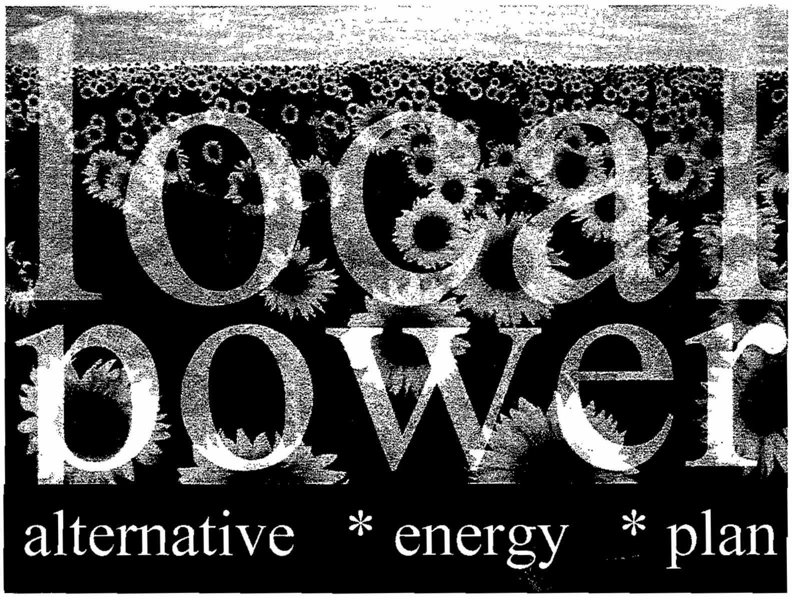

Green Energy Options
to Replace the South Bay Power Plant

Alternative Energy Plan on the Feasibility and Cost-Effectiveness of Replacing the South Bay Power Plant by 2010 With Local, Competitively Priced Green Energy Sources

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1. Executive Summary

Background and Purpose

The existing South Bay Power Plant, over 40 years old, is outdated, inefficient to run, devastates the South San Diego Bay ecosystem and pollutes the air. The power company LS Power, all of whose merchant power plants (including the South Bay Power Plant) were recently acquired by Houston-based Dynegy[1], is in the permitting process for a South Bay Replacement Project (SBRP) which includes the demolition of the current South Bay Power Plant and the construction of a new gas-fired power plant near the current site. There is little disagreement that the existing plant needs to be shut down. There is debate, however, about how the energy capacity provided by the existing plant should be replaced. This decision will shape the region's energy future, the health of Chula Vista residents, and the character of the Chula Vista Bayfront for decades to come.

The SBRP decision will have global impacts. Climate Crisis is upon us. Power plants are the largest cause of greenhouse gas pollution in the United States, which as a nation is the world's largest greenhouse gas polluter – and California's greenhouse gas emissions have continued to increase for the past fifteen years. A major opportunity to answer the Climate challenge is in our front yard, and will shortly present itself for local decision-making. In the Chula Vista region, by far the largest single cause of climate pollution is the South Bay Power Plant. While Dynegy's acquisition of the plant has increased pressure to approve a larger power plant replacement, green power alternatives – and the means to develop them cost-effectively – now exist, which if developed by Chula Vista and potential local partners will render power generation at the South Bay Power Plant site unnecessary for the regional transmission grid. Recognition of urgency and opportunity is essential to solving the Climate Crisis. The SBRP decision may be the community's only major chance to do something about this mounting catastrophe.

While the existing plant runs at a relatively low capacity most of the time, it does provide 700 Megawatts (MW) (reduced to 515 MW for 2007) of "Reliability Must Run" (RMR) capacity to the grid, a special designation instituted to ensure grid stability. A number of options exist to provide the energy and capacity that the San Diego region will need into the future, including demand response, renewable energy, natural gas plants in other parts of the County, and other options. For a number of reasons – to protect public health and promote environmental justice, to protect our economy from over dependence on natural gas with its price volatility, to reduce greenhouse gas emissions, and to meet state-mandated requirements for renewable energy – the replacement of the existing South Bay Power Plant should include a major commitment to green energy options. This report identifies and analyzes local opportunities for more sustainable, secure energy development in San Diego County in order to reduce the need for, or the scale of, a natural gas generation facility to replace the South Bay Power Plant (SBPP).

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[1] On September 15, 2006, Independent Power Producer Dynegy announced it has agreed to pay more than \$2B in stock and cash for the merchant plant portfolio of private equity fund LS power Group, including SBPP and eight other power plants acquired from Duke Energy for \$1.6B in May. LS Power Group will retain a 40 percent stake in the combined company. Dynegy's management team, including CEO Bruce Williamson, will run the company.

The "Green Energy Options" (GEO) outlined in this report, demonstrate how Chula Vista and neighboring communities can now move to develop solar, wind and other green power technologies at market prices, stabilize local electricity rates, win energy independence, and eliminate a major contributor of pollution and greenhouse gases. The City of Chula Vista has already taken a leadership role in promoting energy sustainability and taking responsibility for reducing the hazards associated with the global climate crisis. By investing in energy development described in this Green Energy Options report, the City of Chula Vista can take a major step toward ensuring energy and economic security for Chula Vista and the region, and can set an example for the region, state, and beyond.

Summary of the Green Energy Option Portfolios

The Green Energy Options (GEOs) described in the report are viable, and the technologies are readily available. The GEOs are three electric energy portfolios designed to meet three different levels of capacity replacement for the South Bay Power Plant. They address a range of possible regional needs and provide a range of investment options. The current power plant supplies electricity in the period of high demand during the day and early evenings, and the GEO portfolios are designed to meet that same requirement. Each GEO portfolio includes diverse technologies in order to avoid "putting all eggs in one basket".

The hazards of going to a 100 percent natural gas portfolio are numerous. Natural gas has a high level of price volatility, and when the fuel price shoots up, electricity prices are sure to follow soon. Residents of San Diego County have seen what happens when they put too much trust in natural gas. Natural gas also has other problems. It is a limited resource that is bound to become more difficult to obtain over time. It is also a fossil fuel that emits or creates many tons of pollutants annually, including lung-clogging particulates, nitrous oxides, corrosive ozone, as well as carbon dioxide and methane that are destabilizing the global climate.

The GEO portfolios are designed to meet all of these challenges, to cut pollutants dramatically, reduce reliance on fossil fuel, and serve as a hedge strategy against future price swings in natural gas. The GEOs provide three levels of capacity replacement relative to the current 700 megawatt power plants. The nominal capacity of the GEO options range between 500 megawatts and 970 megawatts, but this translates into a smaller equivalent capacity for the purposes of replacing the existing plant. This is because some renewable technologies, mainly wind power, only produce electricity part of the time. But the wind resource is given a boost relative to its otherwise intermittent nature, since one portion of the wind power is delivered to pump water uphill into a reservoir during the evening so it is available the next day to power generators when demand for electricity is high. Nearly all the rest of the portfolio's generation capacity is considered to be able to carry its weight in electrical system support, without any greater degree of help than other types of electrical generation routinely receive. This rating, called the Effective Load Carrying Capacity, is a product of the full capacity of the power generation equipment and the availability of the energy resource. In the case of wind, studies have shown that the *lowest* "carrying capacity" for actual major California wind farms is about 25 percent. We have been even more conservative, and assumed that only 20 percent would "count".

To confuse matters somewhat, yet another measure of reliable capacity is used by the state grid operator, the California ISO. This measure is exceedingly restrictive and actually has never established satisfactory rules for renewables like wind and solar power. With the increased legal mandate for renewable energy in the state, such rules will become increasingly necessary, and the ISO will not be able to ignore the contribution of renewables to the state's electric grid reliability, as they have in the past. This issue is not academic. During the 2000 to 2001 California "Energy Crisis", many commercial vendors of electricity took their conventional generators off-line. This caused serious problems that threatened grid stability, and resulted in greatly increased prices for their product. While these and other rather overt manipulations were going on, California's renewable generators continued to operate and they helped significantly to maintain the state's electric grid, and even to avoid blackouts. Thus, there is historical evidence, as well as ongoing demonstrated performance, to show how wind and solar power contribute greatly to the reliability of California's energy supply.

We established the size of the three green energy portfolios to meet 50%, 70% and 90% of the current South Bay Power Plant's capacity for supplying power during the hours of peak demand. Thus the portfolios are designed to meet the same needs and have similar functionality to the existing plant, though with a number of extended capabilities that the current plant does not have. For instance, the pumped storage plant can respond nearly instantly to changes in demand for electricity, a factor that can be critical during a power emergency. Other features will be described in this report. This report also shows how any capacity shortfalls can be replaced in other ways without resorting to adding new transmission lines leading out of the region.

A Range of Options

The GEO options contain a variety of portfolio elements, design sizes, and potential for siting of energy facilities, that allows for flexibility to meet different system needs and market conditions. There is really very little that is constrained about this portfolio, and in fact the GEO options show general strategies, as well as how to apply these strategies in very specific and practical ways. It is certainly possible to change these elements to respond to changes in the cost of renewables and of conventional power sources. Thus there is an adaptability that is completely lacking in the current plan to build another power plant on the same site as the existing power plant.

90% Replacement Option

Facility	MW	Est. Annual GWh
Wind Farm	400	1200
Pumped Water Storage Facility	150	420
Concentrating Solar Thermal Peaker with Natural Gas Backup	160	450
Natural Gas Peaker	220	620
Photovoltaics	20	30
Peak Demand Reduction	20	35
Transmission	----	----

RMR Replacement Target: 630 MW

Electricity Generation: 2220 GWh/year

Portfolio Average Peak Power Cost: 8.4-10.3 cents/kwh

70% Replacement Option

Facility	MW	Est. Annual GWh
Wind Farm	325	990
Pumped Water Storage Facility	90	250
Solar Thermal Concentrator Plant Powering a Peaker Plant with 30% Natural Gas Backup	160	450
Natural Gas Peaker	190	530
Photovoltaics	20	30
Peak Demand Reduction	20	35
Transmission	----	----

RMR Replacement Target: 490 MW

Electricity Generation: 1960 GWh/year

Portfolio Average Peak Power Cost: 8.3-10.4 cents/kwh

50% Replacement Option

Facility	MW	Est. Annual GWh
Wind Farm	150	460
Pumped Water Storage Facility	60	170
Solar Thermal Concentrator Plant Powering a Peaker Plant with 30% Natural Gas Backup	160	450
Natural Gas Peaker	90	250
Photovoltaics	20	30
Peak Demand Reduction	20	35
Transmission	----	----

RMR Replacement Target: 350 MW

Electricity Generation: 1170 GWh/year

Portfolio Average Peak Power Cost: 8.6-10.0 cents/kwh

Findings

The Green Energy Options (GEO) portfolios presented in this alternative energy plan are economically sound. The low-interest municipal bonds available to cities like Chula Vista can achieve significantly lower financing costs for renewable generation. Also, the largely fixed cost of the renewable GEO portfolios provides a hedge against substantial risk of increasing natural gas prices over the next 20 to 30 years.

The GEO Portfolios offer a number of benefits over a future commitment to a 100% natural gas-fired plant on the bay front. One benefit is cleaner air – the GEO portfolios would result in 60-80% lower emissions of particulate pollution and carbon dioxide every year when compared to a new "all natural gas" plant. Pursuing the GEO options would also get us firmly down the road of a more secure and sustainable energy future: they would produce more local jobs, decrease the region's over-reliance on natural gas, and keep more money in the local economy.

Community Choice Aggregation (CCA) is the best approach to eliminating the need for power generation on the South Bay. CCA would enable a full range of options, including transmission of power. If Chula Vista forms a CCA or builds a power generation facility, it may elect to obtain transmission services within or outside Chula Vista, by acquiring access to existing transmission capacity, arranging with SDG&E to provide transmission access, pursuant to Federal Energy Regulatory Commission (FERC) Order 888, or arranging to purchase transmission services from another party such as a tribal government. No option would require adding transmission lines leading outside the county, and all would make use of existing transmission pathways.

This Plan finds that the initiative would be best led by Chula Vista. Over the past four years, the City of Chula Vista has prepared extensively for the implementation of Community Choice Aggregation ("CCA") and/or development of a power generation facility. CCA would allow Chula Vista to find an alternative electricity supplier to SDG&E, and to decide what kinds of electricity to purchase. In addition, Chula Vista and a number of potential public partners may issue municipal revenue bonds ("H Bonds") to finance renewable energy and conservation facilities. These mechanisms are analyzed in this Plan.

The GEO Plan shows how CCA in conjunction with H Bonds can be used to develop a cost-effective, cleaner and more sustainable replacement of the South Bay Power Plant ("SBPP").

This report identifies several specific opportunities available to Chula Vista, allowing a variety of locally feasible technologies and partnerships. However, even if CCA is not pursued by Chula Vista, other governance structures and initiative options are available for the City to pursue some or all of the green energy options outlined in this report. Financial analysis of the energy options has been performed with this in mind, to demonstrate the cost of electricity by considering the portfolios as independent investments.

A critical facet of the GEO options is to include local power resources that require little or no transmission facilities to deliver the power to customers. Chula Vista and the San Diego County region offer opportunities to develop a variety of green energy resources. These opportunities include solar energy, energy conservation, and cogeneration, in coordination with parties interested in participating in the development of the facilities and/or the purchase of power from such facilities. Where transmission of electricity is required, the GEO options have sought to insure that existing transmission corridors can be used, to avoid most of the expense and environmental impact of any new facilities. The GEO options are also designed to reduce the need for importing renewable power, and natural gas, from outside the county.

These proposals are more local in nature than the renewable power supply now being proposed by SDG&E for residents and businesses in its service territory. The options presented are financially feasible at competitive wholesale and retail prices, with either a CCA or a city-owned merchant facility, or both, being the structuring principle of the project.

Photovoltaics (PV) on Chula Vista rooftops, energy efficiency, demand response may be fundable with existing ratepayer revenue if a CCA is formed and would be facilitated by submitting a request to administer the funds to the California Public Utilities Commission.

Other distributed generation may be undertaken within the City under a CCA or a revenue bond funded ("H Bond") program, and Chula Vista may invest General Funds in renewable energy projects for non-CCA customers if the City wishes to operate the plant as a public enterprise. Because a range of project sizes may be necessary to eliminate or meet hundreds of megawatts of regional demand in order for the Independent System Operator (CAISO) to accept a downscaling of new power generation on the South Bay site, this report identifies several physically viable, legally developable and economically competitive green power facilities, estimates facility costs, schedules for payback and power pricing. The range of facility scales in each Scenario are also based on a variety of potential market and financing structures, including Community Choice Aggregation (CCA) the use of H Bonds, rebates for photovoltaics under the California Solar Initiative, and state funding for energy efficiency programs pursuant to the Community Choice law, AB117.

This report finds that a significant level of public sector investment is essential to replace any potential need for power at the South Bay site. The ability to eliminate or reduce the need for power generation at the South Bay Power Plant site depends on the municipality's degree of public investment, as well as investment by potential strategic partners in the region. This investment may be structured as a municipal enterprise using municipal bonds, and/or as a CCA to add even larger-scale private sector purchasing power to public financing.

This report finds that a Chula Vista investment in renewable energy and conservation facilities involves a lower degree of municipal risk than investment in a 100% natural gas generation power plant, because of reduced exposure to the highly volatile price of natural gas. Fuel usually constitutes from 50% to 80% of the life cycle cost of a natural gas-fired power plant. This Plan identifies benefits from the GEO portfolios, including:

- Profits realized from renewable energy or conservation facilities, could benefit taxpayers by contributing funds to the City of Chula Vista General Fund
- Should the City initiate a Community Choice Aggregation (CCA) the portfolios can be used as insurance to protect the ratepayers from escalating electricity prices

- Renewable and conservation facility assets will retain their market value and generate revenue after H Bonds or other financing are repaid, in some cases for decades, offering both returns on public investment and very low cost energy for local government, residents and businesses.

