power) is the grid interconnection with PG&E. This is an extremely long process and needs to be addressed by the City, and the California Attorney General's office has expressed interest in the matter.

e. In-City Renewable Generation Projects for Grid Reliability

By 2010 San Francisco will have lost 420 megawatts of local fossil capacity: CCA can help restore local green resources

CCA Phase I (210 MW)
31 MW photovoltaics
107 MW efficiency/conservation
72 MW renewable D.G.

CCA potential identified in report
106 MW cogeneration, 4.5– 9 MW tidal, 150 mw Potrero green peakers
30 MW demand response

SF CCA Program Local Resources	MW	MW
CCA Resource Plan (Phase I)		
Energy Efficiency Savings	107	
Photovoltaics (ac)	25	
Distributed Generation	72	
Program Report Potential Resources		
New Cogeneration	106	
Tidal	9	
Total Local Resources with CCA		319

SF CCA Program Remote Resources	MW	
CCA Resource Plan (Phase I)		
Wind	150	
Program Report Potential Resources		
Hetch Hetchy	40	
Total Remote CCA Resources		190
Total All CCA Resources		509

The Potrero Power Plant, owned by Mirant, currently supplies a total of 363 megawatts of power capacity to PG&E's electric grid for San Francisco and the peninsula. This region is considered constrained in terms of generation resources and transmission for importing electricity. For this reason the operator of the state's electric grid, CAISO, has signed reliability (RMR) contracts with Mirant for the full power capacity of the Potrero Plant.

The City and County of San Francisco has repeatedly expressed its desire to have the Potrero Plant shut down due to impacts from air pollution, concentrated in low income areas, as well as the City's policies to reduce reliance on fossil fuels, lower its carbon emissions, and increase its use of renewable energy. Both the City's Energy Action Plan and the Community Choice Draft Implementation Plan adopted in 2007 call for large scale development of clean energy, including renewables, distributed generation and energy efficiency. While some progress has been made toward the clean energy goals, reaching these goals in a timely manner is not likely without a San Francisco power entity, either a CCA or a municipal utility that serves the whole City, to finance the projects, provide a sufficiently large market for clean power, and to assure that the City is the beneficiary of that clean power. While the 360 megawatts clean energy target adopted for the CCA corresponds closely to the RMR capacity of the Potrero Plant, it would not in itself be sufficient to meet the RMR requirement. This has to do with the design of the 360 megawatt plan, which in itself is incomplete. This section of the report examines what energy resources can be deployed by a CCA to meet the reliability need, and how these fit with ongoing projects and plans of the City.

Significance to the CCA Program. As part of the City's decision not to approve the installation of new Combustion Turbines, the Board of Supervisors adopted and Mayor Newsom subsequently signed a resolution last summer urging the Public Utilities Commission and the City Attorney to present to the California Independent System Operator a transmission-only solution to close the entire Potrero Power Plant.[80] If such a line is built, there are potential positive or negative impacts on the CCA Program.

A potential positive impact would be to release San Francisco from dependence on its Interconnect Agreement with PG&E; but this would depend on the location chosen for the new line. If designed properly, a new transmission wire has the capability of carrying renewable energy not located in the City. A new transmission line may offer greater flexibility in coordinating with SFPUC's Hetch Hetchy electricity generation by removing barriers contained in the Interconnect Agreement. An integration on the same transmission line would make the most sustainable and sensible solution. In any case, the positive benefits would require inclusion in the CCA Program.

A potential negative impact of the transmission-only approach is that the City, which in 2003 had over 600 MW of local generation, may reduce local power generation to under 70MW, a staggering tenfold reduction making the City almost completely energy dependent on outside resources rather than it self-proclaimed goal of energy independence. The CCA Program specifically requires heavy investment in and accelerated development of a large volume of local renewable generation which if built would impact the design criteria of any new transmission line.

The City's ISO dialogue mitigation of the Portrero Power Plants could take several forms, and several other proposals have come forth, such as retrofitting and refueling the Potrero Units 4, 5, and 6 with renewable fuels.

Primary Grid Reliability Infrastructure

Potrero Plant. The current 363 megawatt plant, located in southeast San Francisco on the bayfront, contains four units: Unit 3, 4, 5 and 6. Unit 3 is a large natural gas powered generator, and the other three are smaller and powered by diesel fuel. While burning diesel fuel is much dirtier than natural gas, Unit 3 contributes by far the majority of pollution because it is operated far more hours than the diesel units. The diesel generators are limited by air quality rules not to operate more than 10% of the time, or about 800 hours per year. But in practice they run far less often, in a range between 1% and 4% of their year-round capacity. The opening of the Trans-Bay cable project in late 2010 will, according to the ISO, allow the 200 megawatt natural gas powered Unit 3 to shut down, but there will still remain the need for another 150 megawatts of in-City capacity. For reliability needs, the 150 megawatt requirement could be met in several ways.

> 1. Existing Diesel Generators. This would involve shut down of the large, gas-fired Unit-3, but continued operation of the three existing diesel units. The

[80] Resolution Number 299-08, File Number 080779, adopted June 24, 2008 and signed by Mayor Newsom on July 3.

advantages would include: pollution at the site would be dramatically cut, and, since the remaining units use diesel fuel, air quality rules would continue to mandate that hours of operation be severely limited. The disadvantage is that the power plant would continue to use a relatively dirty fuel.

2. SF Peaker Project. At this time it appears unlikely that this option would be pursued by the City. Four turbine units were given to the City as part of an environmental settlement, and for years the proposed natural gas fired power plants were considered to be the primary solution to the City's reliability needs. However, the construction of the Transbay Cable would reduce the need for power plant capacity to the equivalent of about three units, even after retirement of the main Portero unit 3. Considerable expense would be involved in putting the three peakers into operation, with the mayor's office projecting $273 million. Although part of the funding would be provided by the state's Dept. of Water Resources, the City would have financial obligations and risk for years to come. In addition, the City envisioned a third party operator that would likely have had a vested interest in selling power beyond the reliability needs. If the peakers operated at much higher capacity than the diesel units, then it is possible that they could have matched or even exceeded both the carbon and criteria emissions of the current diesel generators.

3. Retrofit Existing Plant to Natural Gas. This plan, proposed to the City and studied by Mirant, would replace the diesel units with much cleaner burning natural gas. Considerable improvement in emissions would result, especially if the hours of plant operation continue to be restricted. However, the ISO contract rules allow for two options. Under one contract plan, the plants would be limited to reliability purposes only. In general the plants would operate a similar number of hours per year as currently, in the 1% to 4% range. However, in an emergency situation, the ISO could call on the plants for considerably more time.

4. Community Energy Plan. A fourth option is to implement the community energy plans, including CCA. The City has adopted aggressive goals to improve energy efficiency and build local distributed renewable energy generation. Only a fraction of these are currently being implemented, as is discussed in the next section. A CCA has the potential to expand and accelerate the development of local clean energy. *One option would be to convert one or more of the smaller Potrero units to a greener energy source, such as biogas, hythane or hydrogen.* A CCA could facilitate this vision, proposed by the mayor, by financing the conversion or entering into a power purchase agreement. Feasibility with regard to cost and storage of fuels would have to be studied.

Existing transmission. There are high-voltage, high power capacity lines running up the Peninsula that connect the City to the rest of the California power grid. This transmission contributes most of the capacity and energy supplied to the City. Indeed, it is this heavy reliance upon long distance transmission of power, and the vulnerability associated with it, that has lead to the CAISO requiring that the City maintain local electric resources.

The transmission lines include the older power lines, part of which carries the Hetch-Hetchy electricity into the City. In addition, there have been expansions of the Peninsula transmission system over the past decade, including substation and connection upgrades and the addition of the Jefferson-Martin line.

Ongoing Reliability Improvement Project Resources

There are several ongoing projects and policies in place that either already do, or soon will, contribute to meeting local energy resource needs. These include the Trans-Bay cable, solar photovoltaics, energy efficiency, cogeneration, and peak demand reduction. In total, over the next few years, these will contribute about 500 megawatts to the City's electric resources. About 100 megawatts of this amount is local to San Francisco, though it is not clear to what extent CAISO considers these resources for reliability purposes. Considering the size of the local generation in relation to local needs, it would be worthwhile to work with CAISO to insure these local resources are adequately counted. Some of these resources are discussed in other sections of the report in more detail, but are included here for the sake of capacity inventory.

Transbay Cable. This is a 400 megawatt capacity direct current (dc) cable that will connect the current Potrero site with the East Bay city of Pittsburg. Both ends of the cable land at locations with major substations. The CAISO has informed the mayor of San Francisco that this will allow removal of just over 200 megawatts of RMR on the Potrero site, allowing the closure of Unit 3, which is by far the largest of the four units currently at Potrero.

Photovoltaics. Over the past several years over 5 megawatts of in-city solar photovoltaic generation has been installed. The SFPUC is responsible for over 1 megawatt of solar electric power, at sites such as the Moscone Center, the Port, and other locations. The current aim of the City is to install enough to bring the total up to 10 megawatts by 2010, and over 60 megawatts by 2012. The reliability factor for photovoltaics is rated at about 39% in PG&E's territory, so the total planned SFPUC goal would count as 23.4 megawatts toward reliability needs under the current utility planning.

Energy Efficiency. The next cycle of planning by SFDOE from 2009 to 2012 calls for 5.9 megawatts of energy efficiency savings from its partnership program with PG&E. This will add to the savings achieved in the current program cycle of 2006 to 2008. In addition, the City has implemented codes and standards that go above and beyond the requirements of the state or federal government. For example, residential structures must meet stringent standards, and owners are required to spend money to perform efficiency retrofits at the time of sale. The savings specifically attributable to the City's codes and standards, above and beyond SFDOE programs, are in need of quantification, but it would seem reasonable to expect that all City activities from 2006 through 2012 are likely to save at least 10 to 20 megawatts.

Cogeneration (Combined Heat and Power). A report from the SFDOElast year found a total of 60.3 megawatts of cogeneration at 26 sites within the City. The largest of these, a

30 megawatt generator, is located at the SF Airport. These provide essential base load (24/7) steady power, and contribute significantly to the local grid reliability.

Peak Demand Reduction. Investor-owned utility companies in California are required by the California Public Utilities Commission (CPUC) to obtain 5% of their peak demand from customer agreements to curtail power use during a grid emergency. These reductions are under a market-based program called Demand Response in which large customers, usually industrial, agree to cut power consumption in exchange for payments that are similar to what the utility would pay for an equivalent amount of energy. The CCA share for demand response would probably be about 40 MW. [81] Data acquisition from PG&E will be necessary to find out what the actual amount of Demand Response resource is available in the City. Currently, only the share of the City's energy supplied by PG&E is under this requirement of the CPUC; Energy Service Providers for Direct Access customers and the SFPUC are not subject to CPUC jurisdiction. It would be reasonable to require a proportional amount be adopted by the CCA.

In addition to Demand Response, utilities also can cut specified customer loads where the utility actually controls the reduction in a program called Interruptible Load. This can include a variety of measures, but one of the most widespread is cycling of air-conditioners to limit the number that come on at any given time. Each air conditioner is fitted with a control unit that can be directed from a central dispatch by the utility. Peak savings from the Interruptible Load program are additional to the savings from Demand Response, and are considered more reliable for load management.

Planned CCA Resources

The City has established 360 megawatts of definite energy resources for a CCA to build in its first implementation phase. This includes a 150 megawatt wind farm, 31 megawatts (DC) of photovoltaics, 72 megawatts of distributed generation, and 107 megawatts of energy efficiency improvements. While all of these can contribute to local reliability, there is a need to specify how this would be accomplished in a manner that is satisfactory to the CAISO.

Wind Farm. One requirement of the clean energy portfolio is a 150 megawatt wind farm. This wind farm would be outside of the Peninsula, and thus would be unable to meet local reliability needs by itself. However, wind power—most of which is generated at night during off-peak hours when the grid is not constrained—can be stored by local energy infrastructure, such as batteries or pumped water storage systems. Complementing the wind power facility with such storage technologies would allow the wind power to contribute to local reliability in this way. One potential for such a resource would be to use one or more existing SFPUC reservoir located on the peninsula for pumped storage. One question would be whether a site exists that is close enough to the City to avoid using existing transmission capacity. A second option would be to store surplus night

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[81] The Draft CCA Implementation Plan gives a peak CCA demand of 808 megawatts; 5% of this would be about 40 megawatts.

time wind power using batteries located inside the City limits. This would avoid the transmission constraints, and supply power during times of peak energy demand.

Photovoltaics. The CCA would take responsibility for 31 megawatts (dc) out of the total goal of 50 megawatts for the City as a whole. [82] As specified in the adopted CCA Draft Implementation Plan of 2007, the CCA phase 1 would be complemented by 10 megawatts of photovoltaics built by SFPUC, and an additional 9 megawatt build outside of either entity. 31 megawatts (dc) would be the equivalent of approximately 25 megawatts (ac). PG&E counts photovoltaics as worth 39% of its capacity in terms of reliability, so this would be equivalent to contributing about 10 megawatts toward CAISO need. Aligning the panels of solar systems so they are directed toward the position of the sun at the hours of peak demand might be a method for increasing the capacity value of photovoltaics. Solar systems can also be integrated with peak demand reduction methods in a synergistic manner.

Distributed Generation. The CCA plan for 72 megawatts of distributed generation would all be located within the City itself. As such they should certainly be able to contribute toward some amount of capacity needs. The exact amount will depend in part upon what types of renewable energy are chosen. In general, local wind or tidal power is likely to have significantly less reliable capacity value than their rated power, due to the intermittent nature of these resources. However, if biofuels such as biomethane or biodiesel are used, the plants could be considered 100% reliable at full rate capacity.

Energy Efficiency. The CCA has specified that it will achieve 107 megawatts worth of energy efficiency improvements. This is likely to be a combination of base load and peak load measures, but both would aim to reduce the peak demand. One major issue will be how this can be integrated with ongoing efficiency programs at SFDOE and SFPUC.

Potential Local CCA and Community Resources

There are a number of opportunities for clean and local electricity supplies that can be developed by a CCA that would add to the 360 megawatts identified for phase 1. Some of these could be accomplished near-term, such as combined heat and power and energy storage, others may require time for the technology to become available at reasonable price points and adequate volume. Options such as offshore wind, tidal and wave power, and significant expansion of photovoltaics might be pursued as part of the CCA phase 2, which is supposed to take the CCA to the point where 51% of the electricity comes from renewable sources.

Cogeneration (combined heat and power). In total 60 megawatts of electricity is generated 24/7 by combined heat and power plants in San Francisco, nearly 10% of the baseload needs of the City. According to a report by SFDOE, there is potential for at least 106 megawatts more that have been identified, and an unknown potential at other locations that needs to be explored. The new program at SFPUC to evaluate and retrofit

[82] The 50 megawatt goal is interpreted by Local Power to be dc-rated, while the ac-rated capacity would be about 40 megawatts. This was a point of confusion to SFPUC staff, and is explained here.

steam boilers represents a major opportunity for finding and developing new cogeneration. Cogeneration provides reliable power 24/7 and thus can be an important contributor to a CCA's energy supply. Because these facilities would be in the City, they would reduce reliance on the transmission grid for imported electricity. While most cogenerators run on natural gas, there is also potential for supplying these power plants with local sources of fuel. For example, the existing cogenerators at the wastewater treatment plants get their fuel from methane derived from the wastewater.

Solar Energy. The potential exists to develop far more than the 50 megawatts of photovoltaics that the Draft CCA Implementation Plan contains as a goal for the City. A major factor will be the degree to which costs of solar energy systems continue to fall and conventional electric power rates increase. One limit may be availability of space. Performing an assessment of opportunities in San Francisco, if this has not already been done, would be a significant help for future siting of photovoltaic and other solar energy systems.

