Date October 24, 2008 Item No. 5

LOCAL AGENCY FORMATION COMMISSION

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Completed by: Linda Wong Date: October 22, 2008

***This list reflects the explanatory documents provided**

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Community Choice Aggregation
Program Report

Submitted to:

San Francisco Local Agency Formation Commission

October 17, 2008

by Local Power, Inc.

Contents

1. Background and Introduction

On August 20, 2008 the San Francisco Local Agency Formation Commission (SFLAFCO) directed Local Power Inc. (Local Power) to begin work on this CCA Program Report to outline and recommend a course of action relative to ongoing energy developments, public and/or private, that might be adapted to augment San Francisco's (the City's) Community Choice Aggregation and H Bond Program as adopted in Ordinances 446-07 and 447-07 last year, as well as the original CCA Ordinance 86-04 in 2004.

These ordinances outline the process for the SFPUC and SFLAFCO to prepare a Request for Proposals (CCA RFP) for Board of Supervisors approval to solicit Electric Service Providers (CCA Suppliers) to assume power supply responsibility citywide and build 360 MW of new renewable energy and demand-side technologies as part of the new service. In order to qualify, a CCA Supplier's bid must commit to a 51% Renewable Portfolio Standard (RPS) by 2017 including energy efficiency and conservation technologies, while also committing to meet-or-beat PG&E's rate schedule for all ratepayer classes initially, followed by a proposed structured rate into the future – including the costs of designing, building, operating and maintaining 360 Megawatts (MW) of new renewable energy capacity in or near San Francisco[1]. The 360 MW will be financed by the City using its voter-approved section 9.107.8 of the City Charter (the H Bond Authority), and will become all or mostly City-owned facilities. The CCA Program Report is intended to begin to identify opportunities and potential technical issues or conflicts that ongoing energy developments in the City present to the CCA Program's required 360 MW rollout.

More recent events contextualize the CCA Program Report. Most recently, SFLAFCO commissioned Michael Bell Management Consulting Inc. (MBMC, formerly serving SFLAFCO from R.W. Beck) to review prospective CCA Supplier responses to the San Francisco Public Utilities Commission's (SFPUC) 2007 CCA Request for Information (CCA RFI). In his analysis of these RFI responses,[2] MBMC confirmed the market approach of the City's adopted Draft CCA Implementation Plan[3], and recommended no major modifications of the Draft Plan, confirming its strategy and "meet-or-beat PG&E" rate structure. Specifically, Mr. Bell praised the City's decision to leave design flexibility for contractors while maintaining a strict, clear 360 MW renewable rollout requirement and an equally clear and ambitious but achievable 51% RPS by 2017. Moreover MBMC confirmed the Draft CCA Implementation Plan's careful placing of overall performance risk, revenue risk and design risk on the CCA Supplier through the Design, Build,

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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 447-07, (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] 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.
[3] Michael Bell Management Consulting Inc, "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.

Operate-and-Maintain mechanism,[4] while committing to competitive structured rates and shouldering the required performance insurance and bonds to cover any costs that might arise in a worst-case scenario.

The 360 MW rollout requirement includes at least 103 MW of local renewable distributed generation including at least 31 MW of photovoltaic capacity on private and public city rooftops, 107 MW in efficiency and conservation technologies in San Francisco residences and businesses, and a 150 MW wind farm. This Program Report addresses each of these (four) major categories. With a wide range of potential green technologies possibly coming into play in CCA Supplier Bids, a full range of available capacity and of serviceable load for the CCA Supplier is a critical factor enabling prospective suppliers to develop detailed rollout and portfolio strategies for their CCA RFP responses.

The essential structure of the City's program is to make an upfront public works-scale development of green power facilities a requirement of the CCA Service Agreement, with the H Bond financing repaid from monthly CCA Program electric bill revenues over the term of the agreement: presumably over more than a decade into the future from the date that customers switch over to the new service. The CCA Program structure places great emphasis on the ability of the CCA Supplier to implement an accelerated rollout of green power technologies within the City and County of San Francisco. This process will require (1) a data-rich environment in which locally available renewable, demand-side and clean power resource opportunities are identified, and (2) a rationalized rollout process in which unnecessary delays are minimized. A particular focus of this CCA Program Report is to identify resource opportunities and evaluate technical issues based on ongoing energy developments in the City. Some of these are City-sponsored projects such as the Mayor's solar program, while others are purely private sector developments such as the Trans-Bay Cable project.

Finally, per the Draft CCA Implementation Plan, the CCA Program is specifically focused on offering H Bond financing to all residents and businesses who wish to own their own solar array on their rooftop if their rooftop is structurally and directionally appropriate, or else have opportunity to own shares in a larger photovoltaic array if they are renters who own no rooftop and are therefore excluded from existing rebates or happen to have a north or east-facing rooftop ill-suited to solar power. Specifically, CCA removes the physical barrier to customer ownership of solar photovoltaics, eliminating the need for up-front capital without relying on a property tax assessment or a lucky rooftop owner. As CCA systems can be paid for on the customer's monthly electric bill, the benefits from different forms of ratepayer participation in different systems, whether an ownership share or hosting and purchasing benefits from hosted systems such as blackout protection[5] or facilities sharing,[6] is outlined in the Draft CCA Implementation Plan's section on potential opportunities for "islanding" of clusters of buildings on physically shared power systems. LAFCO's 2005 Nixon Peabody study of the use of H

[4] Draft CCA Implementation Plan, p.123.
[5] Draft CCA Implementation Plan, p.43
[6] Draft CCA Implementation Plan, pp.114-16.