This Plan finds that the GEO Portfolios are consistent with existing local, state and federal policy, regulations and law, and meet the stated project objectives in the AFC for the South Bay Replacement Project:

- Commercially viable and capable of supplying economical electrical services – capacity, reliability, ancillary services, and energy supply – to the San Diego Region.
- Capable of ensuring the timely removal of the existing South Bay Power Plant and that fulfills the obligation found in Article 7.1.a of the Cooperation agreement, which states, "use commercially reasonable efforts to develop, finance, construct and place into commercial operation a new generation plant replacing the South Bay Power Plant...which shall have a generating capability at lease (sic) sufficient to cause the ISO to terminate (or fail to renew) the must run designation application to the South Bay Power Plant on or before termination of the lease" and upon which the size of replacement power is based.
- Meets applicable laws, ordinances, regulations, and standard (LORS) of the California energy Commission, Chula Vista, the Unified Port of San Diego and other agencies, and complies with the Applicant's Environmental Policy
- Consistent with the objects, guidelines and timing goals of the emerging Bay Front Master Plan.
- Assists in maintaining and/or increasing the regional electrical systems' efficiency and reliability.
- Supports implementation of the state-mandated 20 percent Renewable Portfolio Standard (RPS) requirements for renewable energy.

Recommendations

- Chula Vista should present evidence to the ISO and other regulatory bodies, proving why a replacement for the current plant is not needed on the Bayfront. ***This report shows that nearly 2000 megawatts of alternative options exist within San Diego County***, some of which would cost far less than replacement of the South Bay Power Plant at its current site. In some cases merely changing regulatory status or evaluation of existing or planned resources, or the need for them, is all that is required. It is exceedingly unlikely that replacement of more than a fraction of the current plant is really necessary to meet the needs of the region for years into the future. That is the most important reason why a range between 50% and 90% replacement of existing capacity has been proposed in this report.

- Chula Vista should further investigate the options identified in this report to begin discussions with potential site owners, financing sources and partners for different projects. In other words, scoping needs to move to the next level of specificity to answer critical questions.

- Chula Vista should fund and prepare an Implementation Plan and draft a Request for Proposals for Community Choice Aggregation and H Bonds that includes designing, building, operating and maintaining a solar concentrator, wind and pumped storage facility in conjunction with local solar photovoltaics, distributed generation, energy efficiency and conservation. These measures should be supplemented with natural gas fired co-generation to balance out the portfolio risk and energy costs, as well as to insure the full reliability requirements are met.

- Chula Vista should only entertain sites for facilities that minimize the need for new transmission, and only allow transmission that is placed on existing rights of way. Any new lines should be occupied only by clean energy capacity. No major power lines on new corridors are needed, as they will impose billions of dollars in costs on ratepayers as well as make the region even more dependent upon energy imports. These imports send dollars and jobs out of the region while new transmission corridors would spoil the county's landscape and natural beauty.

- Chula Vista should participate in the ISO RMR designation to ensure the RMR is calculated appropriately to include all renewable and other green energy sources.

- Chula Vista should participate actively at the California Energy Commission, Independent System Operator (CAISO), California Public Utilities Commission, and Federal Energy Regulatory Commission to propose the options identified in the GEO as preferable to repowering the South Bay Power Plant site.

- At present two of the largest generating plants in the region, representing about 1000 megawatts of capacity, contribute nothing to grid reliability, according to ISO evaluation.

San Onofre Nuclear Generating Station (SONGS) is not counted at all toward regional generation, even though it supplies over 400 megawatts of power, 24 hours a day, to San Diego County. That is because it uses up capacity on the same transmission line that is used for importing electricity. And the new Palomar plant, at over 500 megawatts, is uncounted due to a mere technicality. Chula Vista should urge the ISO, CEC and CPUC to move forward with assuring that the Palomar power plant is fully accounted for as reliable generation capacity, and that a short transmission line be added to the existing South of SONGS (SOS) corridor to connect the plant directly to the regional grid without casting a transmission shadow for electricity imports from the north. These two tasks would together supply approximately 500 megawatts of additional reliable capacity to the region for by far the least cost and environmental impact.

- Chula Vista should challenge the "bait and switch" tactic of justifying a new 24-hour a day "all natural gas" powered base-load replacement plant on the bay, based upon the ISO reliability contract on the existing plant. The current plant is considered necessary for meeting peak demand when power is urgently needed for grid stability, and only runs its generators part-time. The function of the current plant is completely different from the one proposed to replace it, and should require a separate evaluation of need.

- Chula Vista and other local and regional land use authorities should adopt stringent building standards that maximize energy efficiency, demand response, and development of clean, renewable energy sources integral to new and renovated building construction.

2. Introduction

The Green Energy Options (GEO) alternative energy plan has been developed by Local Power for Environmental Health Coalition (EHC) to be considered by the City of Chula Vista and other governmental entities in the San Diego County region. The Plan identifies and analyzes local opportunities for more sustainable, secure energy development in San Diego County in order to reduce the need for, or the scale of, a natural gas generation facility to replace the South Bay Power Plant (SBPP).

The GEO will include appropriately scaled renewable generation, energy storage, and energy efficiency measures. More broadly, the GEO will develop opportunities for Chula Vista to act singly, as well as inter-governmental or regional opportunities to eliminate the need for any power plant at the SBPP site, and to reduce the region's need for another large gas-fired power plant. These options will support reliability of San Diego County's regional electric transmission grid, which is run by the California Independent System Operator.

This report presents a series of scenarios, location- and time-specific opportunities that are supported under current California and federal law, for Chula Vista to negotiate with energy suppliers, undertake public works projects, and administer energy efficiency programs to reduce or eliminate the need for a power plant at the South Bay Power Plant site. Every scenario and proposal outlined in this report can provide opportunities for the City of Chula Vista to operate a profitable energy facility and/or provide residents, businesses and agencies with competitively priced energy services.

The profit structure will depend upon how the projects are financed, and implemented. For example, *the lower cost of capital for bond-financed wind farm or natural gas peaking plant essentially locks in a long term price advantage over any private or utility competitor.* The fact that renewables are now being required by law for all utilities and Community Choice Aggregators means that there is a built in market for the foreseeable future. The target requirement for purchasing renewable energy grows each year. Twenty percent of all utility company electric supply must by "green" by 2010. After that year a new target is likely to be set at 33 percent, a level that is fully supported by the governor and all the regulatory bodies. Legislation has been introduced that would write this higher goal into state law, and mandate that it be achieved by 2020. Utility companies have complained that it has been difficult to access sufficient renewable supplies; thus a growing market is wide open to those who can successfully develop green energy projects.

Municipalities are in a unique position to benefit from this arrangement. Renewables face certain hurdles that municipalities hold the power to overcome. The first hurdle is financing. Private developers are faced with the challenge of raising capital for projects with certain risks. For example, wind projects may be eligible for special tax credits, but only if they are built by certain dates. If those dates pass, because of delay for any reason, then the project loses its financial viability. Municipal governments do not receive tax credits, and thus are not bound by such considerations. Their low cost, tax free bonds provide superior benefit to the tax credit, and is available to them at all times without being subjected to the risk of federal tax policies over which they have no control.

A second financing risk is associated with finding a long term buyer for the electricity. While renewable standards do provide some assurance, lenders want to see contracts running out into the future as far as 10 to 20 years. This can be quite difficult to achieve. Municipalities that form Community Choice Aggregations (CCAs) have a built in market integration that no private developer could ever have, in that a CCA is both a seller and buyer of electricity. The market risk is thus greatly reduced, since the CCA can agree to purchase some or all of the electricity provided from its own renewable plant for up to 20 years into the future. This lowers borrowing cost, a critical component for making renewables cost effective or profitable.

The fact that renewables greatly reduce reliance upon fuel means that once the capital expense is paid off, the cost of generating electricity is reduced to relatively small operating expenses. Electricity sold at full price from these facilities, after the financing cycle, will likely realize higher prices on the market at the same time that ongoing costs are greatly reduced. In this sense, renewables are an investment in the future. Renewables can also provide more near term benefit, as valuable insurance against spikes in fuel prices, protection against liability for— and damage from—pollution, and the possibility to benefit from carbon markets under California's new greenhouse gas reduction law.

This GEO plan presents three South Bay Power Plant replacement scenarios with portfolios that contain mixes of wind with pumped storage, solar concentrators with gas backup, as well as photovoltaics and natural gas cogeneration. The GEO can be combined with conventional electrical capacity from available wholesale markets.

Facilities are modeled according to two basic criteria: they would generate power at prices competitive with wholesale market power prices, and could provide this power within the portfolio of electric service under a Community Choice Aggregation. Thus, the GEO presents these investments in an apples-to-apples comparison with both wholesale peak and base load power prices, and reflects potential changes in natural gas and electric generation prices in SDG&E's rates, which are subject to change every six months.[2] The purpose of this modeling is to provide real, buildable, financable, and feasible investments that can eliminate the need of the Independent System Operator for the South Bay Power Plant, and can also be sound public investments in green power generation and conservation facilities.

The investments are also described in a suitable manner for a CCA to incorporate these assets in a larger portfolio to supply its full electric power needs and compare this to SDG&E retail rates. This GEO may be adopted by the City of Chula Vista, and may be followed by drafting and adoption of a CCA Implementation Plan and Request for Proposals to solicit bids from suppliers, who will conduct a full CCA portfolio analysis and enter into a contract to build facilities and provide power service to participating communities. What this report does establish is that investments in a diverse set of peak power assets could benefit Chula Vista and surrounding communities over a 30 year expected equipment lifecycle, especially in the context of a CCA, and secondarily in the context of a municipally financed, locally developed green power facility.

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[2] This document contains forward looking projections about the prices of commodities and infrastructure; Local Power in no way warrants or guarantees, or will in any way be held liable for, such investments. All investments carry risks, and it is the responsibility of those who make such investments to verify all claims, and assume all associated risks, express or implied.

If implemented, any one of the proposed scenarios would form a landmark achievement following a decade of growing leadership in energy independence and entrepreneurial sustainability in Chula Vista. It would also be a positive, substantial contribution toward international efforts to reverse the Climate Crisis.

The Proposed South Bay Replacement Project

The existing South Bay Power Plant, over 40 years old, is outdated, inefficient to run, and has significant adverse water and air quality impacts. There is little disagreement that the existing plant needs to be shut down. The plant has materially damaged the South San Diego Bay ecosystem and creates significant air pollution. The power company LS Power, all of whose merchant power plants (including the South Bay Power Plant) were recently acquired by Houston-based Dynegy[3], is in the permitting process for a South Bay Replacement Project (SBRP) which includes the demolition of the current South Bay Power Plant and the construction of a new gas-fired power plant near the current site. The SBRP is proposed as a 620 MW net combined cycle generating facility using two natural-gas-fired combustion turbine generators and one steam turbine to be cooled with air cooling.

The proposed South Bay Replacement Project would not use Bay water for cooling, which represents a significant environmental improvement. The SBRP would, however, still create a substantial air pollution hazard for neighboring residents. Like the existing plant, the proposed replacement plant would be directly upwind of residents and schools, and would perpetuate degraded air quality for west Chula Vista residents. The west Chula Vista zip code registers childhood hospitalization rates for asthma that are 20% higher than the overall county rate in 2003.[4] The SBRP is being promoted as a plant that will reduce air pollution impacts. Although more energy is expected to be generated for the pollution produced, total pollution impacts to the densely populated low-income neighborhood that is immediately downwind of its smokestacks are not expected to be appreciably reduced, and in fact may even increase. Though a new plant would be more efficient, it is planned to run far more often and burn more fuel, and so could produce comparable if not greater total pollution. The California Energy Commission and the SBRP project proponents have not yet come to an agreement on the estimated pollution impacts from the proposed project. We estimate that total particulate matter pollution could increase from about 73 tons per year to about 94 tons per year when comparing the existing South Bay Power Plant to the proposed replacement plant (Appendix H). The LS/Dynegy project offers *no* mitigation or additional offsets for impacts to air quality, and claims that particulates will remain the same as the current plant without giving adequate information to back up this claim.

The existing South Bay Power Plant is a significant contributor to greenhouse gases, large enough on its own to have a significant climate impact (approximately 1/10,000th of global greenhouse gas emissions). The proposed new gas-fired replacement plant would continue to contribute significantly to the global climate crisis, when excellent local solar and wind

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[3] On September 15, 2006, Independent Power Producer Dynegy announced it has agreed to pay more than $2B in stock and cash for the merchant plant portfolio of private equity fund LS power Group, including SBPP and eight other power plants acquired from Duke Energy for $1.6B in May. LS Power Group will retain a 40 percent stake in the combined company. Dynegy's management team, including CEO Bruce Williamson, will run the company.

[4] California Office of State Planning and Development, 2003 Public Patient Discharge Data; 2000 Census.

conditions are available for renewable generation of electricity, as this Plan has surveyed, analyzed, and modeled.

The important question at hand is how the energy capacity provided by the existing plant will be provided. This decision will shape the region's energy future and the health of Chula Vista residents for decades to come. The current replacement proposal does not adequately assess viable alternatives for the power plant design, as required by US and California state law, nor has there been adequate assessment of the ability for other already permitted and proposed plants in the region to meet the goals of the project.

Meeting the Appropriate Energy Needs

Any replacement of the plant with renewable resources must address regional power needs. The scenarios for Chula Vista in this report will present model solutions on a graduated scale to ensure that regional transmission grid requirements of the California Independent System Operator (ISO), the non profit agency charged with maintaining transmission grid stability, would be met in each proposed scenario.

The Green Energy Options portfolios presented here are designed to meet the energy service provided by the existing South Bay Power Plant. The California Independent System Operator's (ISO) designation of the South Bay Power Plant as "Reliability Must Run" ("RMR") requires that it provide peak energy production to ensure regional electric system reliability. SDG&E has built – and is still building – new power plants and transmission lines connected to the regional grid. As a result, the ISO's designation of need for power generation from the South Bay Power Plant is changing. This report presents three portfolios that would replace 50%, 70% and 90% of the existing 700 megawatt capacity of the 2006 RMR contracts on the plant. (the 2007 RMR contract is lower, at 515 MW). The portfolios are designed to meet a range of possible RMR demands so that changing ISO requirements can be met with little or no adjustment to the portfolios.

The Reliability-Must-Run (RMR) role that the South Bay Power Plant serves is related to the plant's capacity, or the most that the plant can produce at a given instant, measured in megawatts (MWs). The plant's electricity service can also be thought of in terms of how much electricity capacity it provides to the grid over a period of time. This is measured in Megawatt Hours (MWh). The South Bay Power Plant currently runs essentially as a load-following plant that ramps up output at times of highest demand in the afternoon and evening, and a large portion of the plants capacity is rarely used. This is further explained in the next section of this report.

On a capacity basis, 700 megawatts of the South Bay Power Plant are under contract with the ISO for 2006 (515 megawatts for 2007). On a megawatt-hour electric generation basis, the current plant produces about 1.9 million Megawatt-hours per year.[5] Notably, the proposed South Bay Replacement Plant would only provide 120 megawatts of added peak energy, far less than the current plant or the GEO options do.