Energy Storage Systems. Development of local energy storage systems can help the integration of solar and other intermittent renewable power sources into the grid, and increase the amount of local renewable energy that can be effectively used. Battery technology is now available on the market that can supply large scale power for the City during times of peak energy usage. The Sodium Sulfur (NaS) battery is produced in high volume in Japan and is suitable for storing up to 9 megawatts of power which it then can supply for up to 6 hours. [83] Several of these units could be placed in different locations around the City. They can be sited at a relatively small location; a 9.6 megawatt battery occupies approximately 70 by 160 feet, the area of a small yard or parking lot. Sodium Sulfur batteries are far less toxic than most other standard batteries, however they do operate at a high temperature and are usually located outdoors at a safe distance from structures. Battery units will need to meet environmental, safety and local regulatory requirements.

Another option that can be explored is to see whether there are potential sites on the peninsula for pumped water storage. Pump water storage facilities will face siting and environmental concerns. The ideal site would contain an existing water reservoir in order to minimize development costs and environmental impact, and a large difference in elevation for a small secondary water storage site. [84]

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[83] After reading this section, SFPUC staff stated in their Feb 11, 2009 comment document that Local Power did not include estimates of capacity costs for battery technology. This is not true; battery technology is discussed in Chapter 8, with specific capacity cost figures and comparison to other generation sources. The cost figures are based upon California Energy Commission reports and other sources. SFPUC in fact made comments on that other section of this report as well, challenging the cost figures we presented as unsourced. So it is not clear how they could both claim that Local Power did not produce such figures, and then go on to challenge the specific figures, both in the same comment document.

[84] SFPUC staff states in the comment letter of Feb 11 that Local Power discusses pumped storage on the peninsula "without recognition of environmental considerations of the protected watersheds". In our opinion this is incorrect; Local Power recommended considering sites that have existing reservoirs to minimize environmental impact. We also specified that this was an option that "can be explored…to see whether there are potential sites, implying that they would need to be evaluated for suitability.

Offshore Energy (wind and wave). While technologies for generating electricity from offshore wind and waves is still in the development stage, this is likely to evolve into a real option for San Francisco over the next decade or so. The offshore resources for both wave and wind energy are quite large, though both would be faced with environmental siting permitting challenges. As a major part of this development risk depends upon attitudes in the City itself, one course of action is to hold public stakeholder meetings to define what sort of developments would be acceptable to San Franciscans. There might also be future opportunities to partner with Sonoma or Marin County CCAs to explore siting options as well as to share the cost and common resource. There is potential to develop hundreds of megawatts of offshore power that would be delivered via a subsea cable, and thus also reduce the need for importing electricity from other areas.

Golden Gate Tidal. Recent studies have found a range of mean usable power from just a couple megawatts, to over 30 megawatts. For this report we find that the most likely range is between 1 and 3 megawatts. Because a tidal power plant would likely operate at a low capacity factor, the stated range of resource would allow building from 9 to 18 MW, but constraints on turbine siting due to bay floor geometry and the location specific resource might limit this range to about half as much. Using current technology, much of which is still in development, is not likely to prove cost effective unless a substantially larger project than URS's proposed 1.2 megawatts of capacity is installed. This power supply is intermittent, however—unlike wind—it is highly predictable. Because availability does not correlate to demand, integrating tidal generation with the rest of the generation resources may be a challenge. One option, if the costs of tidal can be brought down, is to store the power for use during peak energy demand when prices are high. However, at any scale contemplated by recent reports, the contribution of tidal energy to the CCA would be small.

Conclusion

The City has a wide range of options for meeting its grid reliability needs under the CAISO requirements, while achieving its goal of shutting down the Potrero Unit 3. However, only a few have been explored in the light of this particular need: the 400 megawatt transbay cable, the formerly proposed SF Peakers, and the current option of retrofitting the smaller diesel generators at Potrero, units 4, 5 & 6. Once the transbay cable is completed in 2010, CAISO is only requiring a further 150 megawatts of capacity for local reliability, and the three Potrero units would achieve this.

At the same time, however, other options are being pursued to meet the same local needs. These include SFPUC plans to build over 60 megawatts of solar energy, peak demand reduction efforts, ongoing energy efficiency programs of SFDOE, and City codes and standards above and beyond those of the state and federal government. A CCA offers the opportunity to access hundreds of megawatts of additional local resources, including 106 megawatts of cogeneration potential, 31 megawatts of solar energy, 107 megawatts of efficiency and conservation, and 72 megawatts of distributed generation. A phase 2 CCA program could add even more.

f. CCA Program Zoning and Permitting Issues

i. General Discussion and Recommendations

Draft rezoning and permitting ordinance to create San Francisco rollout "landing strip" so that CCA Suppliers have a rational basis for planning. Develop rezoning plan for distributed generation. Schedule public hearings to discuss and/or amend plan for Board of Supervisors approval.

Analyze loads, get access to SFPUC data and make further data requests to PG&E.

Prepare detailed rollout plan based on permitting environment, and prepare agencies.

Zoning and Permitting are key challenges for the CCA projects, because the CCA Program Design adopted by 147-07 as well as the CCA Ordinance 86-04 both require that a CCA RFP respondent must propose a rate schedule that *includes* the cost of designing, building, operating and maintaining at least 360 MW of new facilities, including 210 MW of new renewable power generation and demand side capacity inside the jurisdictional boundaries of CCSF. This requirement enables the City to finance the risk. Thus prospective CCA Supplier RFP responses must internalize these costs in order to calculate an overall cost of service. While there is as yet no rollout schedule mandated, the plan asserts that a CCA Supplier's proposed program will be feasible to the extent that its revenue bond modeling enjoys revenue adequacy; the arithmetic of H Bond repayment will depend on successful planning of a rapid rollout.

Significance to CCA Program. A key challenge of the CCA Program is to clarify the responsibilities and roles of the City and its CCA Supplier. As the financier and ultimate owner of the 360 MW infrastructure, the City is responsible for preparing a streamlined permit process for the CCA Supplier in order to help augment a timely rollout. The City's permitting environment will have a substantial impact on the time required to install energy technology at hundreds or even thousands of sites in San Francisco. As the rollout time must be predictable and timely in order for CCA Suppliers to make the required commitment to structured rates within the term of the CCA Supply Contract, it is in the City's interest to rationalize and clarify the permit environment for prospective CCA Suppliers. This should be in advance of the RFP release so that their rollout models minimize permitting time. A more rapid rollout will lower the portfolio base cost, resulting in the opportunity to offer lower, more competitive rates.

Technical issues. The permit process for CCA technology rollouts should be tailored for the planned City public works projects, so that they can be implemented by a full turnkey contractor. Under the Implementation Plan, the CCA Supplier will be designing, installing, operating and maintaining infrastructure that will ultimately become City property or property of City residents and businesses. In this sense, the project is a public works project that should enjoy a streamlined process, and given high priority by all city agencies as a critical, time-sensitive City project .This will require a special process distinct from the City's existing protocols for private sector green power facility developers.

This Program Review Report examines the existing permitting and zoning environment for each major category of renewable distributed generation and demand-side technology in San Francisco, and recommends special processes to augment the CCA Program.

The permit process for each renewable energy technology discussed in this report begins with the Department of Building Inspection. In each case, the applicant begins at the SF Permit Center located at 1660 Mission Street and completes a building permit and/or electrical permit application. As deemed appropriate, the application is then routed to various City departments, including Planning, Police and Fire.

It is important to keep in mind that these processes are only for areas that are within the jurisdiction of the City of San Francisco. They do not include the permitting requirements of the Port, of some parks that are not within the City's jurisdiction, or of State and/or Federally-owned/controlled lands.

In addition to the topics covered, the SFDOE is currently working on developing an assessment/study of solar water heating, which should be released in the next few months.

Organization

This report separately outlines the existing permitting procedures for each of the following renewable energy technologies:

- Emerging Technologies
- Solar Photovoltaics
- Wind Generation Systems
- Cogeneration
- Stationary Fuel Cells
- Tidal Power

Policy support

The *<u>Environmental Protection Element</u>* of the General Plan provides clear direction and support for renewable energy through multiple objectives and policies.

- Objective 12: Enhance the energy efficiency of housing in San Francisco
    - *Policy 13.1: Provide the energy efficiency of existing homes and apartment buildings.*

- Objective 16: Promote the use of renewable energy sources.
    - *Policy 16.1: Develop land use policies that will encourage the use of renewable energy sources.*

- Policy 16.2: Remove obstacles to energy conservation and renewable energy systems in zoning and building codes.

San Francisco's permitting environment is perhaps the greatest potential impediment to the success of the overall program. As the CCA Supplier is required to build $1.2 billion of new green power infrastructure as part of its portfolio obligation, it is imperative that the City and County prioritize significant program policy, procedure, and rule changes that may affect the technologies being deployed by the CCA Program. Even the Phase I 360 MW rollout will be a major public works project. Distributed throughout the City, solar photovoltaics are suited only to certain neighborhoods, and wind turbines to others. Renewable Distributed Generation will likely involve developments at hundreds of locations over three years. Demand reduction measures will be implemented at thousands of locations. It is in the nature of the technologies to require an intensive public planning process. While the CCA rollout is a public works project that will be mostly owned by the City and County, the private sector also will be participating in ownership of solar panels and other green power technologies. The City's intention is to maximize citizen and business ownership of their energy supply; so both the City and its people have an overarching interest in seeing the 360 MW built on-time and within budget.

ii. Special Emerging Technologies

Zoning and Permitting Stationary Fuel Cells

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Background

To date, there is one stationary fuel cell installation in San Francisco located at the United States Postal Service Embarcadero Postal Station. Because it is a federal facility, no City permits were required. In 2007, the San Francisco Public Utilities Commission approved a 600kW fuel cell at the Southeast Wastewater Treatment Plant; however, it was never built.

Permitting

Stationary fuel cell systems require a Department of Building Inspection (DBI) Building Permit and Electrical Permit at a cost that is based on the valuation of the project. The Building Permit is routed to various City departments including the Fire Marshal. The Department of Building Inspection has indicated that as with all new technologies, they would ask the applicant to provide the name of the leading professional organization supporting the technology, get in touch with that organization, and hire a respected professional at the applicant's expense recommended by the organization to guide process and make recommendations on how installation shall occur.

The Fire Marshal is concerned with fuel storage and distribution, along with emergency shut-offs. Because this is a very new technology and will likely be the first of its kind to be reviewed by the Fire Marshal, the most prudent action would be to connect San Francisco's Fire Marshal with a Fire Marshal from another jurisdiction that has already permitted the respective technology.

There are no Bay Area Air Quality Management District (BAAQMD) permits required because fuel cell systems use a chemical reaction to generate power and do not burn natural gas, and therefore are considered clean technologies.

Recommendations

Build Internal Capacity
Building internal staff capacity, including the appointment of a point person, is the most important first step in addressing stationary fuel cells; interviews with CCSF staff indicated that no one within the organization has been assigned responsibility for stationary fuel cell development. The Fire Marshal has also been identified as one of the most important people to include in this discussion.

Create Stationary Fuel Cell Task Force
There is very little direction from City staff in terms of Fuel Cell systems, thus making it difficult to make specific policy recommendations. The best course of action is to establish a Task Force to look specifically at stationary fuel cell technologies and identify how they can best be rolled-out in San Francisco. The task force should look at the following areas:

- Permitting – Create permit guidelines for interested applicants
- Cost and incentives
- Public awareness and demonstrations

Creating permit guidelines for the public is a very important first step. This does not need to be as formal as an administrative policy or bulletin, but should spell out what the City is looking for and how the applicant can meet that criteria. The guidelines should incorporate the following criteria:

- Streamlined process – Priority review. Administrative review versus discretionary review wherever possible.
- Reduced fees
- Transparent permit procedures and review criteria

Recommendation: Adopt a resolution that directs the SFDOE to appoint a staff point-person who is responsible for the development of stationary fuel cells; and, create a task force (incorporating the above mentioned criteria) that is responsible for looking at permitting, cost and incentives and public awareness/demonstrations.

Zoning and Permitting issues for Other Emerging Renewable Technologies

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Background

In many cases, new technology is not addressed by current codes and administrative procedures. The Department of Building Inspection (DBI), the department charged with application intake and technical review, plays a very important role in this process. In some cases, the SFDOE plays the role of advocate for applicants who are not effectively communicating with the DBI, or who do not understand the process for doing so. At times, this puts the Department of Building Inspection and Department of the Environment at odds.

Permitting

Technical Assessment of Emerging Technologies

The Department of Building Inspection frequently works with applicants who are proposing to integrate new technology into projects. Many times these technologies are not addressed by the building code but still need to be held to the same standards in order to protect the health, safety and well being of the general public. The same process is used for permitting emerging renewable energy technologies. To do so, the applicant must prove that the new technology meets the equivalence of the prescriptive code by adequately addressing:

- Suitability
- Strength
- Effectiveness
- Fire resistance
- Durability
- Safety
- Sanitation

In order for the Building Inspector to make these findings, specifically those for strength and durability, he or she refers to outside organizations that separately test and 'list' products. Testing is done by organizations like ASTM (American Society for Testing and

Materials) and ANSI (American National Standards Institute) and is focused on individual parts that make up a larger product. "Tested" components are then assembled to create a product. At that point, the assembled product must demonstrate compliance with the appropriate safety requirements and demonstrate that it has a program in place to ensure that each copy of the product complies. One prevalent listing organization is Underwriters Laboratories, commonly known as UL.

Once a product has a UL listing (or equivalent), the Building Inspector can make the necessary findings for equivalence and can issue a permit. In the field of renewable energy technology, this can prove to be somewhat difficult, because testing and listing is extremely expensive and time intensive. In the case of wind turbines, many companies are using "tested" components but do not have the resources to have their assembled turbine "listed".

When a respective technology has tested components but is not listed, the Department of Building Inspection is open and receptive to allowing demo and model projects, but will not approve a project outright. The department monitors the strength and durability of the demo projects and may choose to allow a particular technology if it performs well over time.

Building Inspection Administrative Procedures for Emerging Technologies

Laurence Kornfield, Chief Building Inspector, believes strongly in maintaining a flexible set of permitting procedures for developing technologies, including solar, wind, cogeneration and fuel cells. Over time, as a large volume of permits are processed for an individual technology, the procedures are tweaked and modified until staff is comfortable with codifying them into an Administrative Bulletin. An Administrative Bulletin is a cut-and-dry set of procedures, adopted by the Building Inspection Commission, which specifically states what needs to occur to permit a respective technology.

A draft set of procedures has been developed for solar permitting; however, each of the other renewable energy technologies addressed in this report are reviewed on a case-by-case basis. The draft procedures will continue to evolve until the Chief Building Inspector believes that the process is ready to be introduced for consideration as an Administrative Bulletin.

Overall Permitting Recommendation for CCA Program

Consider the Need for a Rezoning Ordinance for CCA City- and Customer-Owned Green Power

The significant change proposed is that the City's permitting processes reevaluate its zoning and permitting processes and rules for certain kinds of renewable energy facilities (such as wind power) that are part of the City's CCA Program.

***Recommendation*: Draft a rezoning ordinance to create** San Francisco's 360 MW rollout "landing strip" so that CCA Suppliers are provided a rational basis for planning their rollouts. In any event, the Program Basis Report should include work on a rezoning plan for various renewable distributed generation technologies, and schedule public hearings to discuss and/or amend the plan for submission to the Board of Supervisors for approval.

Permit Center

As the permit hub, the SF Permit Center at 1660 Mission Street is where members of the public interact on a daily basis with City staff. Many times this is the first point of contact between the public and City staff, and is therefore responsible for creating first impressions. LPI staff performed an unsolicited audit to get a feel of the process from the perspective of a member of the public, and was disappointed by the poor service and short temperament of staff. The general feeling was that of chaos and confusion, with no help from counter staff at the Information desk – a member of the public would certainly be overwhelmed. No information was available for renewable energy technologies, the permit process required for a subject technology or the fees associated with a given process.