Bonds to augment the CCA Program confirmed the financial legality of using H Bonds across the public and private sectors.[7]

Introduction

The City's leaders recognized the need to provide prospective CCA Suppliers with detailed information about the "landing strip" to expect when rolling out what will be a major new City- and community-owned green power infrastructure. The Draft Implementation Plan outlined a method of streamlining permit and government processes in order to facilitate the 360 MW rollout..[8] Simple math dictates that the ability of a CCA Supplier to achieve the required RPS acceleration and rollout will depend in part on CCSF's assistance in using its special CCA-based access to confidential energy usage data for purposes of CCA Program resource planning,[9] identifying and contacting candidate sites, and establishing streamlined processes of facility approval, permits and construction to expedite the overall process. Being location-sensitive, renewable technologies will require a concerted coordination effort 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, and thus a greater chance of success.

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 447-07 require the new CCA service to include a 360 MW rollout, which is a total value of about $1.2B, financed by approximately $600M in H Bonds. While the Draft CCA Implementation Plan does not establish an *a priori* limit to the duration of its CCA contract, the likely term will dictate a front-loading of the rollout in order to be financially viable. First, in Local Power's opinion, the 360 MW must functionally be installed and online within approximately three or four years after the initiation of service in order to be successful, based on the projected revenues of a 20-year CCA Service Agreement. According to the Draft Implementation Plan, if the opt-out rate exceeds 10%, 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.

The CCA Implementation Plan does not impose a firm rollout period but estimates a three-year rollout period,[10] a 20 year overall contract dictates that the 360 MW be built during the first few years of the agreement. If, as suggested by MBMC, a longer agreement such as 30 years were proposed and accepted,[11] a 51% RPS rollout would also

[7] Howard Golub and Travis Gibbs, Nixon Peabody LLC, Report to the San Francisco Local Agency Formation Commission, November 10, 2005 (Numbered S513427,7), Section (c), pp.8-14.
[8] Draft CCA Implementation Plan, p.118
[9] California Public Utilities Commission Decision 04-12-046, December 15, 2004, p.47, etc..
[10] Draft CCA Implementation Plan, p.34.
[11] Michael Bell Management Consulting Report to SFLAFCO, May 23, 2008, Recommendation #9, p.18

need to be completed during the first eight years. At issue is the "revenue adequacy" of the prospective CCA Supplier's proposal. As Ordinances 86-04 and 447-07 both require that the supplier commit to structured rates while achieving the RPS, "revenue adequacy" to support a bond based wholly on the CCA Contract and identifiable subsidies, charges and premiums based on a committed rollout schedule, is a time-sensitive undertaking; it must be completed by a certain date in order to remain profitable. Time is of the essence; 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 based on monthly electric bills minus the City's H Bond debt service. In short, the H Bonds must be fully replenished by CCA revenues within the term of the CCA Agreement.

Second, the overall 51% Renewable Portfolio Standard required by the Draft CCA Implementation Plan[12] will only be partly achieved by the initial 360 MW rollout, which will itself provide 20% of all power consumed annually by San Francisco ratepayers. To get to 51% RPS by 2017, suppliers who do not elect to build the RPS will have to buy green power at a premium, and are thus strongly incentivized to propose a Phase II rollout scenario in addition to the required 360 MW rollout. In order to undertake a second H Bond authorization, this could be achieved by either a second H Bond issuance by extending the initial CCA Service Agreement to support the second investment, or a 30-year contract duration to achieve the whole objective in a single CCA Service Agreement and a single H Bond authorization of the Board of Supervisors.

The CCA Program Report is an initial survey of opportunities to provide a firmer foundation for prospective CCA Suppliers to meet a higher standard of performance with more competitive electricity rates. The Program Basis Report will provide a complete 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.

Our Approach

Contributors for LPI include Paul Fenn, Robert Freehling and Mike Marcus of LPI, Howard Golub of Nixon Peabody, Bill Powers of Powers Engineering, as well as Joe Speaks from Booz Allen Hamilton. 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. Based on these contributions and others, LPI has conducted research and analysis with the intention of identifying feasible energy projects for possible inclusion in the CCA Program, evaluate benefits of complementary government programs to the CCA Program , and evaluate each identified project for inclusion in the CCA Program scope, considering factors such as technical integration, overall implementation time

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

requirements, and whether there would be any significant siting and/or permitting issues, and also analyze areas where ongoing City energy projects may potentially impact or work constructively with the CCA Program, including: (1) use of common funding sources; (2) jurisdiction and ownership issues; and (3) technical or business interface issues.

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, and has to date received answers to many but not all of these questions as of the release date of this document.

Finally, Local Power has undertaken a Best Practices Survey of Other Green Portfolio Programs operated by investor-owned or municipal-owned utilities in California and other states, that may be compared to or otherwise provide precedents for key elements of the City and County's CCA and H Bond Program.

This report incorporates comments and feedback from SFPUC, SFLAFCO and SFDOE staff. Local Power 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. As a courtesy, similar review and comments were solicited and received from SFDOE staff, and this feedback too was incorporated into the report.