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[5] LS Power. Application for Certification to the California Energy Commission for the South Bay Replacement Project. Pg 6-2

3. ISO Reliability Must Run (RMR) Criteria Analysis & Scale of Replacement Energy Needs

Other than a much cleaner and more sustainable power source and competitive pricing, the other main criteria for the scenarios in this report are that each must conform to the ISO's Reliability-Must-Run ("RMR") designation of the current South Bay Power Plant (SBPP), and that any replacement portfolio must fulfill the current function of the plant, which is to provide power during the peak hours of the day.

There are a number of variables that will impact the final ISO designation for the site, including adjustments in predicted regional demand and other regional generation assets. These can change significantly from year to year, and it is not uncommon for projected requirements to be revised downward to lower levels. For 2007, the ISO will seek contracts on only three of the four units at the South Bay Power Plant.[6] This will result in a reduction to 515 MW under RMR contract.[7]

In the recent past, opinions on the need for replacement power on the Bayfront have run the gamut from nothing more than a substation to maintain grid stability, to massive power plants upwards of 1200 MW. As utility forecasts often change, or may be manipulated, Chula Vista should evaluate a range of options to fulfill the energy needs required to replace the existing SBPP. Chula Vista would be free to pursue any of the scenarios described in this report with projects that range from 10 Megawatts of local photovoltaics to a 400 MW wind farm. First we will examine factors related to the current scale and use of the South Bay Power Plant, and then discuss several variables in play that should be addressed prior to establishing the real size of the RMR deficiency, if any, that is needed to be filled by a replacement plant.

Capacity factor is the normal way in which degree of plant utilization is measured. This is expressed with a percentage, which is calculated by taking the number of megawatt-hours generated over a year divided by the total number of megawatt-hours the plant could generate *if it operated full time at full capacity*. Because "capacity factor" is a compound of total capacity and hours of operation, the concept creates some ambiguity. For example, a power plant operating at a fifty percent (50%) capacity factor could mean that it is running at half its rated capacity all of the time, or it could mean that the plant operates at full capacity half of the time. Or, it could mean any varying level of operation between these two extremes that created the same mathematical result.

The operation of RMR facilities is complex, as they may run at various levels at different times of the day and year. Then they may be suddenly asked in the summer, when other resources are strained, to ramp up to full capacity for just a few hours.

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[6] Motion: 2006-09-G1 Decision on Local Area Reliability Services Requirements for 2007

[7] California Independent System Operator. Local Area Reliability Service 2007, Report of Gary DeShazo, August 31, 2006.

Current Scale and use of the South Bay Power Plant

Any replacement facility or facilities will have to fill the specific role served by the existing South Bay Power Plant. This plant is composed of four main generator units that together are considered to have 690 megawatts of dependable capacity. The following table shows some basic facts about the generating units at the South Bay Plant:

Table 1. Operating Profile of the existing South Bay Power Plant.

Unit	Built	Dependable Capacity (MW)	Output per Year (MWh)	Capacity Factor	Fuel Use (MMBtu)	Heat Rate (Btu/kwh)
1	1960	147	459,135	0.357	4,654,5 31	10,138
2	1962	150	466,098	0.355	4,400,057	9,440
3	1964	171	319,847	0.214	3,312,646	10,357
4	1971	222	84,940	0.044	1,023,633	12,051
Total		**690**	**1,330,020**	**0.220** [8]	**13,390,867**	**10,068**

Source: Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements. California Energy Commission, Aug. 13, 2004, 100-04-005D.

In addition, there is a 16 megawatt combustion turbine, bringing the total capacity to 706 megawatts. The 2005 RMR evaluation by SDG&E rates the units a little differently and comes to a total of 689 megawatts for the four larger units, which would lower the plant total to 705 megawatts. In general, power plants as they age lose a small amount of rated capacity. For the sake of this report we assume a rounded total of 700 megawatts for the rated size of the power plant in 2009. The actual capacity requiring replacement is likely to be significantly less, and by a much larger factor than this marginal adjustment, for reasons described in this report.

Since the South Bay Power Plant is old and inefficient, it is not desirable to have it running most of the time. This is mainly because it consumes more fuel than competing plants, and thus cannot recoup its fuel and other costs unless the price for electricity is high. High prices occur during the peak hours of the day, when other expensive power sources are also brought on line.

The actual cost of running the plant is a function of the cost of natural gas fuel, the efficiency of the generators, and the fraction of the time the plant is running. The less the plant runs, the more expensive the electricity is. The fuel cost for natural gas is given in dollars per million British Thermal Units (MMBtu), which is a standard measure of energy content. It is the energy in very close to 1000 cubic feet of natural gas. Prices for natural gas on the New York Mercantile Exchanges (NYMEX) are around $7.00 per MMBTU for near term futures contracts. This is

[8] The SBRP AFC before the California Energy Commission lists the current capacity rating as 30%.

triple the prevailing cost of natural gas during the 1990s, but considerably lower than the historical highs following hurricane Katrina in 2005.

Higher natural gas prices have a dramatic effect on the cost of generating electricity, particularly for aging facilities like the South Bay Power Plant. The following table estimates how much it costs to generate electricity from the four South Bay Power Plant units at different prices for natural gas. The lowest price, of $6 per million BTU (about 1000 cubic feet) is on the low to mid range for recent prices of natural gas for electric generators, while $8/ million Btu is near to the average projected price for natural gas by the US Dept. of Energy for the period until 2030. Most analysts expect a long term trend of increasing natural gas prices, and the DOE projects a nominal price of $11.74/million Btu in the year 2030, which is reflected by the upper range in the table below. Because the financial life of an electric generator built over the next few years will continue in operation well beyond 2030, it is very likely that even higher prices will be seen during that period. Note that a new power plant could have *even higher costs*, because the increased efficiency would be more than offset by the increased capital cost:

Table 2. Approximate cost of generating electricity (in nominal cents/kilowatt-hour) with the South Bay Power Plant and with a new gas-fired replacement peaker plant.

Unit	Heat Rate (Btu/kwh)	Capacity Factor				
		Natural Gas price (per mmbtu)	**$6.00**	**$8.00**	**$10.00**	**$12.00**
1	10,138	0.357	7.8	9.8	11.8	13.8
2	9,440	0.355	7.4	9.2	11.1	13.0
3	10,357	0.214	9.0	11.1	13.2	15.2
4	12,051	0.044	20.9	23.3	25.7	28.1
Total SBPP	**10,068**	**0.220**	**8.8**	**10.8**	**12.8**	**14.8**
Modern equivalent	**9,400**[1]	**.220**	**11.9**	**13.8**	**15.7**	**17.6**

Source: California Energy Commission

The capacity factor for the current four generators ranges between 4.4% and 35.7%. In general, we have chosen to assume a 32% operating capacity for the GEO options for a variety of reasons. It falls within a feasible range of performance of renewable facilities; it allows a common baseline of comparison for economic purposes; and it allows financial targets to be met. It may turn out, however, that the optimal capacity factor for any future plant may differ from what we have assumed. The plant owner and operator should evaluate market conditions, such as the value of peak power and the price of natural gas. It may also be advantageous in some cases to sell power outside of the peak period for supplemental income. The wind plant is specifically designed in this manner in that it is oversized compared to the needs of the pumped storage. This will allow for additional electricity sales that offset higher cost peaking resources. Similarly, the natural gas plant might be operated at a higher capacity factor to serve reliability needs of the wind plant during hours when its peaking service is not required. This would supply additional revenue that could offset the natural gas plant costs or improve the value of the wind plant by providing firm electric generation.

Current RMR Contract with the ISO

Until 2006, the full South Bay Power Plant was bound by a contract with the California ISO, the agency responsible for the operation of the state's electric grid. This contract, called a Reliability Must Run (RMR) agreement, requires the plant to remain available up to its full capacity in order to assure the reliability of the electric system in the San Diego County Region. However, in January 2007, it was reduced by 174 MW to 515 MW, with the releasing of unit #3 from this obligation. RMR contracts are effective for one year, and the contract on unit #3 could potentially be reinstated in 2008 if the ISO and plant operator agree.

The RMR contact is particularly designed to assure that power plants are available during times of high demand, when other grid facilities, including generators and transmission lines, are being fully utilized and need extra support. The full power of all four generator units is rarely needed for actual operation, but they all must be on call if needed. This is particularly true of generator number four, the largest and least efficient of the units, which only operates a small fraction of the time.

Variables that Influence RMR Calculations and Designations

There are a number of variables that influence RMR designations. These must be accurately evaluated to establish the real size of the RMR requirement.

Peak Demand and Types of Power Plants

During the course of a day, electric power consumption reaches a low level around 3 to 4 o'clock in the morning. Then demand rises like a great wave during the day until a peak demand occurs, any time between noon and early evening. After the peak, the daily power demand wave ebbs and then returns to its lowest level again early the next morning. This is a "typical" daily pattern, though there is significant variation in different locations, on different days of the week and in different seasons of the year.

It is the responsibility of the electric generators, state regulators, and the business enterprise that purchases power for customers, to ensure that the available electricity on the grid always meets or exceeds the demand. This is critical, since even a small shortfall in generation can cause disruptions of service ranging from poor quality power, to rolling blackouts, or complete collapse of the grid.

In response to this daily wave of demand for electricity, power plants are differentiated into three main functional types. A generator is used most efficiently, and is cheapest to operate, if it is run 24 hours a day at a steady rate. Those that run 24/7 are called base-load plants.

A second type of power plant increases and decreases its level generation of electricity to follow up and down the daily demand wave. These are referred to as load-following plants. Because they are less efficient, the electricity from these plants is often more expensive than the electricity from a base-load plant.

The third type of plant is only turned on for short periods when the power needs spike upward, and cannot be met by the base-load or load-following plants. These are called 'peaker plants'. Since this is the least efficient way to use a power plant, this is the most expensive source of electricity. Due to its extreme age and inefficiency, the South Bay Power Plant has been essentially changed over time from a base-load to a peaking facility. However there is considerable difference in the degree to which the four generator units are used.

Firming up the Capacity of Renewable Generation

Some renewable energy sources, such as wind and solar power, generate varying amounts of electricity on their own schedule rather than in accordance with the needs of the electric grid. For example, wind turbines in California tend to be most productive in the summer evenings when the coastal winds pick up. This is usually after the time when solar energy facilities have dropped out, but demand from residential customers is high. Yet, the wind often continues into the night, long after the demand has fallen and thus does not fully match the peak needs for electricity.

On the other hand, solar energy facilities typically are producing during peak hours in the middle of the day. Flat plate, stationary photovoltaic modules pointing south and angled toward the mid-summer sun will begin producing small amounts of electricity early in the morning, peak in production around noon, and gradually decrease in output over the afternoon. Thus there will be no solar power available to meet the high evening demand that often lasts to 10 or 11 pm.

On top of the above problems, individual solar energy systems can be interrupted when, for example, the sun is behind a tree or a cloud passes overhead. Low winds can cause a wind plant to produce little or no power, while short gusts can cause sudden spikes in output that cannot be absorbed by the grid.

The three significant technical shortcomings to renewable electricity sources such as wind and solar energy are:

- The production of electricity cannot easily be increased or decreased in response to electricity demand.
- The resources are subject to short term, unpredictable fluctuations that may be difficult to integrate into the grid.
- Natural cycles do not necessarily match the exact time, or full duration, when added power is needed.

There are means to address all of these problems and “firm up” the supply of power. Renewable generation facilities and other support systems can be joined together in a variety of ways to cancel each other’s idiosyncratic production patterns, and to supply power when it is needed:

- Geographic separation. Spreading out generation units, such as wind turbines, over a wide geographic area helps greatly to regulate the combined output, since it is very unlikely that the wind will suddenly dip or spike in all locations at the same instant. In the same way, if solar energy systems are widely dispersed, there is little likelihood that a small cloud will cover them all at the same time.

- Integration of intermittent generators. This involves using different types of renewable generation, such as solar and wind, together in a way that provides a more robust service. The sun allows for production during the day, while wind picks up in the evening.
- Integration with conventional generation. A common practice is to back up the solar or wind power with existing sources of power from the grid. This usually comes from a peaking or load-following gas fired power plant that is coordinated to the measured output of a wind or solar facility. In other cases, the gas generator may be built together with the renewable facility, and share the same transmission wires. This maximizes utilization of the power line, and can avoid the surcharges that are often levied against wind plants that need to reserve more line capacity than they can reliably use. An even better source for back up of renewables that produce intermittently is hydroelectricity, which has the extraordinary capacity of being able to respond almost immediately to changes in the electric system. It can use this ability to enhance the efficiency of wind farms.
- Integration with power storage systems. Power storage, such as batteries or flywheels, can absorb extra power from a wind or solar facility, and release it at times when the power is most needed. This allows the solar and wind generators to be fully "dispatchable", meaning that they can be tapped when they are needed most. Batteries and flywheels are useful for relatively modest power needs, for a single building or for very short periods of time on a larger scale. Much larger amounts of power can be stored by using the renewable generation to pump large quantities of water from a lower to an upper reservoir. When the power is most needed the water is allowed to flow downhill through a turbine powering an electric generator. This sort of technology has been used for many decades. Almost all conventional energy storage systems are efficient, but they can add significant cost.
- Integration with demand response and energy efficiency. Photovoltaic facilities are always better investments when combined with energy efficiency and conservation measures. A more advanced application is to use these tools in a coordinated way to provide reliability for the grid.

San Diego Regional Electricity Supply and Demand

San Diego County's electric system is essentially an island connected to the outside transmission system at two points. One of the transmission connections is in northwest San Diego County leading toward Orange County (WECC Path 44). Path 44 is the only connection into the rest of the California ISO system. The other transmission connection, the Southwest Power Link (SWPL), begins at the Miguel substation east of San Diego and heads through the east county, just north of the Mexican border, and then leads into the Imperial Valley. This 500 kilovolt line allows for power to be brought in from generator plants in Arizona. The total import capacity of the two transmission corridors is 2850 megawatts. The 2005 projected peak electricity generation requirement for SDG&E was 4370 megawatts, meaning that 65% of the summer peak demand could be met by electricity imported through the transmission wires alone.

The electric resource potential is defined by the generation resources inside the country and the import capacity at the two transmission entry points. ISO rules require that the regional grid be resilient to some degree against failure of system components; specifically the grid must have resources to withstand the removal of the largest generator and one transmission line. This is referred to as the "G-1/N-1" criteria.

These criteria require that all reliable resources be added up, and then the largest generator and one transmission line are subtracted. For this purpose the 350 megawatt capacity of the Southwest Power Link line is subtracted from 2850 megawatts of total transmission capacity to result in 2500 megawatts of capacity that is considered to meet the reliability criteria. The main generator resources are 945 megawatts of steam generators (of a total 971 MW) at the Encina Plant, 689 megawatts of steam generators (of 706 MW) at South Bay. In 2005, there were another 395 megawatts of capacity under RMR contracts, including the remaining capacity at Encina and South Bay that are gas turbines. This brings the total RMR generator capacity to 2030 megawatts. In San Diego County the largest generator for 2005 was the 329 megawatt unit at Encina, called Encina 5. The largest generator in the region contributes nothing to the reliability requirements except to serve as the discounted resource. Similarly, one transmission line is worth 350 megawatts of carrying capacity, and also gets subtracted from the total. The available resources are then compared with assumed projections about future peak demand, which is based upon a probabilistic model. The generators and transmission capacity are supposed to meet a spike in demand that has a 1 in 10 year probability of occurring. The following table shows in summary the region's 2005 resources as calculated by SDG&E.