Recommendation: Direct the Permit Center to improve the physical layout and signage to be customer friendly and easily navigated. Mandate good customer service from Permit Center staff. Train staff in renewable energy technology permitting requirements and fee structures. Have take-home resources available for various City programs, incentives, policies, etc.

Discretionary Review

The Discretionary Review process is unique to CCSF; it allows any member of the public to request a Planning Commission review of a subject building permit, thus turning what should be an administrative review process into a discretionary review process. Thirty day noticing is required for any building permit in a Residential and/or Neighborhood Commercial zoning district, as well as in historic overlay districts. The process makes it virtually impossible to streamline any project that requires a building permit.

Recommendation: Pass an ordinance that exempts renewable energy generation devices from discretionary review. A list of allowed renewable energy generation devices will need to be included in the ordinance; the Zoning Administrator should be given the authority to add additional technologies to the list as they arise. This action would not take-away necessary checks-and-balance because CCSF's process allows building permits to be appealed to the Planning Commission.

Renewable Energy Advisory Group

A Renewable Energy Advisory Group made up of staff from the CCSF, SFPUC and LAFCO should be created as an advisory group to the LAFCO Commission. This would establish a high-profile group of city staff responsible for streamlining various processes while assuring the health and safety of the public. The group would be expected to meet regularly to discuss interdisciplinary solutions to encourage renewable energy expansion, make policy recommendations to implement subject solutions, and regularly report activity to the Commission. It would give the Commission oversight and direction to a cross-section of departments and divisions, for the purpose of expanding renewable energy technologies.

Recommendation: Adopt a resolution that establishes a Renewable Energy Advisory Group, responsible to LAFCO, made up of staff including the Fire Marshall, Chief Building Inspector, Senior Electrical Inspector, Zoning Administrator, Senior City Planner, Renewable Energy Manager, and management-level staff from LAFCO, SFPUC and the City Attorney and City Assessor's offices.

Renewable Energy Website

Currently, there is no central hub that exists for renewable energy permitting, applicable CCSF policies, etc. It takes a lot of time and energy to determine what is required by each department, who to talk to at each agency, and what process needs to be followed for any particular project. Several City departments have renewable energy sections as part of their websites; however, a central, user friendly website does not exist. The creation could substantially bridge the large information gap that currently exists. It may be a good first project for the Renewable Energy Advisory Group (with staff or consultant support).

Recommendation: Adopt a resolution that directs LAFCO, or an appropriate agency to develop a comprehensive renewable energy website.

Permit Fees

The current fees associated with permitting renewable energy technologies are calculated based on a valuation of the project. The technologies generally have large upfront costs and therefore have high project valuations, which lead to a high permit cost.

Recommendation: Adopt a resolution directing the Department of Building Inspection to amend their fee schedule for renewable energy technologies:

- Set a below-market, fixed fee for Building and Electrical Permits for wind generation devices
- Set a below-market, valuation-based fee for Cogeneration and Fuel Cell technologies

Adopt a resolution directing the Department of Planning to amend their fee schedule for renewable technologies:

- Wave the valuation-based fee for Certificates of Appropriateness that apply to renewable energy devices proposed to be mounted on, or require the alteration of a historic structure.
- Set a below-market, fixed fee for Conditional Use permits for wind generation devices that are over 40-feet in residential districts

5. CCA/SFDOE/SFPUC Energy Efficiency Partnership, and the role of the PG&E Energy Efficiency Partnership

Ordinance 147-07 and 86-04 require prospective CCA Suppliers to build at least 107 MW of energy efficiency capacity in order to qualify in the CCA RFP process, and both AB117 and California Public Utilities Commission (CPUC) regulations provide CCAs with an opportunity to seek to become administrators of Public Goods Charge Funds for Energy Efficiency programs (PGCEE Funds) that are now paid monthly as a non-bypassable monthly charge by San Francisco ratepayers to PG&E and administered by PG&E.

The Draft CCA Implementation Plan adopted by 147-07 provides that LAFCO, SFPUC and the City Attorney "shall engage the CPUC to reopen this issue" and states that the Board of Supervisors may vote to discontinue the partnership by resolution at any time, but this has not yet occurred. CCSF's legal team has not yet to our knowledge petitioned the CPUC to allow CCSF to administer these funds for a CCA program, although CPUC Commissioner Dian Grueneich has recently invited interested parties to submit comments on the subject of CCA administration of PGCEE funds, providing a timely opportunity to get started on this important planning issue.

This Program Review Report recommends that CCSF urgently petition the CPUC and commit resources toward becoming an administrator of Energy Efficiency PGC funds starting in 2010 according to the timeline ordered by Ordinance 146-07 and 147-07. *Rather than terminate, the PG&E Partnership will have to be changed*, so that the portion dealing with electric power is transferred to full CCA administration managed through SFDOE. The natural gas efficiency partnership would continue within the same framework as the current program. It is important that the planning, budgeting and administrative adjustments be made to ensure a seamless transition of SFDOE staff to its management role in the rollout of 107 MW of Energy Efficiency and Conservation measures. *The efficiency rollout is required of the*

AB 117 allows CCAs to apply to be administrators of efficiency funds – share is according to energy use.

Funds allocated from public good surcharge on customer bills.

CPUC annual IOU efficiency budget $800 million; SF CCA about 2% of IOU energy; SF share ~$17 million per year

SF DOE has energy efficiency partnership with PG&E. Projected $5.9 million in 2009, $16.7 million over 3-year program cycle.

SF DOE has energy efficiency expertise; CCA should build upon existing program.

City should pursue discussions with CPUC and participate in hearings to assure fair share for CCA efficiency funds.

LAFCO should petition CPUC for administration of EE Funds; CCSF should devise schedule for earliest possible transition to CCA efficiency program, ensuring seamless transition for SFDOE staff and customer operations.

CCA Supplier by the CCA Program, and thus establishment of the role of SFDOE within the CCA program in a timely manner will be essential for ESP bidders.

Technical Issues. Currently, SF Department of the Environment (SFDOE) is in the process of committing City ratepayer funds in a contract with PG&E, and the CPUC is in the process of approving such contracts for three years into the future – with a budget of $14 - $18 million. When approved, this will effectively lock up funds that would otherwise be available to the CCA Program. SFPUC staff suggested that the CCA would most appropriately limit its role to marketing more aggressively the PG&E Energy Efficiency Program and spending marketing dollars to do so. This however is inconsistent with the City's adopted policy and would violate Ordinance 147-07. The ordinance requires SFDOE to prepare to end its Partnership with PG&E's electricity efficiency program upon initiation of CCA Service, and to undertake a transition to the management role defined by the Draft CCA Implementation Plan. This will enable the City to seek to be an administrator of PGC EE funds that will help pay for the 107 MW Energy Efficiency rollout. Since this rollout is required for the CCA Supplier, funding certainty will be important for the potential Supplier bids.

Significance to CCA Program. Ordinances 86-04 and 147-07 require CCA Supplier bids to include the cost of installing 107 MW of energy efficiency and conservation measures throughout the city. This is the most cost-effective element of the portfolio and represents a large local resource. While the City's CCA RFP Process is expected to initiate CCA Service in 2010, the SFDOE PG&E Partnership may provide funding commitments during at least the first year of the CCA Program. SFDOE staff have indicated that the recently negotiated contract contains provisions to the effect that the City may terminate the PG&E Partnership agreement, effective immediately, at any time, but also request that this not be done until access to the funds is secured. *This underscores the importance of securing CPUC approval of CCSF Energy Efficiency PGC Funds administration.*

Availability of the PGCEE funds is critical to minimize the debt burden of the 107MW rollout of resources, and will reduce the cost of achieving the CCA Program's accelerated 51% RPS. Energy Efficiency is already cheaper than coal, such that the immediate savings from energy efficiency measures will actually lower the overall cost of providing power to San Francisco. AB117 directed the CPUC to provide CCAs with an opportunity to administer Energy Efficiency Public Goods Charge funds because energy efficiency is a critical resource in planning long-term energy use. *The CPUC indicated it will act on the matter of CCA EEPGC funds when petitioned by a CCA to do so.*

Clarifying the PGCEE funds issue is an important part of the CCA Program Basis Report and Request for Proposals, because prospective CCA Suppliers must know what funds to expect or not expect to be available, and on what basic schedule, in order to create revenue adequacy models for their proposed 360 MW rollout implementation, as well as their 51% RPS implementation.

Recommendation. CCSF should initiate a protocol to modify SFDOE's recently renewed PG&E partnership, which occurred under SFPUC administration and approval process.

CCSF should, as soon as possible, petition the California Public Utilities Commission to directly administer Energy Efficiency Public Goods Charge Funds to support the CCA Program. These funds are paid by participating San Francisco customers, and the CCA should seek its proportional share of these funds according to law, beginning in budget year 2010,. The CCA represents about 2% of the electric power consumed in the state's IOU service territories, and the CPUC 2008 budget for efficiency is about $800 million. Thus the share paid by prospective San Francisco CCA customers into the PGC fund for CPUC efficiency programs would be approximately $16 million per year. The formula for allocation, however, may be established by number of customers.

The City should invite other California municipalities and counties to cooperate with the City in its regulatory efforts. A California Public Utilities Commission workshop on CCA administration of energy efficiency public goods charge (PGC) funds was scheduled for November 2008, and comments have been solicited from interested parties. Furthermore, other CCA managers, such as Kings River Conservation District General Manager David Orth, have expressed an interest in collaborating with other CCAs on this issue at the CPUC.[85]

[85] See Appendix I – Energy Efficiency in San Francisco

6. Ongoing Transbay Cable Project

a. Trans Bay Cable Project Overview

i. Description of Project and Need

The Transbay Cable (TBC) is an energy transmission infrastructure project chosen by CAISO to provide reliable energy to the City of San Francisco. The CAISO determined in early 2005 that the northern San Francisco Peninsula needed an additional transmission line to ensure energy reliability in 2010 and beyond. In September 2005, after a lengthy stakeholder process, the CAISO selected the TBC over competing alternatives as the best transmission solution for the northern San Francisco Peninsula.

A stated objective of the TBC is to "*enable San Francisco to rely less on in-city generation*." San Francisco does not currently generate enough power for its own residents and businesses, and must rely on outside transmission lines to deliver some of its electricity. The TBC will receive its power from the PG&E Pittsburg Substation. The Pittsburg Substation receives power through transmission lines from many power plants in California and from a variety of energy sources, including renewable energy sources such as hydropower, geothermal and wind. Upon commercial operation of the TBC project, the CAISO will have the authority to transmit energy over the 53-mile TBC DC line to the Potrero substation in San Francisco.

400 MW Transbay Cable, and other transmission links, could allow CCA access to wind power and other resources in Solano and beyond.

FERC gives access priority to resources with lowest variable cost, usually renewables.

CAISO considers SF Peninsula "transmission constrained".

Past transmission upgrade include Jefferson-Martin line that allowed closure of Hunters Point

City goal to close Potrero requires replacement: using generation, transmission and demand reduction.

Recommendation: SF should investigate renewable generation projects to use the Trans-Bay cable, including a wind farm

Once operational in 2010, the TBC will deliver up to 400 megawatts of power from the electrical grid in Pittsburg to San Francisco. 400 megawatts is sufficient to supply approximately 40 percent of San Francisco's total peak capacity needs, and potentially a majority of its energy (kilowatt-hour per year) needs. The CAISO determined that the new transmission line must begin service by 2010 in order to fulfill the city's immediate energy needs. According to the project website, the TBC project will allow for the shutdown of Potrero Power Plant Unit 3 once it is operational.

ii. Financing, Control & Ownership

The TBC is being financed by a cost-based infrastructure recovery charge approved by the Federal Energy Regulatory Commission (FERC) and CAISO in 2005. The project is under construction and expected to be operational in 2010. The cost of the TBC will be borne by all California IOU customers. CAISO will have complete operational control over the TBC.

TBC is a public-private partnership between the City of Pittsburg and Babcock & Brown. Babcock & Brown is responsible for developing and financing the project in cooperation with the City of Pittsburg. Once operational, the City of Pittsburg will take ownership of TBC assets. Babcock & Brown will retain ownership of the TBC transmission rights, which will be turned over to CAISO for operational control of the TBC.

b. Transmitting City of San Francisco Wind Power or Solar Power Generated in East Bay Over TBC

While the CCA will aim to optimize local energy resources, it is still expected that a significant portion of its power will be imported from outside the City. In particular, the planned 150 MW wind farm cannot feasibly be placed in the City. The TBC may open up access to the wind resources of Solano County, biomass resources in or near the delta, as well as other possible renewable energy resources.

i. TBC Will Be Open Access

CAISO is operator of most of the state's electric grid, will be responsible for controlling the dispatch and access of power supplies to the TBC. All transmission lines under FERC control are required to be open access. This includes transmission lines owned or operated by the CAISO and PG&E. Open access means that generators of any fuel type are eligible to interconnect and contract for unsubscribed capacity.[86]

[86] FERC News Release, *Commission Acts to Remove Regulatory Barriers to Renewable Energy Development in California*, Docket No. EL07-33-000, April 19, 2007, p. 2.

ii. FERC/CAISO Policy on Transmission Access for Intermittent Renewable Energy

Unlike a natural gas power plant that can be turned on and off at will, certain types of renewable power plants only generate electricity when natural resources are available. Wind, run-of-river hydro, and qualifying facilities (QF) are the predominant types of intermittent resources. Their output levels cannot be controlled by the dispatcher, and there are contractual, regulatory, or cost factors that require these resources to be accepted in full whenever they are available. These are referred to as “must take” resources. Forecast schedules for these types of electric generators are placed at the top of a prioritized list called the “dispatch stack” and modified in real time to reflect actual production. Power plants that can vary their output over time to match changing needs on the grid are called “load-following” resources, and these are dispatched to compensate for the relative availability or absence of intermittent, must-take resources.[87]

iii. Concept of Economic Dispatch

It is FERC/CAISO policy to facilitate economic dispatch of generation resources, which represents an attempt use the lowest cost resources first and only bring more expensive power supply online when they are needed. “Economic dispatch” is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. In practice, however, the measure of cost is not the full cost of power, but only the variable cost of the power plants which increase or decrease according to how much electricity they generate. Economic dispatch reduces total variable production costs by serving customer load using lower-variable-cost generation before using higher-variable cost generation (i.e., by dispatching generation in “merit order” from lowest to highest variable cost).[88] The primary variable cost in a fossil fuel plant is the fuel cost, which in the case of a natural gas plant can account for the majority of the cost of generating electricity. Renewable energy resources like wind and solar have no fuel cost and therefore a near zero variable cost. As a somewhat unintended result, the renewables will be given first priority on the power lines.

Economic dispatch principles and operation are the same in both regulated utility operations and centralized wholesale markets. In centralized markets, the merit order of available resources is determined using offer schedules for each resource rather than the variable production costs that are used to dispatch a set of utility-owned resources.

iv. Economic Dispatch Problems

[87] U.S. DOE, *The Value of Economic Dispatch - A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, November 5, 2005, p. 19.
[88] Ibid, p. 4.

Non-utility generator (NUG) complaints about economic dispatch revolve around allegations that vertically integrated utilities use their dispatch processes to favor utility-owned generation over non-utility owned generation. However, because economic dispatch is a relatively mechanical process, it appears that many of the concerns that NUGs see as ineffective economic dispatch are more accurately viewed as rules and practices that exclude NUGs (and other resources) from the economic dispatch stack. These practices include determinations of whether NUGs receive long-term contracts to sell their production to load-serving entities, whether they can secure sufficient transmission capacity to deliver their production to host utility loads or more distant purchasers, and whether NUGs provide sufficient operational flexibility to provide maximum operational value to the grid.[89]

v. Hetch-Hetchy Interconnection Agreement with CAISO Is Model for Interconnection Agreement for City-Owned Renewable Power

The Hetch Hetchy Project is operated by the SFPUC through Hetch Hetchy Water and Power. The City is also a transmission customer of PG&E consistent with the interconnection agreement on file with FERC as PG&E Rate Schedule FERC 114. The interconnection agreement provides the City with firm and non-firm transmission rights on PG&E's system. Hetch Hetchy Water and Power is responsible for the scheduling and transmission of power in a manner consistent with the rules of the CAISO tariff.[90]

In 1913, the enactment of the Raker act defined the provisions under which the City could construct and operate a water supply system within the Tuolumne River watershed. The Raker Act prohibits the SFPUC from ever selling power to "any corporation". As a result, the SFPUC cannot sell power to the CAISO.