2. Major Conclusions

This report arrives at a number of major conclusions about opportunities, barriers and technical issues presented to the CCA program by a number of ongoing energy developments:

- **We conclude that San Francisco's rollout of at least 360 MW of renewable capacity, energy efficiency and conservation measures (210 MW within the City's jurisdictional boundaries) should allow closure of both the existing peakers and the Mirant power plant under California Independent System Operator criteria for grid reliability in San Francisco without the need for a new transmission line**, but that if a transmission line is to be considered, it should be specifically designed to augment integration of the CCA Program's renewable energy facilities rather than merely make the City more energy dependent.
- **We dispute the URS study of the Golden Gate Tidal resource and recommend immediate implementation of actual physical measurements onsite at the optimal location, and propose consideration of a potential renewable-only transmission line out to the Golden Gate site.** While URS found 1 - 2 MW of *mean usable output* of the Golden Gate Tidal resource, its deployment model was based on a facility with *maximum capacity* of 1 MW. This facility was projected to operate at only 11% capacity factor, which suggests a mean output 10 times smaller than the 1 to 2 MW available resource. URS acknowledged that their tidal model may have underestimated the real resource, and focused on a location under the bridge even though their model showed better resources outside the Gate. They also omitted cost savings from public financing available to a CCA. These factors exaggerated the cost of electricity from local tidal generation.. EPRI's study appears to overestimate potential capacity at the site, but used a more sophisticated financial and technology deployment model that included CCA and municipal financing. Combining the strengths of both studies, Local Power found a significant resource that may be economically feasible for CCSF to develop as a component of the CCA Program. We recommend that monitoring instruments be placed at optimal locations in the tides for live data, rather than depending on computer models. The City should re-evaluate the resource based on the CCA and H Bond financing required by Ordinance 86-04 and 447-07.
- **We highlight over 100 MW of Cogeneration (capturing existing boiler waste heat and converting to electricity) potential on existing natural gas boilers** that have been identified for efficiency measures by San Francisco Department of the Environment, as well as yet-unidentified SFPUC customers that the SFPUC is targeting appropriate efficiency measures. SFDOE has identified over 100 MW of new Cogeneration potential within the City on natural gas boilers, and the SFPUC is developing an efficiency retrofit program for SFPUC customer boilers. We find that cogeneration presents a major, opportunity for a CCA, and recommend 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.

- **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.
- **Any SFPUC in-city renewable energy capacity, including solar photovoltaic capacity, can be legally transferred to San Francisco ratepayers through the CCA Portfolio.**
- **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 for the City's wind farm, and FERC rules give certain renewable energy resources such as wind power the highest priority of 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.
- **The Department of the Environment's Energy Efficiency program is in the process of being renewed, and an urgent direction is needed to petition the California Public Utilities Commission to allow CCSF to become the administrator of Energy Efficiency Public Goods Charge funds. Further, CCSF should prepare to terminate the PG&E Partnership** for power efficiency by resolution of the Board of Supervisors according to schedule that allow a seamless transition for SFDOE staff to the new CCA funding stream, so that established SFDOE services are not interrupted or compromised by unnecessary delays or funding gaps.
- **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** in order to adequately prepare for the accelerated 360 MW rollout of renewables that is required by the CCA Program, in advance of the RFP being prepared in coming months.
- **We report on programs in other U.S. 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.

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,"[13] 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.

Potential Benefits of Hetch Hetchy Power to CCA Program. Hetch Hetchy power is non-renewable but is a relatively green, existing, low-carbon, and perhaps most importantly, a very cheap energy resource, which could function as the key "cheap, brown" component of San Franciscans' power supply. Much cleaner than new natural gas fired generation that PG&E has financed, or with coal or nuclear power, Hetchy is a least of three evils that the CCA Program would be irresponsible not to make every effort to include in the CCA Program already-owned resource portfolio, for the dirty 49% of San Francisco's remaining supply infrastructure that will remain to be replaced in 2017.

Technical Issue. Currently, Hetch-Hetch capacity is limited to a government 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 Hetchy power. Special categories of private sector customers - such as the JCDecault 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."[14] Similar arrangements were also made during the 1980's. Hetch-Hetchy capacity is not really firewalled. More recently in the City's PG&E Interconnect Agreement renewal last year, the SFPUC negotiated a swapping arrangement with PG&E and won passage of state legislation to allow it to swap SFPUC customer meter or grid-connected power facilities, limited within a 20 mile radius of San Francisco, with PG&E. Most recently, in LPI's interview of SFPUC Power Enterprise Assistant General Manager Barbara Hale, she expressed her agency's interest in swapping power with the SF CCA in a comparable manner to that proposed for PG&E.

Currently, however, both transactions for Hetch-Hetchy Dam and from certain SFPUC-owned solar power whose output is owned by PG&E, continue to exclude San Francisco residents and businesses. An unspoken firewall has separated most San Franciscans from enjoying the benefits of their federally mandated Hetchy power since the dam was built. Currently, any excess capacity from Hetch-Hetchy not consumed by City Agencies or a lucky elite of San Francisco ratepayers, must be sold to two Central Valley irrigation districts serving the Modesto and Turlock regions. While this disposition of San Franciscans' hydropower plant reflects a political refusal to municipalize PG&E's system (though there is now an initiative on the ballot for November 2008, this treatment is no longer necessary given the CCA Program's specific mandate of providing power to the very private sector that the SFPUC has heretofore been unable to serve. CCA provides the customers for a retail channel to enjoy the benefits of Hetch Hetchy power. Under

[13] Draft CCA Implementation Plan, p.93.
[14] Agreement Between Pacific Gas & Electric Company and City & County of San Francisco, 2007, p.4.

law, the SFPUC may now finally convey this historic public resource to benefit any San Franciscan who wants it.

Section 6 of the Raker Act in essence prohibits San Francisco from selling the water or electricity from Hetch-Hetchy to “any corporation.”[15] 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-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.