Table 3. SDG&E 2005 RMR Resource Calculation

	Capacity (MW)	Cumulative Total (MW)
Peak Demand plus line losses	4370	4370
Transmission Import capability	-2850	1520
N-1 loss of one transmission line	350	1870
QF generation resources	-180	1690
Removal of largest generator (Encina 5)	329	2019
Designated RMR units	-2030	**-11**

While the above was valid for 2005, significant changes occurred in 2006. Specifically, the Palomar facility was brought online, making it the largest generator in the region; Encina 5 lost its designation as the subtracted generator. Since about 8.6% of the electricity produced by generators is lost in the transmission and distribution system, this loss must be added to the peak demand in order to figure out how much the generators need to produce. Thus, included in the 4370 megawatts is about 375 megawatts of power lost in the electric grid, mostly in the form of dissipated heat caused by the electrical resistance of power lines and transformers. This is important, because *the 8.6% loss is avoided whenever an energy resource is placed where the demand is located.* Partly for this reason, utility companies like to consider on-site generation, like photovoltaic systems on a customer's roof, as removed load rather than as generation; it makes the calculation of the power resource simpler for them.

When you take the total requirement to meet demand and subtract all available resources, then the result for 2005 was a negative 11 megawatts. This means that there was 11 megawatts more estimated electric system resource than was required to meet RMR criteria in that year. Retirement of the South Bay Power Plants' 700 megawatts in 2009 would have to be replaced with other resources in the form of new generation within the county, new transmission to bring power into the county, or peak demand reduction. These resources not only must replace South Bay, but they also must meet future growth in demand in the SDG&E territory. This requirement can be met in a number of ways *without any need to build new transmission capacity that goes out of the county.* In addition, at a meeting of the Energy Working Group representatives of ISO and of the Resources Subcommittee stated that there were several options to close any reliability gaps, and that building several smaller power plants would be a better option than a large base-load plant.[9]

Addition of New Power Plants

Two new power plants have been brought on-line since the resource calculations were made by SDG&E in 2005. A 44 megawatt peaking plant in Escondido (MMC) and the 546 megawatt plant at Palomar/Escondido built by Sempra. This adds a total of 590 megawatts to the region's power generation; nearly the anticipated replacement capacity for the South Bay plant. Since the Palomar plant is now the largest generator, the Encina 5 plant adds back its 329 MW.

Future Power Plant proposals

An additional 561 megawatts of capacity has been permitted and contracted at Otay Mesa, with an anticipated on-line date of January, 2008. This project has been postponed a number of times, leading to questions about when and if the power plant will be completed. Yet, if this power is brought on-line, as is expected since a long-term contract was signed with SDG&E, then there will be major implications regarding the South Bay Power Plant. So large is this addition that it will certainly reduce, and may even eliminate, the need for an SBPP replacement. A 22 megawatt biofuel plant has also been announced, bringing the total possible additions to 612 megawatts in the SDG&E system by the 2009 retirement date of the South Bay plant. A proposal by ENPEX for the Community Power Project could result in electric generation capacity located at the Sycamore Substation of 750-1500 MW, proposed to be operable by 2011.

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9 "Ms. Hunter asked whether options to close the gap were evaluated in the CAISO study. Mr. Shirmohammadi explained that there is a multitude of ways to address this issue but that large power plants were not the solution to the problem. Mr. Shirmohammadi stated that if building more power plants were the decided route, building several smaller one would be a better option." Minutes of SANDAG's Energy Working Group, July 27, 2006, p. 13

Local Targeted Upgrades in Transmission

The San Onofre Nuclear Generator Station (SONGS) has 2200 megawatts of capacity. The SONGS facility is jointly owned by San Diego Gas and Electric (SDG&E), Southern California Edison (SCE), and two municipal utilities. SDG&E's share is 20% of the power output, or 440 megawatts. Even though the nuclear plant is in San Diego County, it is not included in the resource base. This is because it relies on the northern transmission line (WECC Path 44) for moving its electricity into the rest of the county. Therefore it takes up transmission capacity and effectively removes 440 megawatts of power from being brought into the region from out of the county.

One option would be to add to the transmission system *within the county*, using existing rights of way, to bring the SONGS electricity far enough south into the regional grid so it does not block the northern imports. An additional factor to consider is the planned decrease in capacity of the nuclear plant. The past 440 megawatt share is expected by SDG&E to be reduced to 377 megawatts by the year 2009, and to 311 megawatts thereafter. This means that the actual capacity advantage of the new transmission line may be 311 megawatts in future years.

Energy Efficiency and Loading Order Requirements

New electric resource plans are required to follow the state's new concept of the "loading order." The loading order requires utility companies to make energy efficiency resources their top priority, above conventional generation. New resource planning since 2004 must include energy efficiency resources that were not included in the earlier RMR calculations.

Energy efficiency may reduce resource needs, if the removed load occurs during times of peak demand. Lowering the amount of street lighting, for example, would reduce energy consumption, but does so mainly at night. It thus would be of little value in meeting RMR requirements. A much better approach would be to implement higher efficiency air conditioning, forced ventilation to cool buildings at night, or improve insulation and ductwork. This form of efficiency usually corresponds well to patterns of peak summer demand, when electric system resources are most strained.

Demand Response

Demand response is an agreement with the utility company, usually by large commercial or industrial customers, who agree to reduce their electricity consumption during hours of peak demand. This reduction may result in absolute savings in their consumption, or they may simply defer electricity usage until hours when the demand reduction is not needed. Whether or not Demand Response reduces electricity consumption, it does reduce the total load during peak hours. This reduces the need for new power plant capacity. It also means that there is less need for operation of power plants that would meet the peak demand. In fact, typically the dirtiest and least efficient plants would be removed from operation first. So, Demand Response reduces fuel consumption for power generation and reduces pollution. A Demand Response contract can be considered equivalent to power plant capacity as far as reliability is concerned, and is actually worth more than a power plant due to avoided electrical line losses.

Distributed Generation

Distributed Generation ("DG") includes any generation capacity that is installed near or at the location where the electricity is consumed. Particularly relevant is any form of solar energy, such as photovoltaics, that meets peak demand, or Combined Heat and Power (CHP) plants, which generate electricity whenever it is required. The amount of CHP is unpredictable at this point, but there is a major expansion in the works for photovoltaics in the state due to the California Solar Initiative, which should result in the installation of 100 megawatts per year, or more, over the next decade in the investor-owned utility regions.

As San Diego has excellent solar resources, and the highest utility rates in the state, it would be reasonable to assume that up to 10 megawatts of photovoltaics will be installed each year in SDG&E service territory. By 2009, this could add 30 megawatts to the region, of which 60% might be considered to be reliable for the RMR criteria. This will add 18 megawatts of reliable demand side resource, to which about 9% must be added to make it equivalent to generation side resources. Thus, 18 megawatts of reliable photovoltaic capacity would be worth nearly 20 megawatts of RMR capacity.

Existing and Future Energy Supply and Demand

The following table summarizes the existing and future potential resources by 2009 that have been discussed above, none of which were included in the SDG&E forecasts in 2003 as reliability resources. It shows the possibility for an additional capacity of 1848 megawatts, without any more new power plants than those already announced, and without any additional transmission projects for bringing in power from out of the region:

Table 4. Actual and Potential New Peak Resources for SDG&E between 2003 and 2009.

Strategy	Capacity
New Power Plants (2003 to 2006)	590 Megawatts
Planned Power Plants (online 2007 to 2009)	612 Megawatts
Upgrading SOS transmission (within county)	311 Megawatts
Uncommitted Efficiency in 2009	55 Megawatts
Dispatchable Demand Response in 2009	260 Megawatts
Distributed Generation in 2009	20 Megawatts
Total New Resources by 2009 (actual plus potential)	**1848 Megawatts**

Of course, all these resources may not necessarily be up and running by 2009, but at least half of this capacity, including power plants already built, demand response, energy efficiency and distributed generation is a reasonable "base case" assumption. This would mean about 900 megawatts added to 2003 projected resources.

In order to determine what level of resource is sufficient, the added capacity must be compared to projected demand. This is complicated by the fact that past demand projections have been overestimated. For example, in 2003 SDG&E submitted projections to the California Public

Utilities Commission that in 2005 they would need to meet a demand of 4504 megawatts, and that their resources could not meet this target. The projected shortfall was 69 megawatts. Two years later (in 2005), they changed the 2005 demand figure to 4370 megawatts, a downward revision of 134 megawatts. **In addition, the 2003 SDG&E projection relied on the assumption that no power generation in the San Diego basin would come on-line between 2004 and 2023. Both of these assumptions turned out to be false.**

New resource requirements were all shown to be met by major new transmission lines that have so far proven to be unnecessary, 700 megawatts in 2008 and another 1000 megawatts in 2013. In fact, generation had come online before the end of 2005: revisions plus the 46 megawatt Miramar plant pushed the new resource requirements downward by 180 megawatts in just 2 years. The result was a robust 2005 surplus of 111 megawatts rather than the projected 69 megawatt shortfall.

A comparison between projections is instructive. The revised November 2005 projection removes 605 megawatts from the generation resource requirement in 2016, compared to the 2003 projection, roughly equivalent to a full replacement of the South Bay Power Plant. This shows how changing from one projection to another can add or subtract the need for large power plants with relative ease.

Table 5. Comparison of Demand Projections made by SDG&E in 2003 and 2005

	2009	2010	2011	2012	2013	2014	2015	2016
Peak Customer Demand (2005 "base case")	3921	3984	4046	4109	4171	4232	4290	4348
Reserve Margin (15% Demand)	588	598	607	616	626	635	644	652
2005 est. Firm Peak Requirement	4509	4582	4653	4725	4797	4867	4934	5000
2003 Projection (90/10)	4937	5031	5125	5219	5313	5408	5506	5605
2003 Demand Overstatement vs. 2005 Base Case Projection	**+428**	**+449**	**+472**	**+494**	**+516**	**+541**	**+572**	**+605**

Using the updated 2005 "base case" projection is thus equivalent to building a new South Bay Power Plant replacement. Note that this does not say that a replacement plant is or is not needed. Such a decision would depend on matching demand projection with actual resources brought online, and must subtract the capacity of any power plants that are retired. **Yet, the comparison of projections just two years apart shows how important it is to keep an eye on revisions in projected demand.**

During the same period, between 2009 and 2016, additional demand response, energy efficiency and local distributed generation resources are projected, beyond the figures cited above. The following table shows expected deployment:

Table 6. San Diego Region Generation from 2009 to 2016

2003 Projected Generation (G-1)	1935	1935	1935	1935	1935	1935	1935	1935
New Generation	590	590	590	590	590	590	590	590
Retirement of SBPP	-700	-700	-700	-700	-700	-700	-700	-700
Total Generation	**1825**	**1825**	**1825**	**1825**	**1825**	**1825**	**1825**	**1825**
Projected Transmission (N-1)	2500	2500	2500	2500	2500	2500	2500	2500
Transmission Plus Generation (G-1/N-1)	**4325**	**4325**	**4325**	**4325**	**4325**	**4325**	**4325**	**4325**
Efficiency	55	118	175	225	278	345	417	486
Demand Response (DR)	260	264	267	271	276	279	282	286
Distributed Generation (DG)/ and CHP (to be developed with CEC)	-	-	-	-	-	-	-	-
Total On-site Resources (Efficiency plus DR and DG)	315	382	442	496	554	624	699	772
Total Resources	**4640**	**4707**	**4767**	**4821**	**4879**	**4949**	**5024**	**5097**
2005 Peak Requirement (including 15% reserve)	**4509**	**4582**	**4653**	**4725**	**4797**	**4867**	**4934**	**5000**
Surplus/(Shortfall)	**131**	**125**	**114**	**96**	**82**	**82**	**90**	**97**

The above chart makes several assumptions. First, it includes only power plants and transmission line that have been brought online to date. Second, it relies on current projections for on-site resources, which excludes distributed generation and Combined Heat and Power (CHP) that may be added in the future. Requirements for including distributed generation in utility resources are supposed to be established this year by the California Energy Commission and the California Public Utilities Commission. Both agencies place high priority on distributed generation, so this should add significantly to the numbers on the resource side, or make up for potential shortfalls in efficiency and demand response projections.

The scenario above also assumes that planned new in-basin generation, and the additional in-county transmission line in the South of SONGS (SOS) corridor, *is not built*. These combined equal another 923 megawatts of potential capacity, which if they were included could bring regular surpluses in excess of 1000 megawatts even with full retirement of the South Bay Power Plant. Yet, surpluses of 82 to 131 megawatts are projected even without the additional power plants or the SOS added transmission. This also assumes full retirement of the South Bay Power Plant, with no capacity replacement.

In summary, the region has numerous options in addition to the Green Energy Options Portfolios presented in this report to replace the energy capacity provided by the South Bay Power Plant; a full capacity replacement should only be necessary if all the other options fail. The resources listed below can be used to meet projected demand requirements, replace a shortfall in meeting on-site resource targets, replace further generation capacity retirements, or meet an unanticipated increase in future demand. These options in total can add more than 2300 megawatts of electric system capacity, which should be able to meet the contingency needs of the county for years out into the future. The options include:

- SDG&E fulfills its responsibilities to deploy demand response, energy efficiency, distributed renewables and Combined Heat and Power Facilities, adding 772 or more megawatts.[10]
- Future additional electric generation capacity, such as the Otay-Mesa Generating Station, and/or other smaller plants, results in 612 megawatts or more of new capacity.[11]
- Construction of the South of Songs Transmission line adds 311 megawatts of capacity.[12]

10 SDG&E, Annual Aggregate Energy Resource Accounting Tables, Appendix IIA, Table B17, November 15, 2005.

11 California Energy Commission Energy Facility Status, updated February 18, 2004.

12 SDG&E, Annual Aggregate Energy Resource Accounting Tables, Appendix IIA, Table B17, November 15, 2005.

Summary of ISO RMR status and Scale of Energy Replacement Needs

The RMR rating for the South Bay Power Plant is a moving target partly because of new generation and transmission projects that are coming on line or that will be built in the future. We are presenting three scenarios that provide capacity for different RMR replacement levels, as what capacity will actually be needed to replace the existing South Bay Power Plant's capacity is highly uncertain.

Two different strategies are possible for addressing a high case RMR requirement. The first is to apply the highest, 90 percent replacement scenario. The second would be to supplement a smaller Bay front power plant with the smaller portfolio.

The ISO board has removed the RMR status from Unit #3 of the South Bay Power Plant for 2007. Unit #3 is considered to 174 MW of dependable capacity. This reduced the total RMR burden on the SBPP down to 515. As the language of the Cooperation Agreement states the replacement plant only has to be as large as needed to remove RMR from South Bay, the solutions presented in this report will become significantly more affordable.

Finally, there are a number of resources that are not counted in the current RMR projections for the San Diego region. Some of these resources, such as demand response, distributed generation, and energy efficiency, are required by state regulation to come on line over the next three to ten years amount to literally hundreds of megawatts of capacity. Others, such as insuring the proper, full accounting for the Palomar Plant, and adding an extra transmission line on the existing corridor to the San Onofre Nuclear Plant, are least cost solutions for adding capacity. Addressing these issues is essential before any decision is made to commit hundreds of millions of dollars of ratepayer funds into a new bay front power plant, particularly when other solutions to the region's energy needs exist which are environmentally superior, carry lower risk, and represent a far better investment than betting the entire bank on natural gas.

4. Green Energy Options: Three Portfolios for Cleaner More Sustainable Energy for the Region

This section outlines the Green Energy Options (GEO) portfolio alternatives to a new 620 MW replacement power plant, for a range of possible RMR capacities for the South Bay Power Plant.