The CCSF has in place an interconnection agreement that permits the transmission of electricity generated by a remotely-located CCSF generation facility to the CCSF load center over the CAISO-controlled transmission grid. The CCSF-PG&E interconnection agreement pre-dates the existence of the CAISO, and includes conditions that would not be included in a current interconnection agreement.

If the SF CCA chose to pursue a CCA-owned wind farm in Solano County, the CCA would require CAISO approval to build the gen-tie from the wind farm to the network facility (the transmission substation). This approval would be granted based on the results of a system interconnection study and interconnection facilities study. However, the interconnection cost to CCSF could be prohibitive if there are already generation projects ahead of CCSF in the CAISO project queue that would consume the entire spare capacity of the existing substation.

Historically, this procedure would shift the cost burden to upgrade the substation to accommodate more powerflow at that substation to the proponent of next project in the

[89] Ibid, p. 6.
[90] SFPUC, response to Local Power question 2C.

queue. However, the CAISO recently incorporated a new format where projects in the queue are clustered such that the upgrade would be borne by a group of project proponents instead of a single entity. This "first-come first-served" CAISO approach to grid access would tend to result in lower of transmission access costs for early projects. Conversely, projects that delay in filing for transmission access with CAISO could experience higher transmission access costs.

The CCSF generation source would then have access to the CAISO grid for transmission of this power to CCSF. If CAISO anticipates next-day congestion at the point where CCSF generation is entering the CAISO-controlled system, such that some generators entering the system at the same point may be curtailed unless they pay a premium to avoid curtailment, the SF CCA would have the opportunity to pay that premium to ensure the wind power is delivered to the load.

c. San Francisco CCA Will Receive RPS Credit for City-Owned Wind or Solar Generated in East Bay Area but Not Transmitted Over TBC

The primary objective of the renewable energy component of the CCA plan is to reduce the greenhouse gas footprint of the city's power consumption. That objective will be achieved whether or not city-owned wind or solar generation assets in the East Bay or Sacramento River areas is physically transmitted to San Francisco via the TBC. The city will take credit for the production of the renewable energy in either case. A case in point is SDG&E's recent power purchase agreement for 200 MW of Montana wind power. SDG&E will take full credit under the Renewable Portfolio Standard (RPS) for this wind power, though none of this wind power will be physically delivered to SDG&E service territory.

The Bay Area is drawing-in power from outlying areas as it is the regional load center in Northern California. For this reason, power generated at a CCA-owned wind farm in Solano County would be assisting in meeting the power demand of San Francisco in a general sense. If this power flows directly to the Pittsburg substation, the starting point of the TBC, then some component of the power generated at the wind farm would be directly contributing to power flow over the TBC.

7. Ongoing In-City Distribution Developments.

The Board of Supervisors placed an initiative on the November ballot to authorize an acquisition of PG&E's existing electrical distribution system within the jurisdictional boundaries of the City and County, as well as potentially some substation and transmission infrastructure. While voters rejected the initiative, there are a number of ongoing and incipient City projects concerning distribution, or that rely on distribution for operations.

SFPUC – Isolation of San Francisco from PG&E Grid. Barbara Hale reports that SFPUC has negotiated a Federal Energy Regulatory Commission (FERC) agreement with PG&E, under which new switchgear will isolate the City's system from PG&E, which involves a wholesale distribution agreement.

2008 Supervisor Daly Ordinance to finance power distribution in all City Fiber Trenching projects. Supervisor Daly has proposed legislation that would provide for laying power distribution cable in all City fiber trenching projects citywide. More recently, the Supervisor has proposed a third category of public financing for power distribution facilities in San Francisco based on Mello Roos bonds via a Community Facilities District. "Local Goals and Policies for Community Facilities Districts" (CFDs) has not yet been adopted by the Board of Supervisors, but in a recent conversation, Commissioner Daly indicated that he would like to pursue this course, sent us copies of his legislation, and said he considered it "ongoing distribution" developments mentioned in the scope of this Program Report.

The Daly legislation would have the City adopt local goals and policies concerning the use of the Mello-Roos Community Facilities Act of 1982 (the "Act"), to establish a new community facilities district ("CFD") under the Act. The legislation adopts broad goals for "financing of public facilities and services in connection with new development projects as well as in previously developed areas where the City is seeking to foster and/or leverage additional improvement and maintenance of public infrastructure and other public

SFPUC negotiated agreement with FERC to isolate City load from PG&E system.

Mello-Roos may be changed to allow financing of electrical distribution.

If distribution is paid for by H-bonds, facilities would be limited to renewable power.

Recommendations: City should examine the use of H Bonds and other vehicles to finance, if necessary, distribution lines within CCSF jurisdictional boundaries.

City should examine distribution opportunities for Golden Gate tidal line, Lennar and Treasure Island, and innovative opportunities to incorporate City-owned renewable power plants into design of developments.

City should investigate legal ramifications of distribution system ownership and funding, and work to get state law amended to allow Mello-Roos funding.

assets, covering City and consultant costs incurred in the evaluation subject to the approval requirements for such appropriations under the City Charter. Subject to the exceptions set forth in Sections 3.3 and 3.4, the improvements eligible to be financed by a CFD must be owned and operated by the City, by a public agency or public utility, and must have a useful life of at least five (5) years, except that up to five percent of the proceeds of an issue may be used for facilities owned and operated by a privately-owned public utility.

The ordinance also expresses support for financing under the Act of infrastructure and other facilities that provide the opportunity for San Franciscans to participate financially in the creation of self-sufficient and/or environmentally friendly "Green Communities".

While there are barriers in Mello Roos to financing electrical distribution facilities, state legislation has been prepared to change this. No such prohibition exists for using Mello Roos as a financing instrument for thermal distribution facilities, such as District Heat, in order to replace natural gas-based heat and refrigeration systems with efficiency-based heat recovery technologies, a variety of which present a major economic opportunity for heat recycling that may have special interface applications for the Co-generation project on existing natural gas boilers that is proposed in this Program Report.

The significance of this ongoing discussion about power distribution in the city is the potential role of the SFPUC or another agency installing new, parallel distribution infrastructure for key projects, such as an islanding project, infrastructure to leverage the Hunters Point and Treasure Island SFPUC Microgrids, or distribution substation infrastructure for a potential Golden Gate Tidal project.

The use of distribution is a back-up option that need not be categorized as a municipalization, because it could potentially involve the installation of new lines in order to provide services that PG&E may not be required to or willing to provide at acceptable terms, rather than the acquisition of existing PG&E lines. If financed by the H Bond Authority such distributed power components would be limited to transacting renewable power or capacity.

LPI has requested SFPUC data on large natural gas customers in order to identify candidates for cogeneration on existing boilers, but has not received this data as of the submission deadline.

Hunter’s Point Shipyard (HPS) – Lennar and SFPUC Distribution System

Under a 2007 agreement, the City will serve the electric load at HPS. The City will design, supply and install electric primary and secondary Distribution line facilities, including conductors, transformers, and other needed equipment within substructures and conduits provided by Lennar and deeded to the City. The City committed to design, supply and install Electric Service facilities that extend form Distribution Line facilities to customers’ service termination facilities within substructures and conduits provided by

Lennar or the Vertical developer, which will be responsible for furnishing and installing the joint trench, electric distribution conduits and substructures[91]

SFPUC is spending $10,025,215 on Parcel A of the Hunters Point Naval Shipyard, installing a new distribution system and meters to provide service to Lennar's new loads, including an electric distribution line extension and service connections, including switchgear and residential meters. Another $1.862,785 will complete the capital project in 2009, but the project will have ongoing costs for four on-budget positions for operation and maintenance functions.[92]

The SFPUC has spending authority, and has signed an agreement with Lennar, enabling Lennar to bypass the 34% ITCC tax, and the City will receive the distribution infrastructure installed by Lennar at a shared cost, rather than PG&E. Lennar has already designed the power distribution system, of which the City has engineering drawings. Lennar will sell the lots to vertical developers in Spring '09. Under the agreement, SFPUC must provide power service to Lennar ratepayers. According to the Financial Services Project Budget Report, "(t)he capital infrastructure will support "green" power and other renewable options."[93]

The details have yet to be decided. SFPUC has provided Lennar specifications for "Solar-Ready" homes but has not yet determined whether or to what extent to finance actual renewable capacity infrastructure on these new buildings. Assistant General Manager Barbara Hale said the SFPUC is still deciding "whether to use a PPA arrangement or a direct investment" on renewable capacity in BHS.

The Lennar agreement provides that the City should provide Utility Design Guidelines for substructure work and prepare and submit service connection requirements for Parcel A consistent with a mutually agreed construction schedule, and provide field service to operate and maintain the system, and obtain regulatory approvals. Given the City's active role in designing and planning the infrastructure, the CCA Program should seek to evaluate specific opportunities for technology development in BHS.

The Draft CCA Implementation Plan adopted in 2007 had an extensive section on the subject of "islanding" as an opportunity for renewable capacity green power storage sharing, and potential energy security sharing. The Hunter's Point project provides an opportunity for lower-cost Building Integrated Photovoltaics and other integrated power systems that could potentially generate onsite renewable generation to free up more Hetch-Hetchy capacity for CCA customers, and also create significant opportunities to build CCA-based capacity onsite. Given the City's ownership of this grid, HPS is a significant opportunity for both islanding and renewable power generation for Bay View Hunter's Point, Portrero, and ratepayers Citywide. As the designs for this development

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[91] Agreement between the City and County of San Francisco and Lennar/BVHP, LLC for provision of Electric Service to Parcel A of the Hunters Point Shipyard Development, Execution copy, 2-14-00, page 9.
[92] Financial Services Project Budget Report, Energy Services CUH979, SFPUC
[93] *Ibid.*

are underway, the CCA Program should urgently investigate specific opportunities for the City to take full advantage of this resource.

Treasure Island

Like HPS, Treasure Island is both a new Hetch Hetchy customer in San Francisco and also a potential platform for CCA Portfolio investments. SFPUC is currently the power provider to the island. While Treasure Island is not as far advanced in redeveloping as Hunter's Point, the island is arguably equal in its potential as a building and site-integrated renewable energy resource for the community, rather than simply an addition of load to the Hetch-Hetchy system

According to Assistant General Manager Barbara Hale, the SFPUC has no Service Agreement yet, but the City has approved some development documents. A new transmission cable has been installed from East Bay Port of Oakland Davis Substation to Treasure Island.

MUNI Distribution System

LPI believes that MUNI's distribution system and or rights of way should be investigated as potential platform for targeted renewable distribution and islanding lines.
MUNI owns its wires, and purchases Hetch-Hetchy power from the SFPUC.

LPI has requested data on MUNI's infrastructure and energy use, and hopes to receive it in time for the Final Draft.

8. Smart Grid and Key Emerging Technology Opportunities

While new developments like Hunter's Point and Treasure Island present unique microgrid and micropower distribution and capacity integration opportunities, Smart Grid opportunities for the CCA Supplier are citywide; every San Francisco home and business will soon have smart meters, whose time-of-use based measurements and automation capability will help augment the City's demand-oriented approach to portfolio design. Even low-cost thermal control opportunities are possible, meaning that power meters can be used to automate not just electric refrigeration but natural gas-based heating systems. Demand-side technologies, onsite capacity technologies and storage opportunities, immensely enhanced by the City's analytical access to customer usage data, creates the opportunity to mainstream Smart Grid technologies to the extent of making them ubiquitous throughout the City rather than an isolated program for early adopters. [94] With the opt-out relationship and ratesetting authority of CCA, every home and business in San Francisco is eligible for technologies that most Americans have read about but never seen; the CCA is uniquely poised to help CCA Suppliers offer such options to all participating ratepayers, and use the City's H Bond financing for them, where appropriate.

CCA 107 MW Efficiency and Conservation requirement– involves choice of technology

CCA 72 MW Distributed Generation requirement could lead to development of fuel cells, energy storage, urban wind, etc.

CCA portfolio should remain open to future emerging technologies, such as tidal, wave, and deep water offshore wind.

PG&E will install Smart Meters in San Francisco; CCA might benefit if meter design can facilitate operation of urban green network.

In short, opportunities for Emerging Technology in San Francisco's CCA Program are rife. One insight into understanding the nature of the Smart Grid opportunity of CCA, is to understand that CCAs, unlike utility companies, are demand-side entities, defined under law as organizations of ratepayers to negotiate together. Being customers, they are less concerned with protecting the status quo system and more interested in innovations, particularly innovations that reduce energy use and pollution. Second, because CCAs are not invested in legacy assets of the existing power infrastructure, they are freer to invest in technologies that reduce energy use. By investing in 107 MW of

[94] SFPUC staff expressed that they were "unclear" about these Smart Grid technologies, including how a CCA could utilize technologies that would be owned by the local utility. However, use of Smart Grid networks need not imply ownership of the grid. SFPUC seems to be confusing the wide range of potential Smart Grid technology, with the Smart Meters that will be owned by PG&E. Separate metering, communications, and control devices, owned by customers or the CCA, can be installed at sites where there are CCA owned or controlled demand side technologies. Separate dedicated meters are customary, for example, at sites that have photovoltaic systems receiving performance based incentives from the CSI program. And new appliances that are certainly not owned by utilities are now being manufactured to be smart-grid ready.

demand side technology and 103 MW of renewable distributed generation, San Francisco has placed the Smart Grid at front and center of its core energy strategy. The Draft Implementation Plan contains extensive discussion of "Islanding" and other cutting-edge technology innovations, and chose to leave the choice of technologies to bidders, giving a full range of technology and site design control to prospective CCA Suppliers so that they can manage and their costs and accept responsibility for structured rates - an approach that Michael Bell Management Consulting subsequently endorsed in its review of the Draft Implementation Plan and RFI responses.[95]

As demand-side entities, CCAs are uniquely positioned to embrace the "virtual capacity" approach to energy at the retail level, paying for "virtual capacity" on a levellized cost basis as if it were the power being saved. Because demand response and other Smart Grid technologies already provide power at prices lower than equivalent coal-fired generation capacity, aggressive deployment of such technologies by a CCA Supply will not result in an increased cost base. Quite the contrary, Smart Grid is a profit center (not a "public benefit program") for CCA Suppliers.