Implementation Time Required. There are several factors that could 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 (slightly over 100 pages, plus 31 appendices) document could also 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 are currently in litigation over the Agreement. 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 privileged analysis of these issues.[16]

Potential Impacts to the CCA Program. LPI has conducted an initial review of the City 2007 Agreement with PG&E. That review preliminary indicates that it should be feasible to structure a similar arrangement with the Supplier insofar as Raker Act compliance is concerned. Nonetheless, 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: using its rights to transmission under the Federal Power Act, the City could 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 plus the Supplier’s portfolio which together 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.

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15 United States v. City and County of San Francisco 310 U.S. 16 (1940).

16 LPI has requested SFPUC data on unused Hetch Hetchy capacity and related SFPUC customer load data from the SFPUC Power Enterprise Division, but has not yet received this data as of the date of this document’s submission to SFLAFCO; when and if the data is received, LPI will

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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 an important potential resource for the City's adopted 51% RPS requirement because it could provide a very high quality supply of power that should be cost-effective. The initial study by URS Corp has indicated that the Golden Gate Tidal resource would not be effective. Local Power has reviewed this work and evaluated it in light of the unique variables of the CCA program. A key question in reviewing the PG&E study by URS Corp working for SFPUC is to illustrate the specific benefits of the Golden Gate to CCA as a local source of power, compared to its generic market value to an entity such as PG&E.

Golden Gate Tidal Resource. The entire central valley water system, the Sacramento, San Joaquin, Stanislaus, American and other rivers all 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 this relatively narrow opening to the sea at the Gate. Numerous studies have been performed to determine whether this movement of water would be adequate to generate electricity in significant quantities and at competitive prices.

There is considerable divergence of opinion on the availability of tidal power in the Golden Gate. Should harnessing tidal power prove to be cost-effective, the Golden Gate tidal resource could be an important potential resource for the City's adopted 51% RPS requirement.

To answer this question three studies have been performed over the last few years, all by organizations that carry weighty credentials. These reports came to very different conclusions about the available resource, cost and performance of tidal generation at the Gate. Their determination of whether tidal power is in fact viable depends on assumptions that have not been well verified by actual measurements, but only by mathematical models—ranging from simple to relatively complex— that may or may not be accurate.

Analysis of the EPRI Report

The first report, by the Electric Power Research Institute, was conducted in 2005 as part of a much larger collection 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 contradistinction to the robust financial analysis, the assessment of the tidal resource at the Gate turned on a very simple calculation. A line was drawn on a map 500 meters upstream of the Golden Gate Bridge which goes through a NOAA buoy. The buoy is 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.

The 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. The also recommend a more detailed resource assessment be carried out to account for these effects.

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 operating at a capacity factor of 33%. They conclude that the 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, Local Power derives 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 demo 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 muni or CCA. Both of these are concluded 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 1.5 cent per kilowatt-hour payment for renewable generators built by public power agencies. Unfortunately, the account that pays for this program is rarely if ever funded.

- <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 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 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 129 gigawatt-hours per year of green energy. For a CCA this represents only about 3% of the City's electricity supply at a relatively small premium compared to expected future energy costs. This would have minimal effect on customer rates—Local Power estimates that a CCA owned and financed

Analysis of the URS Report

The second report is by URS, a major engineering firm well experienced in infrastructure projects. Their analysis leads to exactly the opposite conclusion as the EPRI report, namely that the tidal resource is eight times smaller than what EPRI came up with, and development of tidal power at any scale is economically infeasible. Essentially, they are saying that the usable resource is zero.

The trip from EPRI's 237 megawatts to URS's zero 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 the primary real world reference measurement set in either model. They both applied the correct mathematical law for the tidal currents, that power of the current is proportional to the cube of velocity. Both had similar models for tidal flows according to the semidiurnal, diurnal and monthly cycles.

Both also had similar data for characteristics of tidal generators, and what they would cost if built to significant scale. 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 resultsThe 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. 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 value for power resource was 1/8th, which would be about 30 megawatts. Of this resource, they estimated that only 10% would be developable, which should lower the amount to 3 megawatts or less.

The report then examined only the possibility of a single tidal generator unit of about 1 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. Local Power recommends that CCSF install current monitoring equipment and undertake an updated analysis of the tidal resource based on a CCA-specific application to supplement the theoretical models that have already been used to confirm whether the Golden Gate is an economically viable resource for development by the CCA Program.

This recommendation is based on a thorough analysis of the URS study, which identified significant methodology questions. The descent from 237 megawatts to zero is dependent on some questionable assumptions, despite URS's impressive computer modeling for tidal currents which far exceeded what EPRI offered. To begin with there are several weaknesses in the URS model that are revealed within the URS report itself. They point out that the simulated month long computer test 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 month-long simulation understates the longer simulation by the cube of speed, so the higher 6 month result would generate almost 25% more power.

In addition, an examination of the tidal maps generated by their simulation show that considerably better resource exists to the west of the bridge. If this site were chosen instead, then the power resource might be even better. In fact, since only a fraction of the tidal resource would be tapped, the possibility is strong for finding a specific location with higher resource than what is indicated by the average or "mean" resource.
A weakness of both studies is reliance upon abstract models and a deficiency of actual measured data. A study performed at the US Naval Postgraduate School at Monterey performed real measurements from the Bay floor directly at the Gate for a period of over a month. The results showed tidal energy resource that is far 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 real-world measurement of the Golden Gate tidal current is in order. This is especially critical due to the ease with which very 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 to about 10 megawatts to get considerable unit savings on installed capacity. In addition, a CCA has the advantage of low cost bond financing of near 5%, a point noted in the EPRI study. The URS study failed to use this tool of low cost financing, which would have further lowered the cost.

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 Department of Environment mapped out the permitting process in a Tidal Power Permitting Matrix.[17] The matrix accurately shows that the City and County of San Francisco must play the role of applicant, not regulator,

[17] See Attachment B.

in the development process, should the CCA Program include development of this project as part of its rollout.