90% Replacement Capacity Green Energy Option

Portfolio that replaces 90% of 700 MW Capacity

- 400 MW Wind Farm with 150 MW Pumped Storage and Transmission project
- 220 MW Natural Gas Plant
- Solar Concentrator Plant powering a 160 MW Peaker with natural gas backup,
- 20 MW Photovoltaics
- 20 MW Peak Demand Reduction

70% Replacement Capacity Green Energy Option

Portfolio that replaces 70% of 700 MW Capacity

- 325 MW Wind Farm with 90 MW Pumped Storage and Transmission project
- 190 MW Natural Gas Plant
- Solar Concentrator Plant powering a 160 MW Peaker with natural gas backup,
- 20 MW Photovoltaics
- 20 MW Peak Demand Reduction

50% Replacement Capacity Green Energy Option

Portfolio that replaces 50% of 700 MW Capacity

- 150 MW Wind Farm with 60 MW Pumped Storage and Transmission project
- 90 MW Natural Gas Plant
- Solar Concentrator Plant powering a 160 MW Peaker with natural gas backup,
- 20 MW Photovoltaics
- 20 MW Peak Demand Reduction

5. Description of Green Energy Technology Options

The three portfolio alternatives to installing 650-700 MW firm capacity generation replacement on the Chula Vista Bayfront utilize technology and investment options that are viable and ready for implementation, involving multi-year commitments of local jurisdictions that may be used to finance alternative energy portfolios and accelerate renewable investment in Chula Vista and throughout San Diego County. This section describes in detail these technology options and how they could be developed here.

Hybrid Wind Farm & Pumped-Water Storage Facility

Size Range:	**150 to 400 Megawatt Capacity Wind Farm, 60 to 150 Megawatts Pumped Storage**
Cost Range:	**\$170 to \$540 Million for the Wind Farm; and \$80 to \$210 Million Pumped Water Storage**
Est. Power Cost from Wind Farm:	**4.8 cents/kwh**
Est. Power Cost from Wind plus Pumped Storage: (See Appendix A)	**9.6 cents/kwh**

A wind farm and pumped storage serve as insurance against increasing natural gas prices, as the cost is essentially fixed and is the part of the portfolio that is completely independent of fuel prices. Wind power also partly serves to round out load requirements that are not fully met by solar energy alone. While wind is intermittent, the pumped storage facility makes the electricity generated by the wind highly reliable and usable at any time it is required. Thus the pumped storage, while adding significant expense, also adds great utility and value.

Wind power is easily the lowest cost renewable generation option, in the last several years globally averaging \$1000 to \$1200 per kilowatt of capacity for a large wind farm. High demand has recently pushed the cost of wind farms higher, with a range between \$1300 to \$1750 per kilowatt; the lower range should be achievable with good planning and also once manufacturing capacity catches up to demand. In fact, 2006 DOE projections are that wind farms should return to the previous low levels by the end of the decade, though our cost projections do not assume this. Should this happen, then economics of the wind farm will become very favorable.

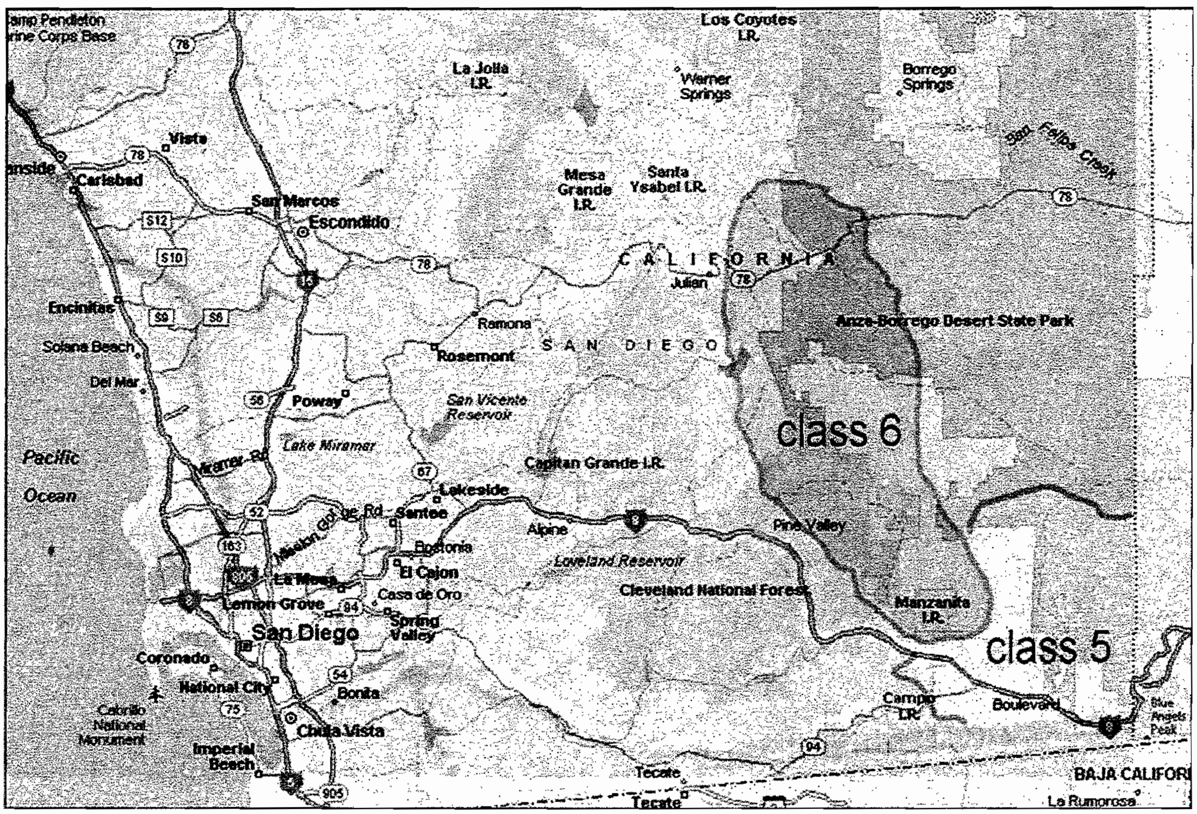
Wind turbines have become very reliable, and warranties on product defects cover investors from the most serious capital risks during the early years of operation. With proper operation and maintenance, wind turbines have a life expectancy of 20 to 30 years.

The most important factor in the cost of electricity from a wind farm is the available wind resource. Wind power resource goes up geometrically in proportion to the cube of the wind speed. Thus, even small increments of average wind speed can make a significant difference in wind generation. It is critical first to find areas with the best wind and then to follow this up with careful measurements of at least one year at the locations under consideration.

Wind resources are conventionally measured according to “Classes” ranging from 1 to 7. A class 3 wind is the usually the minimum for commercial development. A class 3 site would ordinarily only be used when other factors make it desirable, such as a location close to where the power will be delivered. For sites that require transmission of electricity over a distance, a minimum of class 5 is highly recommended.

Parts of Eastern San Diego County have some of the finest wind resources in California (Class 5 and Class 6). A considerable amount of this area is in national park, forest or other protected areas, and thus is effectively off limits to development. However, there are high wind areas in the Southeast County that may be more suitable for a large wind farm (Figure 1).

Figure 1. San Diego County Wind Resource Regions.



The second major factor affecting the cost of wind is financing. Private developers require significant rates of return that can add to the cost of wind. This is usually offset by the federal wind tax credit, currently 1.8 cents per kilowatt-hour paid for the first 10 years of the wind farm’s operation. Since Chula Vista is not a tax paying entity it is not eligible for the tax credit, however its low cost financing resources using municipal bonds can essentially equal the benefit of the tax credit. This means development plans can be independent of federal tax policy, a frequent stumbling block for wind projects. In addition, the benefit of low cost financing extends for the full life of the asset, while the tax credit is limited to 10 years.

Utilizing municipal financing for a large wind farm with class 6 winds would likely result in wholesale electricity costs of 5 cents per kilowatt-hour or less. This makes wind power competitive with the long-range expected cost of electricity generation from base load plants. Wind powered electricity can be sent directly over the transmission grid, but its variability means that it is not reliably producing power at the times it is most needed. To make the wind generation reliable, it must be backed up with other generation resources. Vendors of contract wind power usually make use of natural gas generation to provide a 24-hour base load service.

Since this off-peak character of wind power is not part of the service provided by the existing South Bay Power Plant, selling the power to wholesale buyers or a CCA requires a way to transfer the energy output to those hours when it is needed, and the design of this component must be included (and is included in this Plan) in its financial modeling. In order to project the competitiveness of the large scale solar concentrator turbine facility and wind turbine facility, this Plan includes the fully integrated "Hybrid" packages rather than just isolated RMR-related component, investment scale, and paybacks. An energy storage system, which takes the power produced at night and makes it available during the day, is the way to achieve this functionality. Pumped Storage is the only affordable, practical way to store this amount of energy, in which water is pumped to the top of a reservoir at night when the wind blows, and the water is released the following day to run hydroelectric turbines. Modern systems allow for a single unit to serve both as pump and turbine, which reduces the capital expense.

The GEO's proposed Pumped Storage facility places an additional cost for peak power that can add about 3 to 4 cents/kwh to the cost of energy that is used to pump the water into the storage. At current and forecast future natural gas prices, pumped storage can be competitive to projected peak power from competing natural gas power plants. Hybridizing the facility also enables the lower-cost wind power to offset the higher cost Pumped Storage power. This is because only a part of the power generated by the Wind Farm is used for running pumps on the Pumped Storage Facility, with the remainder of the wind power being sold as part of a competitively priced, stable energy supply. While pumped storage facilities can be expensive, their cost can be reduced by using existing reservoirs. There are reservoirs in San Diego County, most notably in the East County, which might be suitable from the standpoint of location, size and sufficient elevation drop below the reservoir. Also, the Lake Hodges Pumped Storage project may provide a feasible market for selling excess wind generation, and should be evaluated by Chula Vista and any partners. Finally, while Pumped Storage adds substantially to the cost of the Wind Farm's power, power delivered during peak hours has a large premium value in the wholesale power market. This facility will serve as a hedge should natural gas prices increase in the future, which is widely predicted. In addition, the pumped storage facility will outlast the wind equipment by decades. Once financing costs have been covered during the financing period, the pumped storage cost will be reduced to operation and maintenance, which means that the cost to generate electricity will be very cheap and the profit margins quite large. In this way, the pumped storage facility is a long term investment.

Hybrid Solar Concentrator Turbine with Natural Gas Backup and Cogeneration

Size Range:	**160 MW**
Cost Range:	**$350 to $450 million**
Power Cost without Cogeneration:	**10.2 to 12.2 cents/kwh**
Power Cost with Cogeneration:	**9.1 to 9.28 cents/kwh**

(see appendix B)

Solar thermal generators have been reliably delivering hundreds of megawatts of power into the California grid since the 1980s. This technology uses parabolic mirrors to collect light and concentrate the heat of sun onto a long tube filled with a fluid. These mirrors track the sun, and thus produce power all day long at a fairly consistent level in sunny locations. In one variation, the fluid transfers the heat to a second fluid, such as water, that turns to steam and runs a conventional turbine. The conventional turbine can also be run off of natural gas on days when the sun is not available. This provides a very high level of reliability while greatly limiting use of natural gas. Such a system can completely replace the functionality of the current South Bay Plant.

One major problem with solar thermal generation has, in the past, been lack of availability. This limitation is rapidly disappearing, as new solar thermal manufacturers and installers are beginning to emerge all over the world, including in the US. Recently a one megawatt solar thermal power plant in Arizona was completed, and a 64 megawatt plant in Nevada is under construction. The 1 megawatt plant was quite expensive: at about $6000 per kilowatt it is 5 times more costly than equivalent sized wind farms. The larger plant in Nevada reduced the unit cost by about 40%, due to improved design, experience, and some economy of scale. This technology is expected to continue to decrease in cost, which will be necessary to make it directly cost competitive with peak power from natural gas generators. However, it is easier to acquire and permit real estate for Solar Concentrators, making it feasible in many areas of California where there is sufficient relatively level land.

For a local resource, power prices from solar concentrators are expected in the next 5 to 10 years to become a competitive, locally available power source, especially when transmission already exists or no new significant transmission is required. The Nevada solar-trough thermal generating plant costs about $3500 per kilowatt, but the installer says that a larger plant of 160 megawatts, such as Local Power is recommending for Chula Vista, will be significantly cheaper. A combination of further development of the industry, and a larger scale project, should begin to make solar thermal technology directly competitive with long-term expected cost of comparable natural gas plants. The projection of $2500 per kilowatt is in line with industry expectations and DOE price projections.

We also strongly recommend that a solar thermal project be co-located with a facility that can use and purchase the "waste" heat; an application referred to as co-generation or combined heat and power (CHP). This can make solar thermal generation significantly more cost effective, and also provide a secondary commercial development opportunity.

Solar concentrators have been around for over a hundred years. We estimate that a 160 megawatt project would require approximately 900 acres; however, if the cost for solar concentrators continues to drop, a smaller facility may become economical. The sites mentioned in this report, such as those near Sycuan, and Ream Field, have been initially evaluated and may prove adequate in size and solar conditions to provide affordable local power. The resource for solar energy is optimal in the East County, but a development nearer to Chula Vista would come close to matching the effective cost to produce electricity if transmission charges can be avoided. Further site acquisition and permitting analysis is warranted and land-owners would need to be solicited about their interest in such a project in a timely manner.

A natural gas plant that provides assured power is an essential part of the portfolio. It provides a benefit if natural gas prices are lower than the threshold required to make the fixed cost renewables profitable. It is thus a kind of insurance should natural gas prices remain below current levels of $6 to $7 per MMBtu. But even if prices are sustained at $5 per MMBtu, the total portfolio cost of energy is only a fraction of a cent per kilowatt-hour above prevailing costs to run a natural gas turbine generating at an equivalent capacity, an increment that is less than half the premium that the renewables would have by themselves. This illustrates why the natural gas component is a critical part of the GEO investment portfolio. This hedge is more valuable than it would be for a private third-party investor, because the low return on municipal bonds decreases the expense of owning a power plant. This margin of savings is larger for a peaking plant than for a base load plant, since the cost of the plant becomes more significant as less fuel is consumed. The relative savings due to municipal financing, however, are not nearly as large as they are for highly capital intensive renewables like wind, pumped storage and solar thermal, where the fuel cost is very low to non-existent.

Photovoltaics with Energy Storage or Demand Response

Size Range: **20 MW**
Cost Range: **$120 to 160 million**
Power Cost: **25 to 30 cents/kilowatt-hour after rebates; 8 to 12 cents/kilowatt-hour for commercial owners who can also get tax credits.**
(See appendix D)

Photovoltaic power is the direct conversion of sunlight into electricity using semiconductors. The most common semiconductor is a thin wafer of silicon with minute amounts of boron and phosphorous that gives the silicon an electric charge. The silicon wafers are mounted in panels that generate electricity any time they are placed in sunlight. The materials are highly durable, with some testing suggesting lifecycles as high as 80 years or more. Since the technology is modular and flat, the panels can be placed almost anywhere. Frequently rooftops are chosen, but shading structures over parking areas or placement in open areas are also frequently seen.

Present full installed costs for small residential systems average about $9500 per kilowatt, while larger commercial or industrial sized systems average about $8000 per kilowatt, though some facilities have been installed for as little as $5000 per kilowatt.[13] Over the next five to ten years, the cost of photovoltaics is expected to continue to decrease, and numerous technology options and economies of manufacturing scale will facilitate this.

Photovoltaics are still one of the most expensive electric generation technologies, resulting in a full cost of electricity (before rebates) ranging between 20 and 40 cents per kilowatt hour. Yet, despite this fact, there are opportunities to make an investment in this technology cost effective.