There are numerous opportunities for using innovative technologies in a San Francisco CCA. These technologies can be used to generate power, store it, and manage the local grid in ways that help increase reliance on low- or zero-emission resources. During the first phase of CCA implementation, product availability—in our opinion— should be sufficient to deploy fuel cells, battery storage and certain elements of a smart grid. [96] There is projected to be production capacity to build out local infrastructure using these technologies at significant scale. The City will need to follow developments in pricing and products to evaluate to what extent it will make sense to develop such local projects. Other technologies to tap local resources, such as tidal, offshore wind, and wave power generation are currently under development, and San Francisco could position itself to become a test site over the next decade. Coordination with universities or research institutions could help make development of these resources feasible, especially if the City seeks financial support in the form of grants, rebates, tax credits or federal zero interest bonds.

a. Emerging Technologies

The following technologies are at different stages of development. Some of them are ready to be deployed today, while others will become available over the next decade. Low or zero interest financing available to a CCA, as well as federal grants and tax credits, might make these technologies commercially feasible years before they would be without such help. In addition, it may be possible to lower cost by constructing

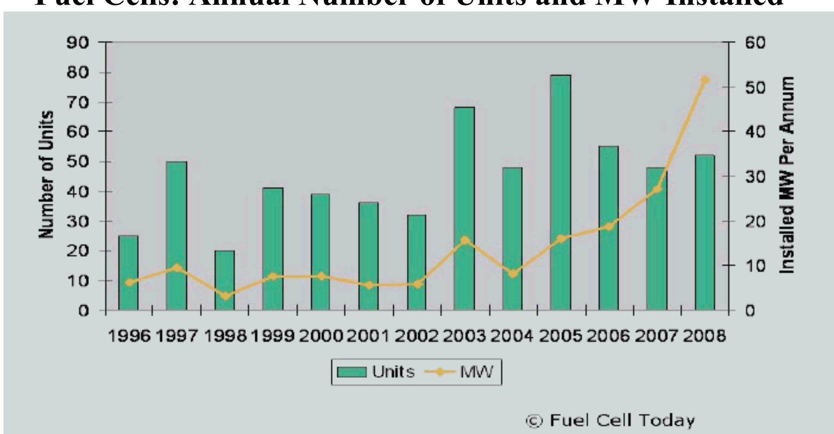
[95] MBMC, SFLAFCO, Report, May 23, 2008.
[96] SFPUC comment document of Feb 11, 2009 states that Local Power does not identify which elements will be available. That is true; it is somewhat difficult to predict what elements of the Smart Grid will be available, and what their characteristics will be, in the first part of the next decade. That is why it is important for the City to follow developments in this market.

infrastructure to a scale available to a CCA, with purchases in the range of 10 to 50 megawatts, when compared to prices for individual projects of one megawatt or less.

There are many green energy technologies today. These are at a wide range of development, from early conceptualization all the way to fully mature products that have global annual production of many gigawatts. According to REN-21's worldwide survey of renewable energy "In 2007, more than $100 billion was invested in renewable energy production assets, manufacturing, research, and development."

Growth of the market for green energy has also been rapid, at rates between 20% and 60% per year. This means that information on the state and availability of technologies is quickly obsolete. For example, installation of new wind power capacity in the US for 2007 was double what it was in 2006, and ten times as large as 2004, a year when federal tax credits were not available. The new wind capacity for 2007 was over 5000 megawatts, which is about 1/3rd of the new electric generation capacity constructed in an average year in the US. Similar growth has been seen for fuel cells and utility scale electric storage batteries. [97]As the chart below shows, installation of stationary fuel cells has soared from 10 MW per year in 2002 to over 50 MW per year in 2008.

Fuel Cells: Annual Number of Units and MW Installed [98]



A number of technologies are rapidly emerging from experimental or prototype stages. This is true of tidal and wave generation, that both saw new technology enter commercial operation in 2008. Thus is it is important to keep an eye on emerging developments, and try to prepare for opportunities that may arise over the next three to ten years, as a CCA develops.

The following sections cover some green technologies that might be implemented by a CCA. This is far from an exhaustive description of what is available, but—in general—takes the approach of choosing a particular product for each type of technology that is

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[97] NGK on July 7, 2008 announced plans to increase annual production capacity from 90 megawatts to 150 megawatts of Sodium Sulfur (NAS) batteries, (announcement in Japanese) http://www.ngk.co.jp/news/2008/0728.html

[98] 2008 Large Stationary Survey, Dr. Kerry Ann Adamson, Fuel Cell Today, August 2008.

furthest along toward market readiness. An alternative approach is to describe characteristics that would be desirable to look for in order to make technology applications viable, such as performance characteristics or financing options.

i. Fuel Cells

Fuel cells are an old technology that has only recently begun to be used for conventional applications. First built in 1839, they were essential many years later in the early space program for providing reliable electricity on the Apollo missions to the moon. Fuel cells generate electric power by consuming fuel using non-combustion, electro-chemical process. The most common fuel is hydrogen, which may be derived from hydrocarbons as well as from electrolysis of water. Modern fuel cells frequently take a feedstock fuel, such as natural gas, and convert that to hydrogen using a reformer module. The reformer strips the hydrogen off the carbon atoms and releases Carbon Dioxide. The hydrogen is then used to power the fuel cell, chemically bonding with oxygen. Fuel cells have very low air pollution emissions, much lower than conventional electric generators using fossil fuels, with the primary exhaust being water vapor. For this reason, they may be acceptable in urban environments where air pollution is a major concern.

Until quite recently, fuel cells have been relatively expensive compared to conventional sources of electric generation. Installed costs ranged from $4000 to $8000 per kilowatt, when conventional power plants—in former decades— have been about $600 to $1200 per kilowatt. Recently, however, the economics of power generation has shifted. New natural gas plants, which define the lower end of the power plant cost scale, have risen from $600 to nearly $900 per kilowatt, while state of the art IGCC coal plants would be about $3000 per kilowatt. New nuclear plants are expected to be even more expensive than IGCC coal. [99], [100]

The cost of fuel cell technology is affected by scale. Most fuel cell projects have been smaller than a megawatt, which increases cost. Fuel cell plants over a megawatt have recently cost about $4700 per kilowatt, and about $100 per kilowatt lower for municipal utilities. [101] If the City purchased in volume, the cost may have the potential to be lower. It is quite possible that installed cost could become competitive with coal or nuclear plants over the implementation period of the San Francisco CCA.

[99] All costs are from COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES, Final Staff Report, California Energy Commission, December 2007, CEC-200-2007-011-SF.

[100] SFPUC comment document of Feb 11, 2009 points to "industry standard cost for conventional resources of approximately $850 per kw." This figure is cited already in our report; however SFPUC staff is incorrect to suggest that this is the general price of conventional power plants. It is only the cost of natural gas baseload plants. Nuclear and coal plants are expected to be much higher in cost. The cost of conventional power plants has been escalating rapidly in the past decade, and it is reasonable to assume that this may continue.

[101] ibid.

On the other hand fuel costs would be significantly higher, if natural gas is used. This would be the case for a Molten Carbonate design, which is the only type of fuel cell produced today in capacities of a megawatt or more. Because Molten Carbonate fuel cells operate at high temperatures, fuel cost can be mitigated by recycling the waste heat in a combined heat and power system. The sites identified by SFDOE as having potential for cogeneration should be evaluated for using fuel cells.

Carbonate fuel cells are manufactured by Fuel Cell Energy in Connecticut, with new cell production at about 30 megawatts per year. [102] The manufacturer says that the current facility is at about half capacity, and can be ramped up to 60 megawatts per year by adding more shifts. If the market continues to grow, they can increase production by expanding the facility. They say that they can supply an order of 50 megawatts over a three year ramp up period.

The recent Economic Stabilization Act includes a 30% tax credit for fuel cells, up to a limit of $3000 per kilowatt. While this might help bring down the cost of electricity from fuel cells, the credit is only available to tax-paying entities. Thus a CCA would not be able to benefit from this credit unless a third party owned the fuel cell system. However, this might increase the financing costs, since private lenders are likely to need higher rates of return than the bond rate available to a CCA. The two ownership models should be compared.

According to the California Energy Commission, the levelized cost of electricity from a molten carbonate fuel cell is 9.77 cents per kilowatt-hour if public financing is used, and 11.78 cents per kilowatt-hour for an investor owned utility. This assumes access to free methane fuel from a waste facility. If the fuel is natural gas, the cost would be significantly higher. LPI estimates this would add 6.8 cents per kilowatt-hour, assuming a natural gas price of $8 per mmbtu, and 40% thermal to electric efficiency. The fuel price could drop to near 4 cents per kilowatt-hour if heat recovery is used, with a total cost of energy from fuel cell plants of 12 to 14 cents per kilowatt-hour for a CCA.

Fuel cells provide on-site base load power, the value of which can be estimated by the CPUC's Market Price Referent (MPR). The MPR for 2014 shows base load natural gas plants under a 20 year contract costing 9.5 cents per kilowatt-hour. If one accounts for transmission losses, transmission and distribution costs, then the on-site fuel cell energy might actually be competitive with conventional base load power. Another option for lowering the cost, and carbon footprint, of fuel might be to use biomethane sources.

ii. Wave Power

Several new technologies are being developed to tap the power of ocean waves. In September, 2008, Portugal started operation of the Aguçadoura project, the world's first wave power farm. This facility uses the Pelamis machine, a 435 foot long segmented

[102] Data on production capacity is based upon phone conversation with plant manager at Fuel Cell Energy.

snake-like device that floats on the surface of the water. The three segments rise and fall with the waves, causing an internal fluid to fall through turbines and generate electricity. Electricity from the units are combined, and then sent through a cable that connects to shore. The first project phase installed three wave energy converters, at a cost of 9 million euros. The second phase will install 25 more machines, each rated at 750 kilowatts, and bring total capacity of the farm to 21 megawatts.

In general, Pelamis wave converters are expected to generate between 25% and 40% of their rated capacity, depending on the local wave resource. In Portugal, according to Pelamis' global resource map, the wave energy at the site is between 39 and 46 kilowatts for each meter of wave front. While the company claims that any site with over 1 5 kilowatts per meter is capable of producing wave energy at competitive prices, this does not appear to be possible at current costs to install the Pelamis machines.

LPI estimates the cost to produce wave power from the first 3 machines is about 40 cents per kilowatt-hour. This assumes that the machines are operable for at least 20 years, financed at an 11% weighted cost of capital, and generate power at 30% of rated capacity. It is expected that phase 2 will be less expensive on a unit basis than phase 1 due to economies from manufacturing and installing on a larger scale.
Determining the feasibility of wave technology requires an evaluation of the site, testing not only for wave power, but also distribution of waves classified by height as well as how long an average wave cycle is. Different technologies will capture different types of wave regime. The wave resource offshore San Francisco, particularly toward the north of the City, has an energy flux of about 30 kilowatts per meter, roughly 3/4ths the resource of the Portugal site, and the total local resource has been estimated at 3147 megawatts. [103]

While the lower resource tends to make wave energy more expensive in California than in Portugal, a CCA can take advantage of lower cost financing. Municipal H-bonds would make the cost of electricity from the Pelamis lower than what it is in Portugal, despite the lower California resource. If zero-interest federal bonds are used for financing the project, then the cost of electricity would drop to about 11 cents per kilowatt-hour, using the same assumptions about scale and capital cost for the San Francisco facility as the phase 2 in Aguçadoura. If the cost of generating base-load power from natural gas increases, as is forecast , the cost of installing wave conversion technology would only have to decrease modestly to be competitive.

A San Francisco CCA would have to deal with several jurisdictions to access offshore sites for energy projects. There would be considerations regarding shipping, fishing and the marine sanctuary, that will pose significant challenges. However, a wave farm has the potential to generate a more stable power than a wind farm, and contribute toward base load energy supply. This gives wave power a specific value. In addition, the wave resource is quite large, much bigger than the tidal resource. Thus wave power has the potential to generate a sizable portion of the CCA's electricity, and a technical potential far beyond San Francisco's needs.

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[103] California Small Hydropower and Ocean Wave Energy Resources, in support of the 2005 Integrated Energy Policy Report, Mike Kane, PIER Renewables Staff, California Energy Commission, May 9, 2005.

iii. Urban Wind

While a small urban wind turbine is much cheaper to purchase than industrial scale wind towers, smaller urban wind facilities are very expensive in terms of the unit cost and cost of energy. Where commercial wind turbines average about $1900 per kilowatt, fully installed, a small rooftop or backyard wind turbine might be as costly as $5000 per kilowatt. Even more problematic, these small turbines are placed at a relatively low height, where winds are usually less intense. And the urban wind regime is generally much less favorable than a commercially viable site. This all adds up to very expensive cost of urban wind electric power.

To make urban wind affordable requires a multi-pronged approach, all of which will need to achieve gains if urban wind is to be economical:

- Realize the premium value of on-site power generation, which on average is double the value of wholesale electric power
- Find optimal sites in the City where wind resources are at least a class 3 or 4
- Allow for increased height; going from 30 feet to 200 feet can increase resource by one wind class in many cases
- Achieving cost reductions by ordering large quantities of small wind turbines, and putting them all on a single operations and maintenance agreement
- Or, alternatively, finding acceptable industrial sites where large commercial scale towers can be located with optimal wind resource and sufficient on-site or over-the-fence power needs

In combination with some or all the above, low cost, or zero cost financing could tip the balance in favor of urban wind power. That is because nearly all the cost of a wind generation system is upfront and thus capitalized with loan or investment money that must bear a rate of return. A typical commercial wind farm might carry an average weighted cost of capital of 11 percent per year. Every nine years the wind farm costs as much in interest and profit as the original cost to build it. Over a 20 year or longer economic lifecycle, the cost of money becomes a dominant factor in the cost of electricity. Lowering or eliminating the cost of money can make many wind projects economical that otherwise would not be.

Adequate wind is also particularly important, with power generation highly sensitive to relatively small differences in average wind speed. Wind power is a function of the cube of the velocity, so a 25% increase in wind speed results in nearly doubling the power.

At present, the issue for urban wind is about meeting the cost, performance and financing criteria rather than lack of available technology. There are a number of manufacturers of small to mid-sized wind turbines with a range of performance characteristics. However, there is currently a lack of mid-sized (50 kilowatt to 250 kilowatt) wind turbines that might fit the urban landscape yet also achieve economy of scale. This might be an opportunity to create a manufacturing facility to supply a potential market niche.

It is also possible that some emerging technologies may improve the cost and performance of urban wind systems. The risk of trying novel technology can be mitigated in several ways:

- Initial trial on a small scale for a few years until performance can be verified
- the CCA can assume some or all of the risk from individual customers deriving energy from the novel technology
- Scaling up gradually to limit the effects of performance shortfall
- Installing systems under a power purchase agreement, so that the burden of performance falls on the entity owning and operating the facilities
- warranty by sound business entities
- collaboration with research by universities, state or federal government agencies, or business firms
- funding from government or private sources

iv. Offshore and Other Alternative Wind

Offshore wind has been developed in Europe, but not yet in the US. There is an effort to secure approval for an offshore wind farm at Cape Cod, Massachusetts that has faced significant local opposition. Offshore wind facilities require excellent wind resources as well as large areas of shallow water, in order to justify the significantly higher cost than onshore wind farms. Offshore wind towers are mounted on firm foundations that must withstand the challenging forces of wind, weather and waves.

Current offshore wind technology is not considered technically feasible for San Francisco. This is because the locations where wind resources would justify the substantial cost are in a depth of water that is greater than current technology allows. However, there are excellent wind resources off the northern California coast.

Placing turbines immediately west of San Francisco might face several extra challenges. This region contains vital shipping lanes as well as fishing and recreational use. There is also a national marine sanctuary, and views from shore with great scenic value. Any offshore wind facilities would need to be accepted by the community in order to be built at all.

For many years, people have proposed to build floating wind farms far out to sea where the best wind resources in the world are found. A number of designs have been considered, including ones that produce hydrogen fuel, a convenient way to store the energy and thus make wind a more reliable power source. Hydrogen could then be sent to shore, either by ship or pipeline. Another key feature of far offshore wind is that visibility is reduced or eliminated as an environmental concern.

There are technology options for deep water offshore wind that may prove feasible over the next decade. One of these, called Hywind, is being developed by StatoilHydro. The Hywind is designed as a floating vertical tower that is tethered using cables to the sea floor. The ballasted float would have a 100 meter (330 foot) draft, and is designed for deployment in water depths of 120 to 700 meters.

The energy company has experience building wind farms as well as offshore oil and gas platforms. They have both the engineering and financial capability to carry out the long term development needed. Between 2003 and 2005, the Norsk Hydro invested 20 million NOK, and StatoilHydro is committing 400 million NOK for future development. The first model floating prototype was tested in a wave simulation tank in a research facility at Trondheim, and the design is projected to require another decade of development to achieve commercialization. They have announced an interest in finding locations around the world to test their technology during the later part of this development phase.

Another group of technologies that may prove viable are airborne wind turbines. These are either lighter than air, such as the Magenn MARS, or they use aerodynamic forces to stay aloft. Magenn's MARS wind power generator uses helium to fill a balloon turbine that is tethered to the ground. Wind is caught in the protruding fabric sheets that spin the turbine on a horizontal axis. This system could be used either onshore or offshore, and the company tested its first large scale prototype in early 2008. Magenn's MARS generator would be unsuitable for most areas in the City; they must be at least five miles from any airport and outside of any flight paths. For safety, they should also be away from any location where falling equipment might injure people.