Tidal Power Facility Permitting Agencies[18]

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

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

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[18] Please see attached DOE Golden Gate Tidal Power permitting matrix, Attachment B.

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

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, 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 Task Force released its Summary of Recommendations report in December, 2007, which included having the City create its own solar rebate program to supplement the rebates already offered by the state under the California Solar Initiative. The rebates were recommended for a few stated reasons. San Francisco, which has 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.[19] 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 cells.[20] An additional good reason 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. 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 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.

[19] Ordinance 102-08, File No. 071679, Approved 6/18/2008.
[20] Draft CCA Implementation Plan, p. 14

Another concern is interaction with federal tax credits, which have been set at 30% of installed cost in recent years, and that might be extended under legislation now under consideration in Congress. 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 rebate.

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 economy of scale.

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.

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." 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

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.[21] 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 at a 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.

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 easily exceed the 50 megawatt goal for the City adopted in the CCA Implementation Plan. The main questions for a CCA are whether these projects will in fact all get built, the degree coordination of planning and operation with the CCA, and whether power transactions such as resale and swaps can occur. Whether or

[21] See Appendix XX.

not all the SFPUC facilities get built, the CCA plans to build its 25 megawatt (ac) share of photovoltaics this is essential to its goal of relying on local clean energy.

iii. Solar Power transactions between SFPUC and the CCA

SFPUC is planning to build over 60 megawatts of solar power facilities in San Francisco by 2012 or so. There is potential to sell excess power from any solar plants built by SFPUC or their 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.

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 Racker Act.. 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.

It is clear, however, that there could be real benefits from coordinating the resources of SFPUC and the CCA. *Local Power recommends that planning and operation of renewable generators and other resources that can back these up, and transactions between the two entities, be coordinated to significantly improve the reliability of renewable power supplies.*

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 dramatically changed 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.

c. Wind Turbines

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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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 is 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

<u>Recommendations</u>

<u>Rezoning Ordinance</u>. 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 a resolution for the Board of Supervisors to 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. Opportunities for Cogeneration through the City's Natural Gas Efficiency Program

Introduction. A CCA will need to find local clean electricity supplies that are reliable and affordable. 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. 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 simply waste. Because the technology is classed as natural gas-based, it is not "renewable." So while 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. Therefore it is a highly advisable resource development strategy.

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.[22] 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. Sixty (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.[23] 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.

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[22] K. Davidson – DE Solutions, *Combined Heat and Power*, PowerPoint presentation, Carlsbad Chamber of Commerce Sustainability Committee Forum, October 3, 2008.
[23] 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

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.[24]

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).[25]

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 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.[26] 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.

[24] Ibid, p. 1.
[25] Ibid, p. 1.
[26] Ibid, p. 10.

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).[27] The carbon footprint for a baseload combined cycle plant is approximately 820 lb CO_2 per MWh.[28] 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.[29] 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.[30] 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.[31] 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.

[27] 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.

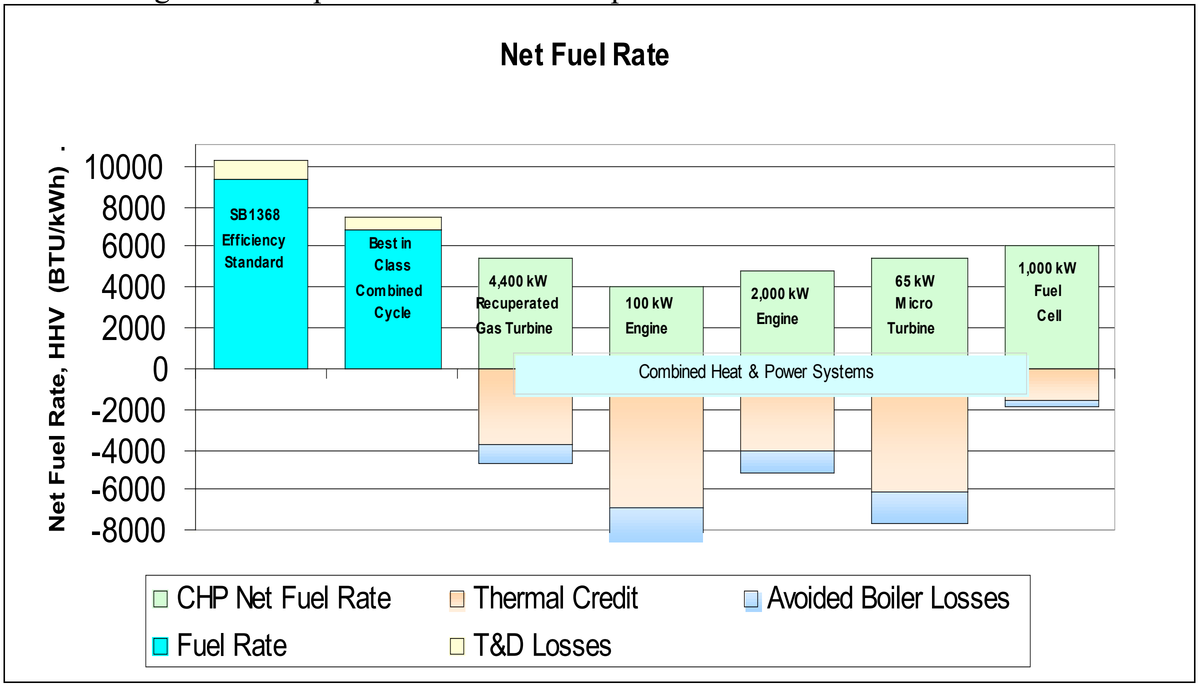
[28] Assumed heat rate of a combined cycle power plant is 7,000 Btu/kWh at baseload (full power) operating conditions. Multiplying by the natural gas CO2 emission factor gives a CO_2 emission factor for combined cycle of approximately 820 lb CO_2 per MWh.