Deploying photovoltaic systems at the location where electricity is consumed gives it a premium value over the wholesale power which cost the utility company 5 to 8 cents per kilowatt hour. SDG&E sells this power at 13 to 18 cents per kilowatt hour to customers, and this is much closer to the cost of photovoltaic electricity. Photovoltaics, however, does not compete with the *present cost of electricity*, but rather with the *expected cost of electricity* over the next decades against which it represents insurance. This fact enhances its value substantially. (This point is also an important factor for evaluating the other renewables in the portfolio.) NOTE: Since photovoltaics, as envisioned in the GEO, are developed as generators at customer sites, and may even be owned directly by customers, they are not included in the wholesale electricity price calculations for the GEO portfolios.

If customers take advantage of state rebates and tax credits, then the balance can be shifted decisively in favor of these solar energy systems. The fact that thousands of customers have taken advantage of subsidies shows that the potential market is quite large. The recently enacted California Solar Initiative provides rebates out to 2015, currently $2500 per kilowatt, and set to decrease when specified benchmarks of solar installation are met. Solar energy systems over 100 kilowatts in size will receive a performance incentive, paid out over a few years based on the electric generation of the system. Smaller photovoltaic installations will usually get their rebate at the time of purchase. In addition, businesses can take a tax credit for 30% of the installed cost

13 Data: California Public Utilities Commission.

of the photovoltaic system until 2008. This will either revert to a 10% credit unless the 30% credit is extended, which several bills in Congress propose to do.

Building to larger scale is another way to save on cost, as small home-sized installations can be about 10% to 20% more expensive on a unit basis. The economy of scale is not at present great enough to make building large photovoltaic generating stations cost effective, though this may change over the next decades as solar energy costs drop and electric rates continue to rise. Last year 1.5 billion watts of photovoltaics were installed around the world, about a ten-fold increase since 1995. During that time the average cost dropped by at least 35 percent. Installing two megawatts per year would require development of multiple sites, since the cap for rebates is likely to be 1 megawatt. Two megawatts was selected as an annual target as this is believed to be the minimum demand required to attract a solar panel manufacturer to the region to support part of regional goals for promotion and development of a green energy economy. Also, the electricity must be usable on-site and few customers use this much electricity. The cost would be about 12 to 15 million dollars per year, assuming large scale deployment and economies of scale. This range is likely to be valid until the end of this decade, though technology improvements will continue gradually to lower the cost over time.

Cogeneration for peak capacity

Cogeneration, also called Combined Heat and Power, uses thermal sources such as natural gas for more than one purpose simultaneously. The heat is first used to generate electricity, which typically only uses about 35 percent of the energy, though the most efficient modern combined cycle base load plants can reach up to 60 percent efficiency. The rest of the heat normally is wasted in the atmosphere, but cogeneration uses the heat to do further work. Normally this is for an industrial process that would use the fuel in any case, but now the fuel does double duty. This can raise the net efficiency to as high as 90 percent, which a substantial savings in both cost and fuel. There are also environmental benefits, while CO2 reductions can approach even the most aggressive climate protection goals. The most efficient way to use combined heat and power is to match it with the on-site needs for heat. But using it intermittently for peak power also realizes significant savings and environmental benefits. This is an important way to help bring down the cost of solar thermal and natural gas peak power generation, though the expected efficiency levels are not as high as for base load plants.

Energy Efficiency, Demand Response and Conservation

Energy efficiency can also be turned into a peaking resource, if the load that is made more efficient matches the peak periods. Determining this may require some research into local demand patterns. Examining the load curves will show what sector the demand is coming from, but it is equally important to find out what appliances are creating the load at the particular time in question. Daytime loads might be offset by more efficient office lighting and other office equipment. Evening summer peak load in California frequently comes from air conditioning. Building insulation, sealing ductwork and building envelopes, measuring internal thermal flow and pressure patterns, and installing more efficient air conditioning are keys to addressing this late afternoon to early evening demand. Adequate training of personnel and inspection of air conditioning refrigerants also help. Any efficiency program requires the most stringent monitoring, which just as important as prescreening. The program should set clear goals that match the load requirements that the power plant currently fills, and they should be monitored for actual savings in kilowatt hours and peak building demand patterns. This is much more efficiently done in large commercial structures, but addressing the residential sector may be critical for offsetting the electric system's evening power demand.

Demand response is far more easily accepted by the ISO as a legitimate power resource, particularly if customers in a demand response program are bound by usage contracts that specify when and how much demand curtailment will be applied. This is done by central dispatch, using automated controls, though up to this point such dispatch can be rather brutal. A CCA could create its own demand response program that allows for flexibility and customer choice. Importantly, such a program can be implemented with little capital investment, and forming an agreement with a customer is an ideal entry point for bringing in a wide range of attractive energy services, including photovoltaics, efficiency measures, backup emergency power, power conditioning equipment to assure high quality, and energy audits. Demand response is much more cost-effective with large commercial or industrial customers. Programs are more successful when the customer receives a financial reward, such as lower rates. Since many of these customers are on time-of-use rates, there is built in support in their electric rate structure. The key is to enhance this value while minimizing sacrifice from the customer.

6. Key Investment Mechanisms and Financing

This section identifies the process and programs by which the City of Chula Vista could recoup their green investments and raise revenue. It contains an analysis of implementation structures that would be needed, financing, and public programs that support or affect clean energy projects.

Community Choice Aggregation (CCA)

Community Choice is a key strategy in Chula Vista's ability to develop the renewable energy facilities on a scale that will reduce or eliminate the need for generation on the SBPP site.
CCA is technically easier to implement and less risky than a municipalization, but facilitates local control over energy resource planning. Under a CCA, Chula Vista would procure power on behalf of residents and businesses; SDG&E will continue to provide distribution, meter-reading and billing services, and would remain the Provider of Last Resort.

CCA is an established, successful method of procuring competitively priced energy services. Nationally, CCA uses economies of scale to leverage lower prices, cleaner power and better service. Since 1997, CCA Laws have been passed by New Jersey, Ohio, Massachusetts, California, and Rhode Island. All of Cape Cod formed the nation's first CCA in 1997, and has provided electricity service and energy efficiency services at below-market prices since then. The Cape Light Compact is a regional services organization made up of all 21 towns of Cape Cod and Martha's Vineyard, and Barnstable and Dukes counties. The purpose of the Compact is to represent and protect consumer interests in a restructured utility industry. As authorized by each town, the Compact operates the regional energy efficiency program and works with the combined buying power of the region's 197,000 electric consumers to negotiate for lower cost electricity and other public benefits. The Compact provides

1) Aggregated power supply

2) Consumer advocacy

3) Energy efficiency programs such as low income, residential, commercial and industrial, and education programs

Cape Light Compact, emphasizes a comprehensive approach, undertaken with legal and technical support – as the electric industry continues in its transition to a competitive market.

In Ohio, CCA represents nearly all of the state's competitive electricity market, with the Northeast Public Energy Council serving approximately 500,000 customers since 2000, with a 70% cleaner portfolio than utility service at prices consistently lower, even after changing suppliers. Forty California municipalities and counties are now evaluating Community Choice, 27 of them are seeking to double or more the state Renewable Portfolio Standard (RPS) targets.

Apart from providing revenue for the repayment of renewable energy investments, CCA offers Chula Vistans transparent, structured rates. "Political rate-setting" may be avoided by requiring prospective suppliers to "meet or beat" SDG&E's current rates, be selected through a competitive bidding process, and commit to a locally-set rate schedule. Chula Vista, or a regional CCA, may set a Renewables Portfolio Standard (RPS) for the community and require suppliers to design, build, operate and maintain renewable energy and conservation facilities as portfolio components of the service. CCA enables a maximum level of performance risk to be placed on the energy rather than the City's General Fund. With significant revenues secured under a CCA contract, City program costs can be self-funded from a small increment of revenues. A single supplier approach allows for greater performance accountability, protecting both the City's General Fund and new customers against energy market risk. Double-Bonding may be used to insure risks associated with both commodity services and facilities construction. Finally, participation is voluntary. After the City signs a contract under specific terms, every customer will receive four notifications comparing the CCA's deal to SDG&E's terms, and be free to opt-out without penalty over a 120-day period.

The repayment of Chula Vista energy investment may be made directly through CCA, or indirectly by selling power to another party. Directly, Chula Vista could provide for the power needs of its own residents, businesses and public agencies, guaranteeing power sales from a renewable energy facility integrated into the Specific Plan – delivering fixed prices and energy independence to the local economy. Indirectly, Chula Vista could build a facility to sell power to the Southern California Public Power Agency (SCPPA), or to the wholesale power market. With other municipalities in the region considering CCA, power may also be shared among CCAs. Either approach would enhance the uniqueness and sustainability of the renewable energy facility development and deliver profits to the city and significant local economic development – all at very low risk.

Community Choice is an authority granted by California law (AB 117, Migden) that allows cities and counties to take charge of their own energy future. Under Community Choice, local governments can serve as a virtual "electricity buyer's cooperative" for local residents, businesses and government agencies. Unlike ordinary cooperatives, however, the day-to-day management for securing electricity supplies is managed by a qualified and experienced third party, while the local government is placed in the role of strategic planner.

The government entity, called a Community Choice Aggregator (CCA), contracts with existing licensed suppliers called "Electric Service Providers" (ESPs). Other public entities, such as SCPPA or other inter-municipal association, may also purchase and sell power. ESPs are often the optimal vehicle because they are risk-bearing retail entities, in the business of providing reliable and cost-competitive electricity for large businesses and government agencies. About 12 percent of California's electricity is currently purchased from Electric Service Providers.

If it were to desire to form a **CCA Joint Powers Agency**, Chula Vista should investigate partnering with other municipalities, principally, National City and Imperial Beach. Imperial Beach in particular has articulated interest in such partnering concepts.

Municipal Revenue Bonds (H Bonds)

The Chula Vista City Council has the authority to issue revenue bonds unilaterally, or to form a partnership with other local government entities in a joint venture to share the risks and benefits of a renewable energy network with other governments on a regional basis.

Joint Powers Agencies, Native American Tribes, other cities and ports also have the authority to issue revenue bonds, either based on a new revenue stream or existing assets or contracts. There are several key entities in or near Chula Vista which should be considered for a potential financing partnership. We have identified specific opportunities for Chula Vista to issue H Bonds in conjunction with other local public entities, any of which could participate in a CCA, co-finance and co-own green power facilities, and host facilities on their list of lands and properties:

- Native American Tribal Governments in or near San Diego County have land suitable for Solar Concentrator and Wind Power Facility, and are pursuing commercial green power development;
- Southern California Public Power Agency members already co-develop power plants and could partner to develop and take power from a Solar Concentrator or Wind Farm Hybrid as municipal utilities;
- San Diego County owns reservoirs and land suitable for the proposed Wind and Pumped Storage Facility;
- Port of San Diego could co-finance a green power facility and purchase power as a member of a CCA;
- U.S. Navy is an active developer of solar photovoltaics, has land suitable for green power facilities, and is a major energy user.

The specific scenarios involve an integrated use of H Bonds in conjunction with a CCA. H Bonds are generic municipal revenue bonds used to finance renewable energy and energy conservation facilities. Chula Vista, and any other city, has the opportunity to issue H Bonds based on a new revenue source. There are three categories of H Bonds:

- First, a municipality, JPA or public agency partnership may own its electric utility, and secure H Bond repayment through the guaranteed monthly bill payments of captive utility customers. This option has been foreclosed by Chula Vista's Franchise Agreement with SDG&E in 2004, which appears to prevent Chula Vista from providing wires services alone or with another party, including transmission;
- Second, a municipality may issue H Bonds to finance facilities that will operate without a guaranteed retail customer, selling power with a degree of risk mitigated by long-term contracts with public agencies such as the Southern California Public Power Authority in a long-term agreement, and/or selling power in long-term contracts on the wholesale power market.
- Third, a municipality may form a Community Choice Aggregator (CCA) formed pursuant to AB117 (2002 – Migden) and secure repayment of H Bonds based on monthly electric bill payments of participating residents, businesses and public agencies.

H Bonds and CCA

H Bonds provide CCAs with considerable flexibility. They can be used to finance renewable energy generating units and other revenue producing elements of CCA, such as storage facilities and conservation facilities. H Bonds can be supported by existing public agency assets and enterprises, or by new assets or enterprises such as renewable energy generating units. Finally, revenues from a contract with an Electric Services Provider ("ESP") may support H Bond repayment, with or without assets or enterprises.

H Bonds and CCA are extremely synergistic. Together, they (a) provide both the means to develop renewable energy and energy efficiency resources, and the market to utilize and pay for those resources; and (b) provide CCA with a secure base of resources with which to serve its customers and, thus, avoid excessive dependence on a volatile energy market. Whether the H Bonds will qualify for tax-exempt status and other factors affecting their marketability are dependent on the structure of the transaction being financed. Specific structures are discussed below.

As a rule, in order to qualify for tax exemption, the facilities that are financed must be owned by a governmental entity or operated by Chula Vista or other governmental entity – or by a nongovernmental entity on behalf of Chula Vista pursuant to a contract that meets certain requirements prescribed by the Internal Revenue Service. Even if not tax-exempt, H Bonds could still be issued to finance facilities which make solar and other technologies more affordable to local residents and businesses, albeit at a slightly higher interest cost than government-owned facilities would pay – but could also take advantage of significant federal tax benefits.

Application of H Bonds to CCA [14]

H Bonds can be used in a variety of ways. From a strategic business perspective, H Bonds and CCA were developed to work together. Without CCA, renewable energy and energy efficiency projects financed by H Bonds would have to search for a market for the power output. With CCA, major recurring revenues from community-wide retail electric sales will repay the investment in clean energy projects.

Alternately, without resources of the sort authorized by H Bonds, a CCA program could not finance new green power facilities; moreover, without a secure base of resources, a CCA would be extremely dependent of the energy market to serve its customers. The energy crisis of 2000-2001 dramatically demonstrated the danger of over-dependence on a volatile energy market – a lesson reinforced by fossil fuel price fluctuations this past year, and SDG&E's increasingly volatile electricity rates, reflecting its predominantly natural-gas fired power plant fleet. The specifics of how H Bonds are used in connection with CCA depend on what types of projects are to be financed. Because a driving factor behind most local government's interest in CCA is to utilize renewable energy and energy conservation, a number of projects that meet the parameters for H Bonds would probably be part of a Chula Vista CCA energy plan. Those projects can be financed with H Bonds.

The specific use of H Bonds to most effectively further CCA depends on the particular projects. Three of the threshold questions that must be addressed are (i) what assets or programs would best assist with the implementation of CCA, (ii) what revenue source will secure repayment of the H Bonds, and (iii) whether the H Bonds are tax-exempt or taxable. These items are discussed

[14] "How H Bonds can be used to implement an adopted CCA Implementation Plan," Nixon Peabody LLP, "Analysis for San Francisco Local Agency Formation Commission," November 10, 2005, Accepted by San Francisco Local Agency Formation and San Francisco CCA Task Force, 2006.

briefly below. The first two are somewhat related in that if the items financed do not have an independent or sufficient revenue stream to support the bonds to be issued, a separate revenue stream for the H Bonds must be identified. The question of tax exemption will turn generally on the specific facts relating to ownership and use of the financed items.

Chula Vista General Plan, Policy E 7.5 states that the City sets a goal of 40% clean renewable energy by 2017.[15] San Francisco[16], Marin County, and other cities implementing Community Choice Aggregation have set goals of 50% or higher by 2017. To achieve this objective, Chula Vista's Implementation Plan would contemplate a number of elements that should fall within H Bond financing in order to provide for the development of renewable energy facilities, and could also establish replacement capacity and power for the RMR-contracted elements of the South Bay Power Plant.