Skywind Power of San Diego is developing a wind turbine designed to operate at altitudes of 15,000 to 30,000 feet, where winds are much more regular than near ground level. Operational capacities of 50% to 70% are possible, which could make wind a more reliable source of power and reduce the intermittency problem associated with current wind power. The Skywind Power system is just one example of a potential future class of wind turbines that use aerodynamic principles.

Adoption of any novel wind technology would depend in part on cost and performance, but could also be use the same cost and risk mitigation methods described for urban wind. Of course, the new technologies described would also come with some specific challenges associated with permitting, siting and safety. These would have to be adequately addressed prior to implementation.

v. Hot Rock Geothermal

Current technology for generating electricity from the heat inside the earth can only be placed in relatively small areas where high temperature underground steam is located. In California, the best locations are at the Geysers in Sonoma and Lake Counties, as well as near the Salton Sea. Many other places have lower temperature steam, but most of these are unsuitable for producing electricity. San Francisco is not known to have geothermal resources that could use conventional technology.

A large area of the state—including San Francisco— has very hot rock at depths of 30,000 feet or more, with temperatures in excess of 400 degrees F. Tapping this resource depends on new methods that can use this large resource, with technology that is being developed. Australian company Geodynamics drilled 6 to 8 inch diameter wells for "proof of concept" to over 4000 meters depth, called the Habenero Project, in northeastern South Australia.

To be economically viable for electric generation, cost and performance would need to match similar projects using conventional technology. The underlying rock would also have to have a suitable character for exploitation, characteristics that are only beginning to be understood. The risk of minor earthquakes has been a known effect of geothermal development,[104] though geothermal areas can be subject to earthquakes even without energy development. The maximum size of observed earthquake from hot rock, deep wells was a magnitude 3.4 in Switzerland.[105] According to the US Geological Survey, there are about 130,000 earthquakes per year in this range, and they pose little hazard.[106] Much more dangerous earthquakes have been known to be caused by coal mining, the primary source of energy that geothermal would replace in the US.[107] The most powerful earthquakes caused by human activity have been due to natural gas drilling in Uzbekistan, ranging as high as magnitude 6.8 to 7.3. These were roughly equivalent to

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[104] SFPUC staff expressed concern about earthquakes associated with geothermal development, feeling that Local Power had neglected an important technical risk, so we have added a brief discussion of this topic.
[105] Geothermal Power Plant Triggers Earthquake in Switzerland, by Christine Lepisto, Berlin on 01.21.07, http://www.treehugger.com/files/2007/01/geothermal_powe.php

[106] http://neic.usgs.gov/neis/eqlists/eqstats.html
[107] *Coal Mining Causing Earthquakes, Study Says*, Richard A. Lovett for National Geographic News, January 3, 2007. An earthquake of magnitude 5.6 was caused by coal mining in Australia, killing 13 people, injuring 160 and causing $3.5 billion worth of damage.

the Loma Prieta quake, and the largest of these released energy roughly 700,000 times the largest geothermal well incident.

One potential benefit of a geothermal electric generation project in or near a city would be using excess heat for commercial purposes, such as heating water or interior spaces. This might improve the economics of hot rock geothermal power.

vi. Battery Storage

TEPCO, the Tokyo Electric Power Company, with NGK, produces sodium sulfur (NAS) batteries, the only batteries in the world manufactured for utility scale energy storage. These batteries have been built in sets that can produce 9.8 megawatts of power for a period of up to 6 hours. There are a number of important characteristics of the NAS battery. The materials are relatively non-toxic compared to the heavy metals used in most other batteries. These materials are also abundant and inexpensive. The batteries can be charged and discharged up to 100% with a high degree of efficiency. This allows them to supply grid power during hours of peak demand, with the potential to provide insurance to the ISO for high grid reliability. The batteries are expected to be able to last for 15 years with modest degradation of efficiency over time.

These batteries have been manufactured for years, and TEPCO has rapidly scaled up production to where 90 megawatts per year of NAS batteries are being produced. The company is looking at further expansion. At megawatt scale, cost of a battery storage system is about $2000 per kilowatt, [108] with potential for further cost reductions.

Batteries would store power at night when demand is low and power sources are relatively cheap, and then release the power during the day when needed. Power during the day is much more valuable, which can make up for the incremental cost of the battery. In addition, batteries can be used in conjunction with intermittent renewable energy to supply reliable power. They can also be used at sites that demand high quality power and cannot sustain power losses without losing substantial revenues or creating significant risks. This may include data processing centers, banks, or public safety facilities. A single battery could back up and be operationally coordinated with a large number of renewable and demand resources. In this way, batteries would be an important part of a local renewable energy system.

[108] A 1.2 megawatt NAS battery in West Virginia was reported to have cost $2.5 million, or just over $2000 per kilowatt. New Battery Packs a Powerful Punch, by Paul Davidson, USA Today, 7/5/2007. http://www.usatoday.com/tech/products/environment/2007-07-04-sodium-battery_N.htm

vii. Smart Grid

A variety of technologies would combine to form a smart grid, including communication and monitoring equipment with real time controls. The concept of the smart grid and its technological development are still at an early stage of development. One of these elements would be "smart meters" that regularly monitor consumer demand at each customer location. Smart meters are scheduled for deployment by California investor-owned utilities in the coming years. These meters could have a wide range of possible specifications, and the California Energy Commission staff has stated that they are committed to making sure the correct technology is implemented to meet projected future energy system needs.

The CPUC has already authorized budgets, and technology choices have been made for the Smart Meter program. PG&E customer rate increases of $1.7 billion have been approved to cover installation of 5.4 million electric and 4.7 natural gas smart meters. This comes to an average allocation of $138 per installed meter without the information technology costs, and $168 per meter if these costs are included.

PG&E has recently asked for a rate increase to cover an additional $572 million for the smart meter program. This would raise the total program budget to $2.3 billion. PG&E claims that software development will cost $638 million, up from the initial $275 million allocated originally for information technology.

Meters will be able to communicate wirelessly with nearby central data collection nodes that will connect to the internet and allow remote monitoring and control of each utility customer energy usage. New generation "smart appliances", such as thermostats controlling air conditioners, could be adjusted to reduce energy consumption during periods of peak demand. According to the CPUC, PG&E projects that they will be able to reduce peak demand by 448 megawatts using the Advanced Metering Infrastructure.

Objections have been raised by San Francisco, consumer advocates and DRA to having customers assume the extra cost burden for smart meters. Other consumer advocates have named some specific problems with smart meter systems. These focus around the value of net benefits over the cost, with emphasis on rate structure and whether low income customers get any benefit. There are minimal energy savings expected from simply installing smart meters. The utility can monitor customer demand in near real time and adjust the purchase of extra power to meet rapid changes in demand. On the other hand, there may be service benefits from being able to detect and respond more quickly to outages or other distribution problems.

Energy savings would result from allowing customers to get feedback regarding their electricity usage, and installing controls that allow them to modify their demand. Tests of such systems show significant reduction in energy use, particularly for customers who have larger energy consumption and higher bills. Peak demand reduction is maximized by implementing what is called Critical Peak Pricing, a scheme that exposes customers to changing prices of electricity over the course of the day. Again, the benefits are greatest for customers with higher energy usage, and there are questions whether low income customers would see any significant savings on their own bills after accounting for the cost of the meters.

These commitments are being put into place prior to the implementation of a San Francisco CCA, and so far without consideration of specific CCA needs. However, the smart grid network envisioned for San Francisco would benefit from real time data acquisition, and the ability to adjust demand and power storage systems to balance intermittent renewable electric generation. LPI recommends further investigation into ways that a CCA can mitigate or reduce burdens upon low income customers from smart grid implementation, either through using its rate setting authority or through targeted implementation of energy efficiency or other green energy programs that might benefit this group of customers.

In addition to smart meters, solar companies have installed real time monitoring for production of photovoltaic power. This can be hooked up to the internet and viewed in real time from any computer. An example of this type of product is manufactured by Fat Spaniel. All networked green energy elements in a CCA will need to be monitored and coordinated with smart grid technology to maximize efficiency and minimize power supply cost and waste.

Another potential element of a smart grid is the "microgrid". These are very localized, potentially a neighborhood or a few larger businesses sharing a common distribution system, that coordinate demand and local energy production. The real time monitoring the local energy usage and production, along with power storage and use of controls, can provide increased stability, energy security and self reliance. Microgrids can provide similar benefits to the larger grid as a whole if the systems are designed properly. Particular attention has to be paid to technical issues of grid operation, including safety during outages, reliably meeting demand, reactive loads, power quality, and stability of the 60 hertz frequency of the alternating current.

Most importantly, if technical hurdles can be overcome, a San Francisco CCA can benefit from smart grid technology, through:

- allowing higher penetration of intermittent renewables
- integrating operation of distributed power sources
- design of improved demand reduction, efficiency and green technology programs
- providing higher reliability and power quality to customers
- assist in integrating future network elements, such as plug-in electric cars

Smart grid is a valuable tool for helping meet the City's targets for demand reduction, renewable power and increased energy independence.

b. Needed Financial and Knowledge Resources for Smart Grid and Emerging Technologies

The City should pursue available support to help it develop and build advanced green energy technologies. This effort should include obtaining both technical and financial assistance, as well as partnerships with local utility customers, government agencies, universities, businesses, and financial institutions. Coordination with PG&E and utility regulators will also be important.

If the City or CCA waits until opportunities for research or funding emerge, it will likely be too late to take effective advantage of these opportunities. San Francisco should move forward the planning processes for green energy options, even those that are currently expensive or novel, to be ready for future opportunities that may arise.

Local Power recommends focus on the following areas:

1. Research. Efforts to push the boundaries of technology can benefit from partnership with entities that conduct research, such as the University of California, the various laboratories operated under the authority of the Department of Energy (NREL, INL, LBNL, LLNL, Los Alamos, etc.), as well as non-governmental research organizations (EPRI, RMI, etc.). Some commercial entities also conduct research and programs for green energy. Local examples include Google and the PARC laboratory. These would be natural entities for a San Francisco CCA to partner with.

Generators installed for research purposes could operate symbiotically with a CCA. Any such arrangement would need to be cost effective for the CCA. The CCA has a number of potential tools to assist in accomplishing this, including access to grants, low cost financing and contracting to purchase power at an agreed price that is reasonable. Cost considerations would likely limit the number and size of such projects. However, individual research projects are likely to be small, and this would tend to minimize the effect on customer rates.

The potential long-term benefits to a CCA could be significant if breakthroughs are accomplished in innovative technologies, and these become marketable.

2. Demonstration Sites. A San Francisco CCA can gain priority as a demonstration site for new technology. It has several benefits to offer:

- low cost H-bond financing authority
- the ability to make commitments to purchase energy from the facility
- the ability to simplify regulatory processes and permitting
- its high reputation for and commitment to green energy development
- its effort to pioneer a green energy network

In particular, the ability to purchase power from the facility can complement the other funding sources to make a project viable. There are possibilities for future development of offshore wind, wave, tidal, smart grid and other technologies. Some of these, such as offshore wind and wave farms, might benefit from partnership with Marin or Sonoma CCAs. There are higher wind and wave resources offshore from these counties to the north, and larger scale development might be able to lower costs as well as distribute development risks.

iii. Grants & Rebates

Funding for research or innovative energy projects is available through the California Energy Commission and the US Department of Energy. Venture capital startups may also have research budgets. Partnership with non-profit organizations may be able to draw funding from foundations devoted to advancing green energy. The California Energy Commission offers rebates for renewable energy technology, such as small wind turbines and fuel cells that operate on renewable fuels. Federal grants or rebates are sometimes also offered for limited periods of time. The emerging focus on green energy, green jobs and climate protection may open up new funding options in the next few years.

iv. Zero Interest Federal Bonds

The 2005 National Energy Policy Act allowed local governments to apply for portions of an $800 million allocation of zero interest bonds to build renewable energy facilities. The bonds give investors a federal tax credit in lieu of interest payments, and were allocated in a matter of months. As such bonds become authorized again, the City should seek to apply for them. By eliminating interest payments, the bonds reduce the cost of energy from renewable projects, since the cost of borrowed money and profit is often much greater than the original cost of the renewable facility. This could turn renewables that would otherwise be too expensive into justifiable sources of energy for the CCA.

v. Tax credits

City governments and CCAs are not tax-paying entities. As such they cannot directly take advantage of tax credits offered for green energy. Currently, there are tax credits that pay for 30% of the installed cost of solar energy and fuel cell projects. Partnership or contracts with third party owners and commercial sources of financing may allow the CCA and its customers to benefit from tax credits. Such arrangements must follow federal tax code and IRS rules, but the City should explore ownership options to gain these benefits where appropriate.

There is also a 2 cent per kilowatt-hour production tax credit for some types of renewable electric generation, including wind and geothermal. This tax credit is unavailable to government entities, although in the past the federal government has authorized a payment for public power agencies that is equivalent to the tax credit.
However, the program has rarely been funded.

In general, H-bond financing through non-profit ownership by a CCA will exceed the benefits from the production tax credit. This is particularly due to the fact that the credit is only paid on the first ten years of energy production, while bond financing will lower cost for the full financial lifecycle, which can be 15 years or longer.

It is important to evaluate each project to compare relative benefits of financing options versus available tax credits.

9. Best Practices Survey of Green Portfolio Programs

The DSIRE database, which is an inventory of green energy incentives in the United States, lists 160 different programs in California for solar energy, renewables, energy efficiency and green building. The wide variety of programs that support the growth of green energy fall into several broad categories:

- *monetary incentives* such as rebates, tax credits, and performance-based incentives.
- *renewable purchasing programs* where utilities are obliged to buy renewable energy directly, such as the Renewable Portfolio Standard, Net Metering and Feed-in Tariffs.
- *subscription programs* that are paid for by customers, usually at a premium over regular utility rates, such as purchases of "green tags" and enrollment in green energy portfolios.
- *financing programs*, such as voluntary property tax assessments and low interest bonds.
- *creative ownership models*, such as third party ownership and community ownership shares.

This Best Practices Survey examines a small sample of effective green programs that have been selected because they could be implemented in San Francisco in conjunction with a CCA: rebates, green portfolios, local green-tag purchases, feed-in tariffs and community-owned projects.

Rebates for solar energy are considered first for several reasons. The rebate programs in California have unquestionably been the most successful solar programs in the nation, and are responsible for building up most of the photovoltaic generation in the US. The state's rebates have also been relatively well funded. In this sense, solar rebates represent a kind of benchmark for "best practices", as well as a common element of all utility solar programs in California. Solar rebates are also considered due to the recent entry of San Francisco into offering its own rebates. It is important for the City to understand the character and market effects of rebates, as well as the design options and possible improvements upon the generic rebate structure.

There are significant benefits that can be realized by integrating these rebates with other best practices that are currently up and running in other cities, such as community ownership shares in a solar project and community purchases of green credits. The City's control over its own rebate program would be particularly important, since some of the most creative ideas are currently excluded from participation in the California Solar Initiative (CSI), and rebates from CSI are on the verge of falling to levels where they will not be sufficient to maintain the solar market. In the face of such challenges, a

Community Choice Program would be well situated to combine the best practices to allow every San Franciscan to have access to affordable solar power.

Solar Rebate or "Incentive" Programs

All municipal and investor-owned electric utilities in California are required by state law to offer rebates for solar energy systems until 2017. Some local governments, such as San Francisco and Marin County, are offering additional solar incentive payments on top of the state program even though they are not required to do so. Municipal utilities are less closely regulated under state law, and some of these offer rebates that are higher than what the investor-owned utilities give their customers. For example, Los Angeles Department of Water and Power (LADWP) pays out a generous rebate that is worth about $4.50 per watt, and that varies according to the performance of the solar energy system. By comparison, Southern California Edison, the investor-owned utility that serves customers outside Los Angeles, pays $2.20 per watt.