[29] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, December 2007, p. 61.

[30] 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.

[31] 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[32]



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.

[32] 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.[33] 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.[34] 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.[35]

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.[36] 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:[37]

> "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

[33] June 2005 FERC approval of rate schedule for Trans Bay Cable.
[34] NEED LINK TO CEC SGIP WEBSITE.
[35] Excerpt from California Energy Circuit, *State Sees DG Providing 25% Peak Power*, May 11, 2007, p. 8.
[36] Tecogen case study brochure, CM-60 and CM-75 Cogeneration Modules – 1080 Chestnut Street, San Francisco, www.tecogen.com.
[37] 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.[38] 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
- Reduced fossil fuel consumption
- Reduced carbon emissions

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[38] Ibid.

- 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 Department of the Environment for the City and County of San Francisco commissioned a June 2007 study of CHP potential in San Francisco that summarizes potential CHP opportunities.[39] 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.

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

[39] 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.

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.[40] 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.[41]

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 percent. A PureComfort® system is in operation at the Ritz-Carlton Hotel in San Francisco.[42]

<u>Downtown steam loop CHP</u>. 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.[43] A description of the proposed downtown steam loop plant upgrade is provided as **Attachment A**.

[40] 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.
[41] B. Powers, San Diego Smart Energy 2020, October 2007, p.
[42] UTC webpage, PureComfort® Solution Applications. See: www.fuelcellmarkets.com/united_technologies_utc
[43] Telephone conversation between B. Powers, Powers Engineering, and S. Hoffmann, NRG West, September 18, 2008.

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.[44] 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 DOE 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.

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).[45] This compares to a retail natural gas utility charge to residential customers of $12/million Btu for natural gas.[46] 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

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[44] 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.
[45] Telephone conversation between B. Powers, Powers Engineering and R. Lyons, Syska Hennessy Group, September 19, 2008.
[46] SDG&E invoice to William Powers, natural gas invoice for July 2008, energy charge of $1.23 per therm or $12.30/million Btu.

second is onsite and empty, and the third is in route with a full supply of biogas.[47] 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.[48]

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.

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.

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[47] Telephone conversation between B. Powers and F. Mazanec, BioFuels, Inc., Escondido, CA, October 13, 2008.
[48] K. Brennan – PG&E, California Emerging Clean Air Technology Forum Stationary Source Session - Energy Generation From Digesters, July 9, 2008.

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.[49]

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 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.[50] 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.[51] The maximum system size is 5 MW. The minimum size is 30 kW for wind turbines and fuel cells using renewable fuels.[52] SB1012 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

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[49] Telephone conversation between B. Powers and F. Mazanec, BioFuels, Inc., Escondido, CA, October 13, 2008.
[50] California Legislative Counsel's Digest, text of AB 1613, November 15, 2007.
[51] PG&E SGIP webpage: http://www.pge.com/mybusiness/energysavingsrebates/selfgeneration/equipment/
[52] http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA23F&state=CA&CurrentPageID=1

receives 25 percent of the incentive rate. Systems must be sized according to customer's electricity demand. The one-time SGIP incentive payments are:

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 (SB1012 proposed):	$ 600/kW
Microturbines (SB1012 proposed):	$ 800/kW

Cogeneration Zoning and Permitting

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Background

Cogeneration systems, also known as combined heat and power 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. In June 2007, the Department of the Environment 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 Department of Environment (DOE) 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 DOE 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 revolutionary device manufactured by Tecogen, which is previously mentioned in this report.

Permitting

Cogeneration systems, also known as combined heat and power systems, require a series of permits issued from a variety of jurisdictions, as outlined in a June 2007 Department of the Environment report by Dr. Philip M. Perea, titled *An Assessment of Cogeneration for the City of San Francisco*. 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.

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. Local Power'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.

Given the complexities of large-scale permitting efforts, political will is of extreme 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, Local Power 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, with possible intervention by the California Attorney General's office.

e. In-City Renewable Generation Projects for Grid Reliability

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.[53] 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.
, and would dictate specific ownership and control attributes in order to avoid negative impacts and facilitate positive ones.

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

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

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. As far as reliability needs are concerned, this 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 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. This involves four turbine units that were given to the City as part of an environmental settlement. However, the peaker turbines have turned out to be something of a Trojan horse. For years these proposed natural gas fired power plants were considered to be the primary solution to the City's reliability needs. However, recently, with the construction of the transbay cable virtually certain, the need for power plant capacity has been reduced the equivalent of one peaker unit. As for the remaining three units, considerable expense would be involved in putting them into operation, with the mayor's office projection $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 involve replacing the existing 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. The forth 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.

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 well over 1 megawatt of solar electric power, at sites such as the Moscone Center, the Port, and other locations. The current aim of city planners is to install enough to bring the total up to 10 megawatts by 2010. The reliability factor for photovoltaics is rated at about 39% in PG&E's territory, so the total planned SFPUC goal would count as 3.9 megawatts toward reliability needs under the current utility planning.

Energy Efficiency. The next cycle of planning by SF Department of Environment 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 SF Department of Environment last 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. For San Francisco as a whole this share would be equivalent to 47.5 megawatts, though data acquisition will be necessary to find out what the actual amount of Demand Response resource is actually 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 SFPUC if this is not already the case.