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

Sources of Repayment

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

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

In order to constitute permitted "revenue bonds," Chula Vista will need to identify a dedicated revenue source by which H Bonds are to be secured and repaid, whether revenues of a new source or an existing source. As noted, Chula Vista can structure H Bonds to be secured by the revenues from an existing revenue producing entity. Other financing scenarios also exist and are discussed below.

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15 Chula Vista General Plan, Policy E7.5.

16 San Francisco Community Choice Aggregation Draft Implementation Plan, San Francisco Local Agency Formation Commission, May 13, 2005.

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

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

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

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

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

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

Alternative Structures for using H-bonds and Implications for Tax Exemption.

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

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

In general, the "use" of facilities or items financed with the proceeds of H Bonds by an entity other than a state or local government could result in such bonds constituting "private activity bonds." In that case, under Section 141 of the Code, the interest is not tax-exempt. Such use is often referred to as "private use". Private use is present where there are any types of privately held "legal entitlements" with respect to the financed facility. Nongovernmental ownership constitutes private use as do long-term contracts regarding the output to be produced by the facility. For example, a long-term contract with a nongovernmental entity in which that entity agrees to purchase the energy output of a facility will generally constitute private use. In addition, contractual arrangements with nongovernmental entities regarding the operations and maintenance of a financed facility will constitute private use, unless such contractual arrangement is consistent with certain contract parameters approved by the Internal Revenue Service and described below.[17] Last, it should be noted that loans of the proceeds of H Bonds to a nongovernmental person or entity will generally cause the H Bonds to fail to qualify for tax exemption. However, a tribal government could issue tax-exempt H Bonds in conjunction with Chula Vista or a group of public agencies in order to develop or co-develop a renewable energy facility and enter into power purchase agreements for the capacity and power of the facility between the tribal government and the municipality or group of municipalities such as a Joint Powers Agency.

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

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[17] Generally, bonds constitute private activity bonds if they meet either of the following tests:

A. Both the private business use test ("Private Use Test") AND the private security or payment test ("Private Payment Test" and together with the Private Use Test, the "Private Business Tests")); or

B. the private loan financing test "("Private Loan Test").

A bond issue meets the Private Use Test if more than 10 percent of the proceeds of the issue are to be used for any private business use. A bond issue meets the Private payment Test if the payment of the Implementation Plan of, or the interest on, more than 10 percent of the proceeds of such issue is (under the terms of such issue or any underlying arrangement) directly or indirectly --

A. secured by any interest in property used or to be used for a private business use, or payments in respect of such property; or

B. to be derived from payments (whether or not to the issuer) in respect of property, or borrowed money, used or to be used for a private business use.

For purposes of these tests, the term "private business use" means use (directly or indirectly) in a trade or business carried on by any person other than a governmental unit. Use as a member of the general public shall not be taken into account. A bond issue meets the Private Loan Test if the amount of the proceeds of the issue which are to be used (directly or indirectly) to make or finance loans to persons other than governmental units exceeds the lesser of X) 5 percent of such proceeds, or Y) $5,000,000.

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

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

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

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

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

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

In this report, we assume a twenty-year maximum bond repayment within the context of a CCA contract period. However, a 30 year period is used for economic evaluation of a project, since this reflects the normal economic lifecycle. (see Appendix F, Financing). Rev Proc 97-13 focuses generally on the term of the contract and the manner and amount of compensation paid to the service provider. Generally, the more fixed in periodic amount the compensation paid to the service provider, the longer the permitted term of contract. Contracts pursuant to which the service provider's compensation is 80% fixed may be as long as 20 years in the case of service contracts relating to "public utility property". On the other hand, contracts pursuant to which the service provider's compensation is 50% fixed may not have a term in excess of five years. "Public utility property" is defined as property used predominantly in the trade or business of the furnishing or sale of (i) water, sewage disposal services, electrical energy, (ii) gas or steam through a local distribution system, and (iii) certain telephone services and communication services.

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

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

Engagement of CPUC and other funding

Several funding sources have emerged in the recent months. These or other programs should be accessed by the City to provide renewable energy for its residents.

California Solar Initiative

Enacted by the California Public Utilities Commission, this program provides rebates for photovoltaic systems less than 1 megawatt, currently set at $2.50 per watt and decreasing 25 cents per watt as target MW levels of installed solar are met statewide. For systems over 100 kilowatts the rebate will be paid in the form of a performance-based incentive based upon the kilowatt-hours generated in the first years of operation. This will have an effect on financing, since the payment is not made up-front. The CPUC is examining a similar program for smaller photovoltaic systems as well.

The recently enacted SB1, the former "Million Solar Roofs" bill, will place restrictions on the California Solar Initiative, e.g., it rolls back the PUC photovoltaic system size limit of 5 megawatts back to 1 megawatt, and has strict requirements for locating photovoltaic systems at customer sites. This may limit opportunities for a PV landfill project.

PGC Energy Efficiency Funds

These are currently administered by the utility companies in most areas of the state, except San Diego. AB 117 requires opening up funds to community administration for programs of their own design, and SDREO was able to take control of the funds away from SDG&E. This could be quite advantageous for Chula Vista, as a regional planning agency is more likely to be open to a systematic and creative efficiency program of the type necessary to meet grid reliability needs.

This will require coordination between the energy efficiency component and the renewable energy systems, such as local photovoltaic systems and demand response capacity. A well designed program will look at the load curves met by each of these and work to optimize customer as well as system value.

Federal Energy Tax Credits

Private developers of energy projects may be eligible for certain tax benefits that are not available to public agencies. For this reason, it is wise to consider different ownership and financing models to determine which alternative can best meet the desired goals. In some circumstances the low cost of public capital may result in lowest energy costs for publicly owned and financed facilities. On the other hand, very generous tax credits may favor private, third party ownership.

For many years there has been a 10% tax credit for solar installations purchased by commercial enterprises. The 2005 National Energy Policy Act (NEPA) increased this credit to 30% of installed cost of photovoltaic systems for commercial entities; but this will revert back to 10% in 2008 unless it is extended by Congress. Under the same law, homeowners can take up to a $2000 credit on solar energy systems. Public and non-profit entities are not eligible for this credit, since they have no tax liability. In fact, if government agencies provide rebates, or extend credit, to commercial enterprises for photovoltaic or other solar energy systems, they risk voiding eligibility for part or all of the credit based upon the portion financed. Hybrid ownership or financing models can be designed that optimize the balance between the benefit of public funding (such as rebates) and the ability to take advantage of tax credits.

Commercial power project developers may take a 1.9 cent/kilowatt-hour production credit for certain renewable energy generators, paid out over the first ten years of operation according to the amount of electricity generated by the project. The rate of tax credit is indexed to inflation, and thus has increased over time. Congress, in 2005, extended this production tax credit to other renewables such as geothermal and solar projects; this is also due to expire at the end of 2007. A payment system has been set up by the federal government to make equivalent payments to public agencies as well, but this has mostly gone unfunded or underfunded in the past. There is wide interest in extending the solar and renewable production tax credits in the energy industry, in Congress and in the White House.

The production tax credit has existed for a number of years, but Congress only approves this for a year or two at a time. This has created considerable instability in the US wind power industry, with customers clamoring to get their project on line before eligibility ends. Then Congress lets the tax expire for a year or so, and the demand for wind turbines completely dries up. Some renewable projects cannot occur within this time frame, particularly since regulatory approval, environmental review, planning and construction all have to be completed before the tax credit expires. Wind farms are most suited to taking advantage of the tax credit, since the development time can be as little at 18 months, assuming the process goes smoothly. But, in all cases, it is best for a project to begin planning stages in advance, so the project is ready to go when the tax credit opens up again.

Supplemental Energy Payments (SEPS)

This payment structure covers the excess cost of renewable electricity over the prevailing price of natural gas generation. It applies to wholesale power purchased by utilities through contractual agreements that must be approved by the CPUC. *This program may be changed or eliminated in the future, so it may not necessarily be relied upon for project planning.* However, the elimination of SEP payments may leave Chula Vista's renewables at a competitive advantage compared to privately developed facilities. The principle concern is not if the SEPs are eliminated, but rather if they are retained. In this case, it will be important to make sure the city's renewable facilities are eligible for the same payments as any potential competitor.

7. Benefits Comparison of GEO Options to Gas-fired Replacement

This section provides a brief comparison of the risks and rewards of investment in a new gas-fired plant vs. the portfolios outlined above. The three GEO options have significant projected benefits over their lifecycle. Criteria for this comparison include the protection of public health, environmental justice, enhancing energy security, and competitiveness with SDG&E's projected conventional power prices. Financial analysis of renewable facilities is provided in the appendices and supporting spreadsheets. In the analysis it is shown how the lower cost of capital of a municipality achieves a significant long term cost advantages over municipal or private investors in similar projects.

Economic Benefits

Financial Return on Investment

The interest on a commercial loan, and the high rate of return demanded by private investors, imposes a cost on renewables that can be much larger than the original cost of the power plant. For example, a favorably priced large wind plant today might cost about $1.3 million per megawatt (and an unfavorably priced version would likely not get built), which implies that the first GEO portfolio option of a 400 megawatt wind plant would cost $520 million. A private investor, averaging in loans and profits, might require over 11 percent rate of return every single year on the entire capital investment. The interest rate on a municipal revenue bond places a much smaller cost of money on the project, and such bonds are modeled to bear a 5.5 percent or less rate of return. (Current long term municipal revenue bond rates, for well rated bonds, are closer to 4.5 percent). The municipal owner's cost of money is thus half that of a private investor, as the following table shows:

Investor	Cost of Wind Farm	Cost of Money	Term (yrs)	Total Rate	Total Interest plus ROI
Private	$520,000,000	11%	20	220%	$1,144,000,000
CCA Revenue Bond	$520,000,000	5.5%	20	110%	$572,000,000

The private investor pays twice again the cost of the wind farm over a 20 year period, over a billion dollars. The cost of interest on the municipal bond is exactly half as much, which saves $570 million. This savings is worth more than the entire wind farm. While the private developer does have tax credits to offset some of this difference, the main tax credit only lasts for the first 10 years. This gives the municipal investor a large advantage that is difficult to overcome. Since both SDG&E and a CCA would need to procure renewable power, the cost incurred on the customers of SDG&E for a similar supply would be higher. Given that few renewables cost less than wind, this would make it difficult for SDG&E to match the price of such a power supply. This extra cost is embedded in customers' rates one way or another.

The cost of wind power also intersects the likely cost of power from natural gas, even for a private investor. This is partly because of expected increases in the price of natural gas over the next 20 to 30 years, which is the financial life of a wind farm. The DOE expects that natural gas will decrease in price over the next several years, reaching a low of $6.30/mmbtu in 2011. Thereafter, it is projected to increase in price at about 2% per year for the foreseeable future, roughly following general inflation, eventually reaching $11.74/mmbtu. An average price of $8.40/mmbtu during the period implies a cost of natural gas fueled base load electric generation of about 6.6 cents per kilowatt-hour. By comparison, a 20 year investment by a CCA in a wind farm would lead to a cost of 5.5 to 6 cents per kilowatt-hour, to which one must add about half a cent to firm up the capacity so that the power can be sold on the market. If the wind farm is financed using 30 year bonds backed by the capital value rather than a CCA revenue stream, then the cost of the wind power could drop below 5 cents per kilowatt-hour.

Clearly wind is a good investment if you expect the price of natural gas to increase by anywhere close to the rate of inflation or higher. This is one reason why wind is one of the larger elements of the portfolios. But this also illustrates some of the reasons why a CCA or municipality can maintain wholesale energy costs competitive with the utility company. In fact, the CCA might find at some point that the utility company will wish to purchase some of the CCA's lower cost wind power for its customers, too, particularly since SDG&E is required by law to have 20 percent of its electricity supply come from renewables. While an analytical comparison between the GEO portfolio and SDG&E future wholesale power costs is outside the scope of this project, the above discussion shows in principle why CCA's can remain competitive. Reports by Navigant Consulting have demonstrated how nearly every municipality of reasonable size can achieve substantial savings, usually in the tens of millions of dollars or more, by this sort of financial leverage.

In general, our methodology has been to compare the cost of GEO portfolio elements with the comparable electric supply product derived from natural gas power plants owned by private investors. This is the basic method of analysis used by the CPUC, in which the price of natural gas is a benchmark for calculating what a typical generator must charge to recoup its money and make a standard rate of return. This, however, is not necessarily the same as calculating whether an investment will make or lose money. It is an important guideline in California, because so much of our energy comes from natural gas, yet it must not be forgotten that most of the electricity comes from other sources, including renewables. So, the natural gas benchmark cannot be used as the only guide.

An additional factor is that a low carbon portfolio may become a carbon asset, with the ability to sell carbon credits. This could become a significant revenue stream if carbon prices rise, as many analysts expect.

More Local Jobs

Renewable energy systems create several times the level of ongoing employment than fossil fuel generation. This is partly a function of the fact that money is not being expended into high fossil fuel commodity costs that will be lost from the local economy. A 180 MW solar thermal peaking plant can be expected to produce about 70 ongoing jobs, while a large wind farm about 16 employment positions for each 100 megawatts of capacity. Thus a 400 megawatt wind farm would provide about 64 ongoing jobs. The natural gas peaking facility will produce between 15 and 20 jobs while the Pumped Storage facility will produce about 10 jobs. Thus the total direct employment would amount to approximately 164 people. This compares with approximately 22 employees that would be needed to run a 500 to 600 MW natural gas-fired power plant such as the SBRP.[18]

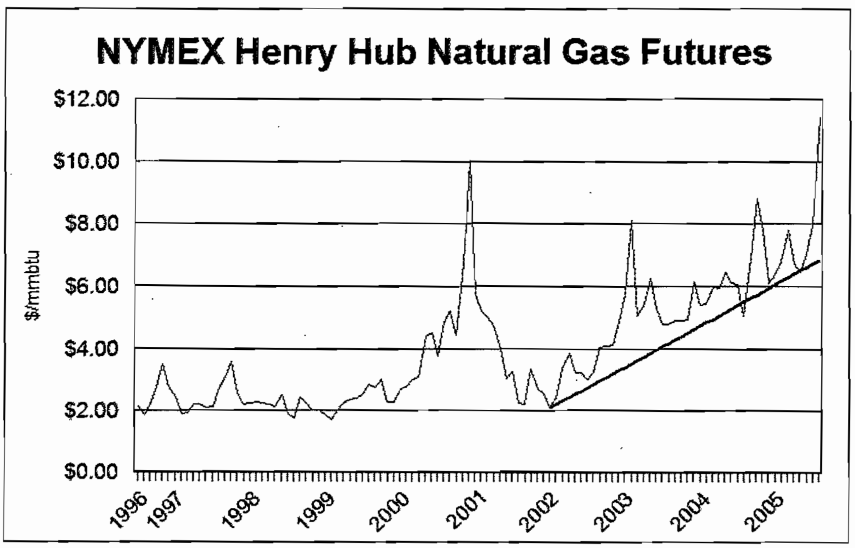
More Money in the Local Economy

The amount of money saved on fuel expenditure is likely to be large, as the investment in renewables is a 20 to 30 year commitment that avoids most of the fuel that would be necessary to produce the same amount of electricity. A new natural gas plant running at the same capacity as the existing SBPP would use about 18.5 million MMBtu/year. This energy content translates into about 18 billion cubic feet of natural gas per year. At a cost of $6 per thousand cubic feet, this represents $110 million of fuel cost per year. Over a 30-year period this would be $2.3 billion worth of fuel, assuming fuel costs were to remain at current levels. Even the most optimistic cost projections do not assume decreasing nominal prices for natural gas, so an increase in fuel cost of about 2% per year or more is reasonable. Since not all the capacity of the plant will be replaced with renewables, the exact[19] amount of fuel savings will depend on the scenario chosen, as well as the future price of natural gas.