For a rebate program to work, it is necessary that the payment rates be set high enough to stimulate the market. The state rebates, offered through the investor-owned utilities, initially were quite low—only paying for about 1/4th of the installed cost of solar electric generators. Due to the low response by customers, these were increased in the early 2000s to $4.50 per watt, or about ½ the installed cost. At this point demand increased dramatically, and this demand remained strong even as the rebate levels were gradually reduced over the next several years.

Rebates are decreased over time on the theory that they are temporary assistance that is supposed to help reduce the cost of solar energy by building a self-sufficient market. The subsidy pays the difference between the market price for solar and utility rates. However, if the rebates go down faster than the convergence of these two price trends, then the market can be lost.

Between 2007 and 2017, the California Solar Initiative governs rebate levels for customers of the three big investor-owned utilities: PG&E, SCE and SDG&E. The payment rates are set according to a tiered schedule. (Attachment D) A fixed number of megawatts can be subscribed under each stepped rate, and once that step is fully subscribed for each utility's allocation, than the rebate goes down to the next tiered level. Initially, rebates were $2.50 per watt, but today most customers get either $1.90 or $1.55 per watt. Solar photovoltaic systems cost, on average, between $8 and $9 per watt, so at this point the rebate covers about 20% of the initial cost.

The rebates are clearly effective at stimulating demand, and in this sense may be considered a "best practice". However, the payments are supplemented by federal tax benefits that allow commercial customers or 3rd party investors to take a 30% tax credit as well as 5-year accelerated depreciation. Underscoring the value of the tax credits is the fact that the CSI program pays higher rebates to non-profit entities that do not qualify for the federal tax incentive. At the lower payment tiers, these rebates are two to three times higher than what most residential or commercial customers receive. In addition, commercial deals usually require relatively low-cost financing as well as the ability to sell the "green tags" that represent the renewable value of the solar generators—abstracted from the actual electricity. The current rebates depend on other financial supports, and are probably not sufficient by themselves to maintain the current level of market demand in California.

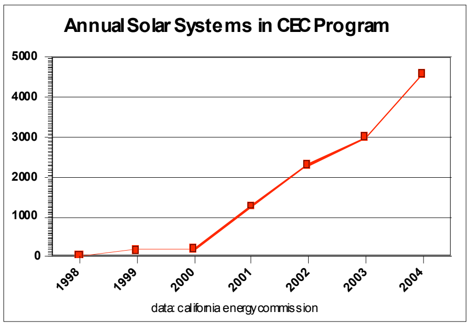
By 2010 the CSI rebate rates, administered through the utility companies, are certain to be lower than they are today. This means that the stimulus value will be greatly reduced, especially when the rebate for most customers falls to $0.65 per watt and lower. At the seventh tier, a $25,000 home system of 3 kilowatts will be subsidized by a rebate of $1950. Considering that high upfront cost is the principle market barrier for solar energy, it is likely that rebates this low will be ineffective unless matched by supplemental assistance. The lower future rebates under CSI are a significant impediment to achieving the 3,000 megawatt statewide target of installed photovoltaics by 2017, and the utility companies include planning scenarios which assume a shortfall.

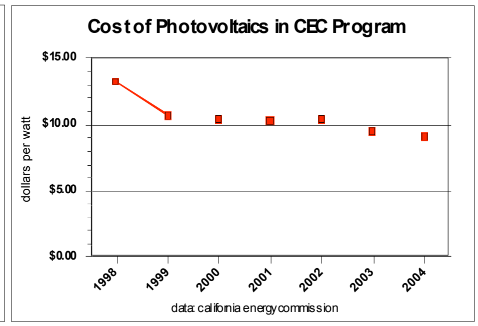
Without intervention, either by reduced market prices or by improved public support, the CSI program is likely to stall somewhere between the 5th and 7th tier. This will leave about 1000 megawatts remaining to be built out of the utility total of 1850 megawatts. A local rebate, or other local program to lower installed costs, could help to keep the CSI rebate program effective.

While rebates are successful in stimulating demand, if set high enough, this policy tool can have a significant, unintended cost: installers may charge more for the photovoltaic systems. This effect was discovered several years ago due to a quirk in the state's rebate programs, which were divided between two agencies that each paid different rebate amounts. The California Energy Commission gave rebates for photovoltaic systems less than 30 kilowatts, at $3.50 per watt, while the CPUC gave rebates of $4.50 per watt for systems over 30 kilowatts. It was found that photovoltaic systems funded by the CPUC in the 30 to 50 kilowatt range were actually more expensive than the CEC funded systems that were just under 30 kilowatts by about 60 cents per installed watt, on average. This was especially peculiar due to fact that larger systems within each program range were generally cheaper, with the exception of this reversal in the price curve at just above 30 kilowatts.

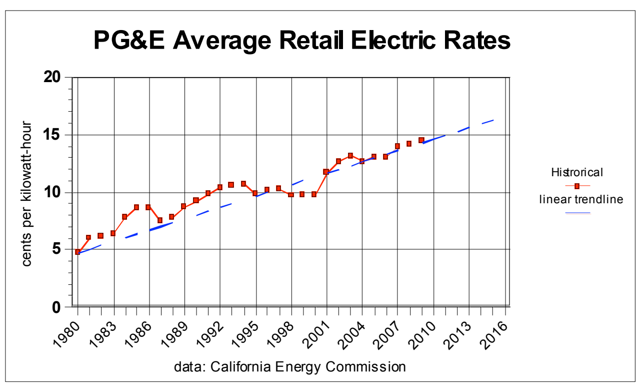
The data suggest that 60% of the rebate value is being transferred to installers and manufacturers. Despite the fact that the consumer has to share the rebate with the industry, the overall benefits of the rebate policy have been significant. The primary purpose of the solar rebate programs is to stimulate demand for a socially beneficial product, and this has certainly happened. Prior to 1998, when rebate programs started in California, there were less than 300 photovoltaic systems in the entire state. By 2007, a decade later, the state's rebate programs had swelled this number to over 30,000. Customers appear quite ready to purchase photovoltaic systems even when most of the immediate value of the rebate is obtained by the installer.

The largest benefit to consumers from rebates is due to the fact that prices have come down over time. This is a direct result of reduced manufacturing and installation costs facilitated by increased demand. Rebates increased demand for photovoltaics in California by a factor of 100 between 1998 and 2004, even as the price dropped by 31%. The price decrease was worth $4.16 per watt, an amount that exceeded the average rebate of $3.91 per watt during the period. In fact, the benefit is greater than this suggests, since the number of consumers benefitting from the lower cost is much larger than the number who purchased at the higher cost. This implies that the rebate policy was an excellent investment for consumers.





When rebates of $4.50 per watt were required to stimulate demand, there were few alternatives that could have created similar results. However, since 1998, the market has been significantly transformed. Solar energy systems have fallen in price by more than the value of the rebates, and electricity prices have increased. PG&E rates have risen by about 40% between 1998 and 2008 to an average near 14 cents per kilowatt-hour.



With new rebates of only $1.55 to $1.90 per watt successfully stimulating demand, other techniques may now be used to market that have equal or greater power than rebates. These techniques could save money while achieving the same benefits that rebates have delivered up to now at a cost of hundreds of millions of dollars per year.

This high cost imposes significant limitations on the scale of a solar rebate program, since there are practical constraints on what ratepayers would be willing to pay for. A statewide investment of $3 billion over 10 years, or about $300 million per year, is expected to subsidize installation of 3000 megawatts of photovoltaics. This program will produce just over 1% of the electricity consumed in the state. [109] While solar subsidies are helpful and important, they need to be supplemented with other measures in order to provide meaningful benefits over the next decade.

Sacramento Municipal Utility District (SMUD) Solar Programs

Sacramento's customer-owned utility, SMUD, has used a variety of programs to promote solar energy. These have widely been seen as among the most innovative in the world, and have gone through several different stages. In the 1980s, SMUD decided to build large-scale solar photovoltaic systems on the site of its nuclear power plant, at Rancho Seco. These were installed initially in one megawatt increments, with joint funding in the form of grants from the US government. SMUD agreed to contribute an amount that approximated what it would cost to get power from other, more conventional sources, with the government paying the "excess" cost. Funding was arranged for the first couple megawatts, with SMUD willing to scale up further if the federal government kept paying its share. It was believed that the cost of photovoltaics would drop over time, especially as the project got built to a larger scale and production of solar modules continued to increase. However, the federal government discontinued funding after the initial two megawatts were built, and SMUD waited for years to add more capacity.

In the 1990s, SMUD evolved a new concept for building solar power. This was to focus not on central power plants, which required a lot of money, but on small systems on customer rooftops that would be distributed throughout the service region. The SMUD solar "Pioneer" program was a joint venture, with the utility and the customer each contributing half the cost. In 1997 it was reported that SMUD became the leading buyer of photovoltaics in the world, [110] and up to that time SMUD accounted for over 2/3rds of the installed photovoltaic capacity in the state.

The California Solar Initiative requires that SMUD install 125 megawatts of photovoltaics in its service territory by 2017. The relative freedom of the self-governed municipal utility to design its own program, a freedom not available to the highly regulated investor-owned utilities, has allowed SMUD to create its own innovative programs.

<u>Solar Rebates.</u> One of the benefits that SMUD customers have received from their measure of independence from the state regulatory system is higher solar rebates. Sacramento Municipal Utility District gives homeowners a rebate of $2.50 per watt, while PG&E customers in the surrounding area only get $1.90 per watt. Businesses in

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[109] The California Energy Commission in California Energy Demand 2006-2016, Staff Energy Demand Forecast, Revised September 2005, estimates that statewide electricity consumption will be between 310,716 gwh and 323,372 gwh in 2016. Average output rate of measured solar energy systems in the state's rebate programs is about 1200 kwh/kw-yr. 3 million kilowatts of solar capacity would thus generate about 3600 gigawatt-hours per year or 1.16% of the state's electricity.

[110] Here Comes the Sun, by David Morris, November 18, 1997 - published in St. Paul Pioneer Press, http://www.ilsr.org/columns/1997/111897.html .

SMUD's territory can get rebates of $1.90 per watt, which is higher than the $1.55 per watt paid to PG&E's commercial customers.

SMUD commercial customers can opt for performance-based incentives (PBIs) that are paid out over time according to the electricity generated by the photovoltaic system. The PBI can either be paid out at 30 cents per kilowatt-hour for five years or 18 cents per kilowatt-hour for ten years. The PBI is completely optional, and commercial customers purchasing photovoltaic systems up to one megawatt are free to choose the upfront rebate if they prefer. This makes the SMUD performance incentives different than the state program offered through the investor-owned utilities, which requires PBIs for all systems over 50 kilowatts [111], and which only has one fixed payment term of five years.

Some redesign of the solar rebate program has occurred in response to the perceived inequity that occurs when customers are paying for a program that delivers most of the rebate to the industry rather than to the customers. SMUD has required that all contractors be approved by the utility before they can install any system that gets a rebate. They also require that "the incentive…should be reflected in the contractor's bid to the customer." [112] In addition, programs are increasingly tying the rebate to the performance of the photovoltaic system, which helps assure that customers get full value from their investment. SMUD's rebate is paid upfront, but adjusted according to expected performance that can be calculated by measuring the orientation of the panels relative to the sun, the efficiency of components, and the access to unobstructed sky at the installation site.

SMUD SolarSmart Homes. This program promotes solar energy in the new homes market. According to John DiStasio, SMUD's current General Manager and CEO, the utility has signed "agreements with 10 homebuilders to build over 4000 SolarSmart homes in the SMUD service territory, which incorporates all of Sacramento County and a portion of a neighboring county. SolarSmart is a SMUD brand that combines solar power and super energy-efficient features in residential housing." [113] SMUD will provide rebates of $5000 to $8000 for each home for improvements that will save up to 60% of the customers electric bill. The 4000 homes represent 30% of the new home market in the region.

SMUD SolarShares. With the SolarShares program SMUD builds a large scale solar facility and sells affordable "shares" of this facility to customers at a fixed monthly fee. The customer's bill is credited according to the output of their share of the solar system over the course of the year, just as if it were located on the customer's own roof. There are many advantages over a solar energy system on a customer's roof:

- the solar facility can be located at a site with optimal access to sunlight

[111] All systems larger than 30 kilowatts will be required to use the performance-based incentive after January 1, 2010.
[112] http://www.smud.org/en/community-environment/solar/Pages/index.aspx

[113] *SMUD finds new ways to deploy solar power*, by John DiStacio, Bulletin (Northwest Public Power Association), Saturday, March 1, 2008.

- the panels can be mounted on structures that track the sun over the course of the day, increasing electric generation and availability throughout the day
- a central facility can be supervised by the utility company or a contractor to assure optimal functioning and proper servicing
- the customer avoids the high upfront cost of a solar system
- customers who live in apartment buildings and condominiums can have solar shares without having to deal with landlords or other tenants
- the solar shares are "portable" in that they can be moved to any location within the SMUD district, while moving a photovoltaic system mounted on your roof would be difficult and costly
- due to economies of scale and tax credits not available to homeowners, the monthly payments are much lower than what it would cost if the customer put solar on their own roof
- The utility does not have to worry about loss of thousands of dollars in rebate investment if the house sells and the new customer takes down the solar system

The economics of this system work best for an entity that can take the federal tax benefits, which are unavailable to SMUD. Therefore, SMUD contracts with a 3rd party to build and own the photovoltaic project. The pilot project is for one megawatt and was fully subscribed in the first few months, and the utility is already considering the possibility of more solar projects, potentially in other areas around the service territory.

Customers pay for shares based on the capacity of the system with the minimum share being ½ kilowatt, costing $10.75 per month. Despite the higher cost of solar energy, the range of available share sizes makes it affordable to nearly everyone, especially when part of that is returned every month to the customer's bill as a credit—estimated by SMUD at about $4 per month for the ½ kilowatt share. Since the cost of the share is fixed, while utility bills usually increase over time, the credit for the electricity generated by the solar share will likely also increase over the 30 year expected life of the photovoltaic system. This should significantly improve the economics of investing in solar shares.

LPI recommended this idea of solar shares to SMUD in a 2005 report when it was hired as a consultant for their solar program. The idea was based upon an unusual solar project, at that time still in the planning stages.

Community Solar

The first program in the US to sell shares in a community solar project was developed in Ellensburg, a small city in central Washington. The 36 kilowatt photovoltaic system was built in November 2006 on open land at a freeway interchange, a location deliberately chosen for its high public visibility. City residents can purchase shares in the project and receive credit every three months on their electric bill for their share of the energy produced. This is possible because Ellensburg has its own municipal utility and thus controls the rates and billing structure.

The city is willing to add to the project with a minimum of 12 kilowatt increments if more people want to participate in the program. Interest has been so strong that two new expansions are planned, the first for 20 kilowatts, and the second for another 50 kilowatts. The small utility, which serves 9000 electric customers, has received inquiries from all over the region, and even other parts of the country. Similar projects are beginning to crop up in other locations, such as Bainbridge Island and Ashland, Oregon. The Ashland municipal program will involve construction of a 63.5 kilowatt community solar electric system, built on top of the city service center "which has excellent solar access." [114]

Gary Nystedt, an employee in Ellenburg's utility, originally dreamed up the idea after considering a list of reasons why people avoid buying solar. The list included about nine factors, including the high upfront cost, people not having roofs facing south, and homeowners who thought that solar panels would be unsightly. Mr. Nystedt thought about ways to overcome all these barriers, and came up with the idea of having the utility build its own solar system and allowing people to invest in shares. He says that the idea has sometimes been met with skepticism due to its sheer simplicity, but the program does have some important nuances. The actual ownership of the photovoltaic system is held by the city, with shares actually only constituting a claim on production of electricity. Mr. Nystedt stresses that this ownership arrangement is necessitated by the conditions for insurance.