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 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. 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 savings. 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 SF Department of Environment, 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 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. It is very likely that 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. These can be sited at a relatively small location. Another option that can be explored is to see whether there are potential sites on the peninsula for pumped water storage. 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.

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.

<u>Golden Gate Tidal.</u> There is considerable divergence of opinion on the availability of tidal power in the Golden Gate. The range is from just a couple megawatts, to as much as over 30 megawatts. Using current technology, much of which is still in development, is not likely to prove cost effective unless at least 5 to 10 megawatts of capacity is installed. This power supply is intermittent, though—unlike wind—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.

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 10 megawatts of solar energy, peak demand reduction, ongoing energy efficiency programs of SF Department of Environment, 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, 30 megawatts of solar energy, 107 megawatts of efficiency improvements, and 72 megawatts of distributed generation. A phase 2 CCA program could add even more.

f. CCA Program Zoning and Permitting Issues

<u>i. General Discussion and Recommendations</u>

Zoning and Permitting are key challenges for the CCA projects, because the CCA Program Design adopted by 447-07 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 Department of Environment 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 *Environmental Protection Element* 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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Department of Building Inspection
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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 Department of Environment 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 Department of Environment 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.

<u>Permit Center</u>

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

Both Ordinance 447-07 and 86-04 require for 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 447-07 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, which will amount to $4.5-6M per year, 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 on this matter and commit resources to becoming an administrator of Energy Efficiency PGC funds starting in 2009 according to the timeline ordered by Ordinance 446-07 and 447-07, and terminate the PG&E Partnership at a date that will ensure a seamless transition of SFDOE staff from the PG&E Partnership electricity Programs[54] to its management role in the rollout of 107 MW of Energy Efficiency and Conservation measures required of the CCA Supplier by the CCA Program.

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 – a $14M-$18M value that may be lost to the CCA Program. When approved, this will effectively lock up funds that would otherwise be available to the CCA Program. On this subject, SFPUC Assistant General Manager Barbara Hale suggested in an interview with Local Power 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 exhaustively debated and adopted policy and would violate both Ordinance 447-07, which required SFDOE to be prepared to terminate its Partnership with PG&E upon initiation of CCA Service and to undertake a transition to the management role defined by the Draft CCA Implementation Plan, so that the City can seek to be an administrator of PGCEE funds and the 107 MW Energy Efficiency

[54] SFDOE also has a natural gas efficiency partnership program with PG&E that should not be terminated at this time, as the CCA Program does not include natural gas efficiency.

rollout can be implemented as required by the CCA Supplier with support of these funds starting in 2009.

<u>Significance to CCA Program.</u> Ordinances 86-04 and 447-07 require CCA Supplier bids to include the cost of installing 107 MW of energy efficiency and conservation measures throughout the city, for the simple reason that the significant savings from energy efficiency measures, are so cost-effective when adapted to local needs that they cause savings rather than in incur costs. While the City's CCA RFP Process is expected to initiate CCA Service in 2009, the SFDOE PG&E Partnership would lock in funds until at least 2010, meaning the funds would not be available to support the 107 MW rollout 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, underscoring 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. Specifically, 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. At the same time, in order to start this process, CCSF must initiate a protocol to terminate SFDOE's recently renewed PG&E partnership, which occurred under SFPUC administration and approval process.

In order for CCSF to directly administer Energy Efficiency Public Goods Charge Funds to support the CCA Program investment in Energy Efficiency, CCSF must petition the California Public Utilities Commission immediately to become an administrator of funds paid by participating San Francisco customers starting in 2009, and invite other California municipalities and counties to cooperate with the City in its regulatory effort. A California Public Utilities Commission workshop on CCA administration of energy efficiency public goods charge (PGC) funds is 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.[55]

[55] 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.

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.[56]

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.[57]

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

[56] 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.
[57] 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.

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).[58] 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

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.[59]

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.[60]

[58] Ibid, p. 4.
[59] Ibid, p. 6.
[60] SFPUC, response to Local Power question 2C.

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.

PG&E Rate Schedule FERC 114 provides an off-the-shelf template for an interconnection agreement between the City and CAISO for transmitting power generated from a Solano County wind farm, or similar utility-scale renewable energy development, over transmission lines under CAISO control.

c. City of San Francisco Will Receive 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 powerflow over the TBC.

7. Ongoing In-City Distribution Developments.

The Board of Supervisors has 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 it remains unclear whether the voters will elect to authorize a municipalization of PG&E's system, 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 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.

Local Power 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[61]

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.[62]

[61] 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.
[62] Financial Services Project Budget Report, Energy Services CUH979, SFPUC

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."[63]

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 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

[63] *Ibid.*

transmission cable has been installed from East Bay Port of Oakland Davis Substation to Treasure Island.

MUNI Distribution System

Local Power 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.

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

8. 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 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 rebates 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. 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.

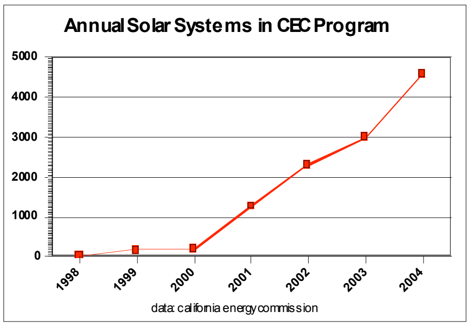
By 2010 the CSI rebate rates, administered through the utility companies, are certain to be lower than they are today. This means that the stimulus value will be greatly reduced, especially when the rebate for most customers falls to $0.65 per watt and lower. At the seventh tier, a $25,000 home system 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.