The Ellensburg Community Solar Project has a few significant differences from the SMUD SolarShares program. Perhaps the most important is that customers do not pay a monthly fee, but purchase their entire share upfront. Shares in the Ellensburg project also are not sold by fixed capacity units, but by a financial contribution of any amount over the minimum investment of $250. This is the amount required to cover at least the administrative cost of the program. Customers are assured their share of solar energy for

[114] http://www.ashland.or.us/Page.asp?NavID=10994

20 years, after which the city council can decide whether to continue the program. Currently, there are 75 contributors.

The Bonneville Environmental Foundation maintains a webpage for the project [115], where people can immediately view the current energy output in kilowatts, as well as historical electric generation for the day, the week, the month, the year and the lifetime of the project. Other details shown include the temperature of the air and the solar cells as well as the amount of greenhouse gases avoided.

Project partners include: City of Ellensburg, Ellensburg's Utility Customers, Northwest Solar Center, Bonneville Power Administration, Kittitas County PUD, Central Washington University, Nexgen Energy Systems, and Fair Point Communications.

SMUD's Greenergy and PaloAltoGreen

A number of utilities have adopted green energy portfolio programs that customers "opt – in" to by paying a monthly premium on their bill. Usually the amount is quite modest, with options for allowing the customer to obtain half or all of their electricity from renewable sources. Two of the leading programs in the country are in California. SMUD claims to have the fifth largest green energy program in the country with over 30,000 customers participating. This amounts to about 6% of utility's owner-customers. The program only enrolled 1.4% of its customers three years after its creation, and established a goal of 7% participation in 2000. Over the past decade much progress has been made, but the 7% target has still not been met. Considerable effort has been made to promote the program through advertisement and partnering with businesses who have given discounts to customers who enroll in the Greenergy Program.

Residential customers pay an extra $6 per month on their electric bill to get what the utility designates as 100% green power, with 78% coming from wind power. Another 21% comes from methane gas from a local landfill.[116] For those customers who find an extra $6 per month too much to pay, SMUD offers a 50% renewable option for a $3 monthly surcharge. Commercial customers pay an extra 1 cent per kilowatt-hour, which amounts to $20 per month for 2000 kilowatt-hours of green energy. Businesses get decals to put on their windows as well as listing on SMUDs website and other promotional materials. Currently, over 1000 businesses are enrolled in the Greenergy program.

SMUD is committed to meeting the state's target of 20% renewable energy by 2010, even though it is not required by law to do so. They add the Greenergy program projected contribution as extra to the 20% target, thus making the total SMUD commitment add up to 23% renewables by the target date. Thus, the Greenergy program is designed to help SMUD exceed the renewable levels required of the investor-owned utilities. The 3%

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[115] http://www.b-e-f.org/renewables/ellensburg.shtm

[116] The Greenergy Program gets its biomass supply from the 8.3 megawatt Kiefer Landfill in southeast Sacramento County. According to a US Department of Energy website reporting in 1998, "SMUD will pay 2.9¢/kWh for the power, which is estimated to cost 3.5¢/kWh to produce; the county hopes to make up the rest from federal subsidies. In turn, SMUD will sell the power to its 6,300 Greenergy customers, who pay an extra 1¢/kWh on their electric bills for 100% green power." http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=2&companyid=229

contribution to the utility's electric supply is significantly larger than the roughly 1% of energy that is the goal of the California Solar Initiative, over a ten year development period.

SMUD's Regular and Greenergy Power Content Label

POWER CONTENT LABEL					PRODUCT CONTENT LABEL (projected in May 2008)			
ENERGY RESOURCES	2008 SMUD Power Mix* (projected)		2007 CA Power Mix** (actual)		Greenergy® 100% Option and Block Option*		Greenergy® 50% Option	
Eligible Renewable	22%		10%		100%**		50%**	
> Biomass & waste		9%		<1%		21%		11%
> Geothermal		4%		2%		0%		0%
> Small Hydroelectric		2%		6%		1%		0%
> Solar		<1%		<1%		<1%		0%
> Wind		7%		2%		78%		39%
Coal	0%		32%		0%		1%	
Large Hydroelectric	19%		24%		0%		12%	
Natural Gas	59%		31%		0%		37%	
Nuclear	0%		3%		0%		0%	
Other	0%		0%		0%		0%	
TOTAL	100%		100%		100%		100%	

* 100% of **SMUD's 2008 POWER MIX** is from SMUD-owned resources or specifically purchased from individual suppliers.

** Percentages are estimated annually by the California Energy Commission based on electricity sold to California consumers during the previous year.

For specific information about this electricity product, contact SMUD. For general information about the Power Content Label, contact the California Energy Commissionat **1-800-555-7794** or *www.energy.ca.gov/consumer/power_content_label.html.*

* The Block Option is sold in blocks of 1,000 kilowatt-hours (kWh).
** Greenergy® generatore are located as follows: 21% Biomass CA, 1% Hydro & <1% PV CA, 78% Wind CA, OR, and WY.

New Renewables comes from generation facilities that first began commercial operation on or after 1/1/97. The average home in the United States uses 900 kWh per month. (Source: U.S. EPA). Average residential home in SMUD Service Territory uses 750 kWh per month. For information regarding Greenergy®, contact SMUD at **1-888-742-SMUD**, or on line at www.smud.org.

Greenergy meets the minimum environmental and consumer protection standards set forth by the Center for Resource Solutions (CRS) through its Green-e program. For information on Green-e certification standards, call **1-888-63-GREEN**, or visit *www.green-e.org*.

Green-e Energy CERTIFIED

In 2008, SMUD exceeded the state mandated levels of renewable energy of 20%, and accomplished this two years prior to the 2010 target date. Programs like Greenergy make SMUD's renewable portfolio more robust.

The small municipal utility in Palo Alto has a voluntary green program of its own, called PaloAltoGreen. (Attachment E) Charges for both businesses and residences are set at a fixed rate of 1.5 cents per kilowatt-hour of renewable energy. The city estimates that the average voluntary customer surcharge will be about $9.75 per month. The program gets 100% of its energy from wind and solar. Despite having 50% higher costs for the program than SMUD, Palo Alto has leveraged its smaller size, and stronger community support, to boost customer participation levels to 20%, one of the highest in the nation.

One interesting extension of PaloAltoGreen is its support for local solar energy. The utility buys the "green tags" or RECs from selected solar projects inside of Palo Alto. The special Solar Renewable Energy Credits are referred to as SRECs and a much higher premium is paid for these than for normal RECs. The city council unanimously passed an ordinance[117] in December, 2007 that authorized the city manager to negotiate 20 year purchase contracts for SRECs under an exemption to the normal contract limits of 3 years. Payment rates for claiming the "green rights" are currently 5 cents per kilowatt-hour, but are projected to range between 3 cents and 15 cents per kilowatt-hour. Initial payments will only go to photovoltaic installations larger than 100 kilowatts in order to simplify administration of the program. [118] *Such purchasing of local solar RECs from customers inside the City's jurisdiction is specifically recommended under San*

[117] City Council Resolution 773, 12/3/2007.
[118] DSIRE online database; http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA165F&state=CA&CurrentPageID=1&RE=1&EE=1

Francisco's CCA Draft Implementation Plan approved in July 2007, and the Palo Alto utility is an example of this policy being put into effect.

The experience with SMUD and Palo Alto shows how green energy programs can be larger in scale, with more rapid roll-out, than solar rebate programs have been. Both of these programs are best treated as *supplemental to fundamental programs* that require large portions of utility energy supply to come from renewable energy. Voluntary green programs are useful to give an extra boost to green energy, as well as provide insurance against shortfall in the larger programs.

Other Green Energy Programs

A number of cities are attempting a variety of approaches to promote green energy. Some of these are well proven, while others are in the planning stages, small scale or unproven.

Austin. Austin Energy, the local public utility, is governed by the city council which has adopted a number of clean energy programs. In 2003, the council mandated that the utility must obtain 20% of its energy from renewable sources by 2020, and this requirement is currently being increased to 30%. In addition, they have adopted a goal of 700 megawatts of demand reduction through efficiency and peak load savings, nearly seven times the amount of reduction in the San Francisco Draft CCA Plan.[119] In addition, they are pursuing a target of 100 megawatts of solar energy in the community by offering rebates of $4.50 per watt, with a higher rebate of $5.60 per watt if the equipment is manufactured in Austin. The solar rebate budget has been ramped up from about $900,000 to $3 million per year. Austin Energy serves a population of about 900,000 people, slightly larger than San Francisco, but the annual electricity use of 11,000 gigawatt hours is nearly double what San Franciscans consume. The utility is engaged in soliciting community input regarding its plans for the future. [120]

Municipal Feed-in Tariffs. Gainseville Florida is the first city in the US to offer fixed payments for solar energy production from customer-owned electric generation. Ed Regan of Gainseville Regional Utilities (GRU) brought the idea back from his visit to Germany, where the national government has set up the most successful solar program in the world. Under a feed-in tariff, the utility pays the full cost of all electricity generated by a solar electric system, not just the excess power as in net-metering in effect in many states, including California. A feed-in tariff is usually set quite high, to allow full cost recovery plus a fair profit. In Germany, many people invest personal money in solar systems to get the guaranteed rate of return that they provide. The GRU tariff would be paid at a fixed rate for a period of 20 years.

[119] Austin Energy has a base load of 1000 megawatts and a peak near 2400 megawatts, much higher than the base and peak needs of 600 and 950 megawatts for San Francisco.
[120] http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf

The feed-in tariff would replace a current up-front rebate of $1.50 per watt that the utility pays. The city imposes a maximum cash value of $7500 for residential customers and $35,000 for businesses. This limit creates a significant problem in that it rewards smaller systems and punishes solar projects that are have better cost effectiveness due to economy of scale and better access to sun.

Feed-in tariffs spread out payments over time, and thus can help utilities afford the programs. In Germany the program costs only about 1% of the utility bill, and GRU estimates that annual costs would reach a similar level of 1% rate impact by 2029, assuming that one megawatt per year is installed, for a total of 20 megawatts.

Once a CCA is established, the current rebate system in San Francisco could—at the option of the City— be converted to a feed-in tariff to take advantage of its several benefits. This is possible due to the fact that CCAs can purchase power directly from a seller, including its own customers.

Voluntary Property Tax Assessment. The City of Berkeley is planning to promote solar energy using voluntary tax assessments on customers who want to purchase photovoltaics but need help with financing. Some tax advantages may accrue; assuming that a tax deduction is can be arranged through proper design of the program. While this is an intriguing idea, to date it is untried and unproven. If the program is workable it could certainly be applied to San Francisco, however the financing advantages of a CCA might prove to be of equal or even greater value. That is because the CCA can help customer with the costs of solar energy systems, and also use other tools such as selling investment shares in community solar projects, and using bulk purchasing to save money. These options are either more difficult or impossible for a city that lacks a public power system such as a municipal utility or CCA.

9. Recommendations

- **San Francisco's rollout of at least 360 MW of renewable capacity, combined with the other resources identified in this report, should allow closure of the existing peakers and the Mirant power plant under California Independent System Operator criteria for grid reliability in San Francisco without the need for another new transmission line.** The Board of Supervisors has directed the SFPUC (with the City Attorney) to study the feasibility of new transmission lines to serve San Francisco and to evaluate a "transmission only" solution to meet reliability needs. CCA's rollout of approximately 80 MW of qualified renewable capacity, along with demand reduction of 107 MW, construction of the 400 MW Transbay Cable, and construction of other local resources identified in this report, should allow for closure of the Mirant power plant and the peakers. However, if a transmission line is to be considered, it should be specifically designed to augment integration of the CCA Program's renewable energy facilities.
- **The CCA Program should prepare for the development of 106 MW of Cogeneration potential at sites where there are existing natural gas boilers in San Francisco.** SFDOE has identified at least 106 MW of new Cogeneration potential within the City at the sites of existing natural gas boilers, and the SFPUC is developing an efficiency retrofit program for SFPUC customer boilers. Cogeneration presents a major opportunity for a CCA for high quality local base-load power, and LPI recommends that SFPUC partner with the CCA Program to coordinate its boiler retrofit program with the CCA to make this energy resource available for electric generation. In addition, the City boiler retrofit program should be expanded to SFDOE so that potential CCA customer sites can also be developed as cogeneration facilities.
- **The CCA Program can make excess Hetch Hetchy power available to all San Franciscans, and CCSF, SFPUC and LAFCO should notify the Modesto and Turlock Irrigation Districts of CCSF's intention to do so.** We interpret the Raker Act to allow inexpensive SFPUC Hetch-Hetchy excess capacity to be made legally available to San Francisco ratepayers through the CCA Portfolio, and propose using a "split delivery" mechanism to structure the transaction in a manner consistent with the Raker Act.
- **The CCA Program should seek to purchase SFPUC-owned excess renewable electricity at cost for the CCA Portfolio.** Any SFPUC in-city renewable capacity or electric generation, including solar photovoltaic power, can be legally transferred to the CCA through direct purchases or "swaps". Transfer of credit for

excess power from solar facilities behind the meter of remote sites is possible between SFPUC customers. Allowing these "remote net-metering" transfers between SFPUC and CCA customers would require a change in state law.

- **The CCA Program should evaluate the option of using wind resources in the Delta, and other renewables, for generating electricity that can be delivered through the Trans-Bay Cable.** The Trans-Bay Cable should be accessible to provide transmission for the 150 MW wind farm required by the San Francisco CCA Program, making Delta wind an important option – though not the only candidate site – for the City's wind farm, and FERC rules give certain renewable energy resources such as wind power high priority for transmission access. Getting access to renewable resources outside of the City will require coordinated efforts to develop a wind farm, and access to a suitable site in a timely manner. Delay could impose a risk of significant additional costs.
- **CCSF should immediately petition the CPUC to become an administrator of the PGCEE Funds starting in 2010 and join other CCAs in the effort accelerate the CPUC process so that funds are available in time to support the CCA Program Implementation.** The Department of the Environment's Energy Efficiency program is in the process of being renewed, and a process should be put in place to terminate the portion of the partnership with PG&E that involves reducing electricity consumption. The City should petition the California Public Utilities Commission to allow CCSF to become the administrator of Energy Efficiency Public Goods Charge funds, and prepare City departments to plan a seamless change-over to the new CCA funding stream and program so that SFDOE resources are not interrupted or compromised by delays or funding gaps.
- **CCSF should rezone for certain CCA green power technologies, streamline overall renewable energy facilities permit processes, and restructure some existing permitting operations to prepare for the 360 MW rollout.** We find that significant progress has been achieved in improving the permitting and zoning process for solar photovoltaics, and progress made also with respect to certain kinds of wind turbines in Bernal Heights, but we call for further efforts, including potential legislation, to streamline San Francisco's zoning and permitting procedures and rules for renewable distributed generation, renewable storage, and efficiency measures in order to adequately prepare for the accelerated 360 MW rollout of renewables that is required by the CCA Program Design, Draft Implementation Plan and H Bond Action Plan, in advance of the RFP being prepared in coming months.

- **The CCA Program should perform Doppler tidal current measurement of the Golden Gate tidal resource and re-analyze economic feasibility of the site as a CCA facility.** While EPRI appears to have greatly overestimated the resource, URS found 1 - 2 MW of *mean usable output* of the Golden Gate Tidal resource. However, the URS deployment model was based on a facility with *maximum capacity* of 1.2 MW projected to operate at only 11% capacity factor, which means that its average output would be 10 times smaller than the 1 to 2 MW available resource that URS identified. CCSF should continue to study the viability and potential for tidal generation, including a potential pilot project to identify the feasibility of larger-scale deployment. The City should investigate options for reducing the cost of tidal power, including low or zero cost financing, grants, potential for scale up, and future technology that reduces the cost and improves performance and viability of tidal generation.
- **There are programs in other cities and utilities that are examples of elements that can be applied to the CCA program.** These include community owned solar projects, and public purchase of local solar green credits. Such programs help to establish the viability of these elements and provide examples for best practices.