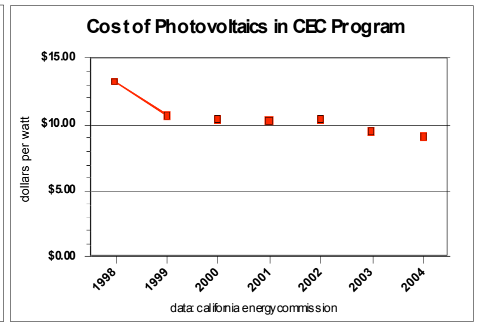
Without intervention, either by reduced market prices or by improved public support, the CSI program is likely to stall somewhere between the 5th and 7th tier. This will leave about 1000 megawatts remaining to be built out of the utility total of 1850 megawatts. A local rebate, or other local program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

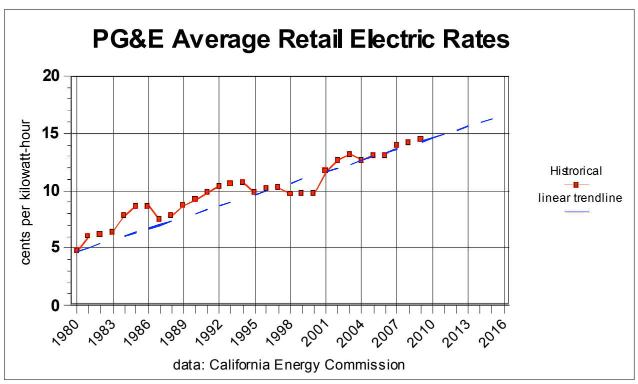
The data suggest that 60% of the rebate value is being transferred to installers and manufacturers. Despite the fact that the consumer has to share the rebate with the industry, the overall benefits of the rebate policy have been significant. The primary purpose of the solar rebate programs is to stimulate 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 illusory.

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. [64] 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, [65] 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.

Solar Rebates. 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

[64] 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.

[65] 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 [66], 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." [67] 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.

<u>SMUD SolarSmart Homes.</u> 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." [68] 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.

<u>SMUD SolarShares.</u> 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

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

[68] *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.

Local Power 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.

City of Ellensburg Community Solar Project

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." [69]

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 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 [70], 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.

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[69] http://www.ashland.or.us/Page.asp?NavID=10994
[70] http://www.b-e-f.org/renewables/ellensburg.shtm

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.[71] 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% 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.

[71] 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

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. 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[72] 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. [73] *Such purchasing of local solar RECs from customers inside the City’s jurisdiction is specifically recommended under San 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.*

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

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.[74] 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. [75]

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.

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.

[74] 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.
[75] http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf

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

- **CCSF's evaluate of the transmission-only option to closing the Portrero plants should be undertaken with a view to augment the CCA Program's renewable energy rollout.** San Francisco's rollout of at least 360 MW of renewable capacity, energy efficiency and conservation measures (210 MW within the City's jurisdictional boundaries) should allow closure of both the existing peakers and the Mirant power plant under California Independent System Operator criteria for grid reliability in San Francisco without the need for a new transmission line currently being studied. Any consideration of transmission should focus on how to help augment renewable energy development and increased energy independence in San Francisco.
- **The CCA Program should implement physical tidal current measurement of the Golden Gate tidal resource and re-analyze economic feasibility of the site as a CCA-specific facility.** While URS found 1 - 2 MW of *mean usable output* of the Golden Gate Tidal resource, its deployment model was based on a facility with *maximum capacity* of 1 MW. This facility was projected to operate at only 11% capacity factor, which suggests a mean output 10 times smaller than the 1 to 2 MW available resource. URS acknowledged that their tidal model may have underestimated the real resource, and focused on a location under the bridge even though their model showed better resources outside the Gate. They also omitted cost savings from public financing available to a CCA. These factors exaggerated the cost of electricity from local tidal generation.. EPRI's study appears to overestimate potential capacity at the site, but used a more sophisticated financial and technology deployment model that included CCA and municipal financing. Combining the strengths of both studies, Local Power found a significant resource that may be economically feasible for CCSF to develop as a component of the CCA Program. We recommend that monitoring instruments be placed at optimal locations in the tides for live data, rather than depending on computer models. The City should re-evaluate the resource based on the CCA and H Bond financing required by Ordinance 86-04 and 447-07.
- **The CCA Program should prepare for the development of 106 MW of Cogeneration by capturing existing natural gas boiler waste heat in San Francisco.** SFDOE has identified over 100 MW of new Cogeneration potential within the City on natural gas boilers, and the SFPUC is developing an efficiency retrofit program for SFPUC customer boilers. We find that cogeneration presents a major, opportunity for a CCA, and recommend 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 renewable generation at cost for the CCA Portfolio.** Any SFPUC in-city renewable energy capacity, including solar photovoltaic capacity, can be legally transferred to San Francisco ratepayers through the CCA Portfolio through direct purchases or energy "swaps". Credits for excess capacity of solar facilities behind the meter of remote sites is available between SFPUC customers. Allowing this "remote net-metering" transfer between SFPUC and CCA customers would require a change in state law.
- **The CCA Program should seek to develop a wind farm in the Delta for delivery 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 the highest priority of 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.
- **CCSF should immediately petition the CPUC to become an administrator of the PGCEE Funds starting in 2009 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 partnership with PG&E. To facilitate a seamless transition for SFDOE staff, it will be necessary to petition the California Public Utilities Commission to allow CCSF to become the administrator of Energy Efficiency Public Goods Charge funds, and to 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 adopted by Ordinance 447-07, in advance of the RFP being prepared in coming months.

- **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.