Decreased Reliance on Natural Gas

The GEO portfolios provide more energy security than continued heavy dependence on gas-fired power plants. A replacement plant would consume 18 million MMBtu of natural gas per year. The GEO options would use far less than that, about 4-7 million MMBtu per year, and would considerably reduce ratepayer exposure to natural gas price volatility.

Figure 2. New York Mercantile Exchange Futures Prices for Natural Gas.



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[18] Comparative Cost of California Central Station Electricity Generation Technologies, California Energy Commission Staff Report, August 2003, Doc. 100-03-001.

[19] California Energy Commission Staff Report, August 2003. Natural Gas Market Assessment. http://www.energy.ca.gov/reports/2003-08-08_100-03-006.PDF#search=%22natural%20gas%20market%20assessment%22. Accessed October 2006.

Overexposure to one fuel makes SDG&E's monthly electric bill also volatile. In 2000, gas spot-market prices quadrupled in less than nine months peaking in January, 2001. Domestic gas supplies are constrained, yet SDG&E is planning new gas-fired power plants and seeking to obtain the gas via its holding company, Sempra, from overseas. By focusing resources on accelerated renewable energy and conservation development, Chula Vista can reduce ratepayers' exposure to increasingly volatile natural gas prices, and steer away from SDG&E's new dependency on Liquefied Natural Gas imported from overseas at great expense.

Environmental Benefits

The Green Energy Options outlined in this report would provide a number of significant environmental benefits, including improved air quality, environmental justice, and reduced global warming emissions. In this section, we evaluate the operating impacts in these areas of the GEO options compared to the proposed South Bay Replacement Project, and to a load-following natural gas plant.

In comparing the Green Energy Options to natural gas burning plants, it is important to understand that the manner in which a natural gas power plant is run determines its air pollution and greenhouse gas emissions. Like a car, a plant's efficiency will be different if it is run steadily, (as in freeway driving) as opposed to ramping up and down (as in City driving or driving in stop and go traffic). Thus, when we compare air pollution and greenhouse emissions from the Green Energy Options to those from a natural gas plant, we must be clear about what energy needs and market conditions the GEO portfolios and the natural gas plants are designed to meet.

As is explained in Section 3, the GEO portfolios are designed to meet the energy needs currently being met by the South Bay Power Plant. The SBPP runs as a load-following plant that ramps up during periods of high demand, which usually occur from midday through the evening, with highest demand typically needed to meet air conditioning needs on hot summer days. For this reason, we compare the GEO options to a new state of the art load-following natural gas plant, whose energy production 'follows' the daily and seasonal fluctuations in energy demand 'load'.

We also compare the GEO portfolios' environmental impacts to those of the proposed South Bay Replacement Project (SBRP). The SBRP is proposed to be a base-load plant, that is, a plant that runs relatively steadily to meet 24-hour daily energy demand. The plant will, however, have a duct- firing component to it, which would allow a part of the plant's capacity to run more as a load-following or peaker plant. The plant's efficiency is much lower when it is producing energy through duct firing. It is unclear at this point how much duct firing the plant is planning to use, but we have used the best available information on the plant as provided in LS Power's CEC permit application (AFC) to estimate emissions from the SBRP.

The GEO options are designed to meet RMR needs, and provide dispatchable energy on demand. To meet the RMR criteria, the GEO options rely in part on some natural gas capacity that can kick-in when the solar and wind components of the portfolios are unavailable. This is why the GEO portfolios would create some emissions of air pollution and greenhouse gases, though far less than either the current or proposed replacement plant.

Air Quality Benefits

Chula Vista's air quality is currently unhealthy, and particulate matter emissions are a major concern. Levels of particulate matter (PM) measured at the San Diego Air Pollution Control District's Chula Vista monitor exceed state and national air quality standards.[20] While there are many sources of PM – including cars and trucks – a power plant can be a significant source of this pollutant, especially in a localized area near the plant. The manner in which the SBPP is replaced will thus be an important factor in determining future air quality in Chula Vista.

The size of particulate matter from natural gas plants is almost all 2.5 microns or less, which is designated $PM_{2.5}$. $PM_{2.5}$ particles travel deep into the lungs where they can seriously damage lung tissue. They are so small that they can get into the blood stream through the lungs, and carry pollutants that are adsorbed to the particles throughout the body.[21] A battery of studies has linked PM to a number of health hazards, including aggravated asthma and lung disease, decreased lung function, heart attacks and premature death.[22] Natural gas power plants also emit nitrogen oxides (a precursor to ozone or smog) as well as other air pollutants.

The South Bay Power Plant is a major source of air pollution. In 2003 (the most recent year for which a San Diego Air Pollution Control District inventory is available), it emitted nearly 95 tons of particulate matter (PM) and 86 tons of nitrogen oxides (NOx).[23] LS Power, the developer of the South Bay Replacement Project (SBRP) has proposed that the new plant will emit no more pollution than the existing South Bay Power Plant.[24] The California Energy Commission has raised concerns about the methods used in LS Power's CEC permit application to estimate emissions from the existing and proposed plant. It is thus unclear at this point what the actual emissions from the SBRP are likely to be.[25] LS Power has estimated the existing plant's actual PM emissions are at 69 tons per year and the proposed SBRP's maximum emissions to be about 69 tons PM per year. Our estimates put the SBRP's likely emissions at about 94 tons per year, running as a typical base-load plant (at 80% capacity factor) with intermittent duct firing (at 9% capacity factor).

A new plant could emit a comparable amount of pollution as the existing plant because, although the new SBRP will be more efficient than the existing plant, it will be run more often. Therefore, under the current proposal, the West Chula Vista community could see *no improvement* in air quality with the shutdown and replacement of the South Bay Power Plant, and might even see an increase in air pollution.

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20 San Diego Air County Air Pollution District. Monitoring data from the Chula Vista monitoring station 2000-2005. Available at: http://www.sdapcd.org/air/reports/smog.pdf

21 Lipmann, M. et. al. (2003). The U.S. Environmental Protection Agency Particulate Matter Health Effects Research Centers Program: A Midcourse Report of Status, Progress, and Plans. *Environmental Health Perspectives* 111 (8) 1074-1092.

22 US Environmental Protection Agency. Health and Environmental Effects of Particulate Matter http://www.epa.gov/ttn/oarpg/naaqsfin/pmhealth.html. Accessed February 17, 2006.

23 SDAPCD Emission Inventory at http://www.sdapcd.org/toxics/Project1/SourceEmissions.html Accessed 11/8/2006.

24 LS Power. 2006. Application for Certification to the California Energy Commission for the South Bay Replacement Project. Page 8.1-54, Table 8.1-34.

25 CEC Data Requests to LS Power Generation LLC as of October 31, 2006, Docket 06-AFC-3.

If the existing SBPP were to be replaced with a load-following plant that generated a comparable amount of electricity as the existing plant (32% capacity factor), its total PM emissions would be slightly lower than the existing plant's, at about 68 tons per year.[26] The GEO portfolios would only emit from 14 to 27 tons per year.[27] The GEO portfolios would thus emit 60-80 percent less particulate matter than a load-following natural gas plant. The portfolios would emit 70-85 percent less pollution than would the proposed SBRP. (Appendix H)

The air quality *impacts* that are created by a given project's *emissions* are a product of the project's location and other project-specific factors. The SBRP is proposed to be located next door to the existing SBPP on the Chula Vista Bayfront, directly upwind of the residential and densely populated area of West Chula Vista. While it is not clear if any natural gas capacity is needed on the bay, the preferred option would be to have no, or very little, capacity at this site. Nonetheless, even if all the natural gas portions of the GEO portfolios were located at this site, the PM emissions would still be much lower than the SBRP's.

Environmental Justice

For over 40 years, the community downwind of the existing power plant has borne the pollution burden of a facility that serves the energy needs of a good portion of the County. The proposed plant would generate far more electricity than is needed by the City of Chula Vista. Even if we look into future energy demand in Chula Vista, and assume minimal energy efficiency improvements, projected energy demand in the City of Chula Vista is estimated to be 1,345 GWh by the year 2023.[28] The proposed SBRP would produce about 3,600 GWh per year, so West Chula Vista residents would continue to bear the pollution burden for others' energy use.

Locating another large plant near the site of the existing power plant would perpetuate environmental injustice. The community living within a six-mile radius of the South Bay Power Plant is 77% Latino, with 21% of residents closest to the plant living below the poverty level.[29] As does everyone, residents in West Chula Vista deserve healthful air to breathe. Replacing the energy currently being provided by the SBPP with the GEO options would move Chula Vista in the right direction, toward attaining air quality standards and environmental justice.

Reduced Global Climate Change Impacts

The GEO portfolios would avoid significant emissions of greenhouse gases, and reduce the region's contribution to the global climate crisis. The predicted impacts from Global Climate Change are severe. In California, global warming is predicted to create more severe heat, worsened air quality, threatened agriculture, coastal flooding, increased wildfires, and decreased Sierra snow pack which provides water resources to much of the State, among other serious

[26] Assuming a 32% capacity factor and a heat rate of 9,400 MMBtu/kwh, a typical heat rate for a new load-following plant.

[27] Also assuming a 32% capacity factor and a heat rate of 9,400 MMBtu/kwh for natural gas portion of the GEO portfolios.

[28] Navigant Consulting, Study for City of Chula Vista on MEU Feasibility. March 19, 2004. Based on SANDAG growth projections.

[29] Western Chula Vista Revitalization Population, Market, and Housing Trends, City of Chula Vista, Feb 2, 2006, p.9

threats.[30] The GEO portfolios offer Chula Vista and the San Diego region an excellent opportunity to reduce this major threat to our State and the World.

If the proposed SBRP were running as a typical base load plant with intermittent duct firing, it would produce about 1.5 millions tons per year of carbon dioxide (CO_2). A load following natural gas plant would produce about 1.1 million tons/yr of CO_2. In aggregate, the SBRP would produce more carbon dioxide, but per unit of energy produced, the load-following plant would produce about 1100 tons per megawatt hour of electricity produced as compared to about 830 tons/MWh for a base-load SBRP (Appendix H).

The GEO portfolios would emit far less carbon dioxide per year than either the SBRP or a natural gas burning load-following plant: about 220,00-420,000 tons of CO_2 per year. This is 60-80 percent lower than a load-following natural gas plant and 70-85 percent lower than the proposed SBRP. The annual savings in carbon dioxide emissions provided by the GEO portfolios is equivalent to taking 200,000 – 250,000 cars off the road.[31] On a CO_2 emissions per unit of energy basis, the GEO portfolios would also emit far less, with emissions of from 382 to 386 tons of CO_2 per megawatt hour, or about only ⅓ to ½ of the emissions from the exclusively natural gas options.

Chula Vista has been a leader in pursuing local initiatives to reduce the City's contribution to the global climate crisis. In 2000, the City adopted a CO_2 reduction plan as part of its participation in the International Council for Local Environmental Initiatives (ICLEI). This plan directs the City to seek green power purchase options. The City's facilitating the development of the Green Energy Options outlined in this report would set the City firmly on a path to global climate responsibility and leadership.

[30]California Climate Change Center, a project of the State of CA. July 2003. Our Changing Climate, Assessing the Risks to California.
[31]US Climate Technologies Cooperation Gateway, Greenhouse Gas Equivalency Calculator. http://www.usctcgateway.net/tool/ Accessed October 2006.

GEO Report Findings

The Greener Energy Options Portfolios are economically viable

The low cost financing available to a city through municipal bonds can leverage significantly lower cost for renewable generation. Also, the he largely fixed cost of the renewables provides a hedge against substantial risk of increasing natural gas prices over the next 20 to 30 years. There are essentially two scenarios examined here. The first assumes portfolio costs under a 30 year capital or revenue bond, which would optimize cash flow in the earlier years of the investment. This is how the different projects are evaluated as separate investments.

This contrasts with the second scenario examined in the report, a 20 year term investment under a CCA revenue bond, where the cost to own and operate a plant on a per kilowatt-hour basis is significantly higher during the bond period. Once the bond is paid off, however, the capital cost is removed. The result is that, from year 20 to year 30, the only real cost will be operation and maintenance, and possibly some equipment replacement. This will mean very inexpensive overhead, especially when compared to the earlier years, which may amount to only a few cents per kilowatt-hour for peak power generation. The result is that substantial returns on the investment can be made during these "out years", when cost of operation is low and fuel and retail electric rates are likely to be higher than today. It may well be worthwhile for Chula Vista to invest in the capital asset to accumulate an equity position at a rate that preserves the cash flow of the projects during the 20 year CCA revenue bond period. The return on this investment will then be achieved in the out years (year 20 to 30).

A full economic evaluation of a CCA is outside the scope of this report, and would involve base load power supplies, transmission and distribution, and other operating expenses not considered here. These in turn would need to be modeled against expected future SDG&E rates. While some renewables owned by the CCA may cost more than natural gas power plants, this 'higher price" will be offset by similar renewable requirements for SDG&E. Thus it is unlikely that the portfolio considered here would result in any higher cost than for any other customers in the region. In particular, the low cost financing is likely to provide the least cost option for the renewable portion of the portfolio that will significantly offset the compressed timeframe (20 year CCA bond term) for repayment of the assets.

We have used the Market Price Referent (MPR) methodology, derived from the price of natural gas electric generation, as a basis for comparison between GEO energy supplies and to provide a general sense of the viability of an investment. Yet the investments are not taken in isolation; they serve as hedges one against the other. A significant portion of natural gas generation is included for reliability of power supply, but also to take advantage of any drop in natural gas prices. The wind and solar components protect against any increases in the price of natural gas. Losses that may occur in one segment are offset by other parts of the portfolio; and the losses should not be examined in isolation, since a change in market conditions may reverse the loss. In general the natural gas component is designed either to make money on the open market, or save CCA ratepayers on their bills, under all scenarios. That is because, first, the price of natural gas is similar for all generators over the long run, but the CCA has lower cost of money. This locks in a differential with other natural gas generators with which the CCA gas plant is competing.

Second, the plant is intended to operate as a cogenerator, which means that waste heat is capture and sold at or below cost. Most commercial power plants do not operate in this way, and older cogeneration plants will be less efficient than a modern one. Thus the CCA natural gas plant can provide a double revenue stream, while conserving natural gas.

The GEO Portfolios offer significant benefits

As is detailed in the preceding section, the GEO portfolios offer a number of benefits over a gas-fired plant. The GEO portfolios would result in 60-80 percent less emissions of particulate matter air pollution and would promote environmental justice. The GEO options would also produce more local jobs, decrease the region's over-reliance on natural gas, and keep more money in the local economy. Pursuing the GEO options would get us firmly down the road of a more secure and sustainable energy future for the region, and would lessen the region's contribution to the global climate crisis.

The initiative must be led by Chula Vista

Over the past four years, the City of Chula Vista has prepared extensively for the implementation of Community Choice Aggregation ("CCA") and/or development of green and renewable power generation facilities. CCA would allow Chula Vista to find an alternative electricity supplier to SDG&E, and to decide what kinds of electricity to purchase. In addition, municipalities and other local public agencies like Chula Vista may issue municipal revenue bonds ("H Bonds") to finance renewable energy and conservation facilities. These mechanisms will be analyzed in this Plan.

A strong argument can be made that CCA in conjunction with H Bonds allows the greatest potential for cost-effective, cleaner and more sustainable replacement of the South Bay Power Plant ("SBPP"):

- First, as a Community Choice Aggregator (CCA), Chula Vista would be poised to solicit competitively priced power from competitive suppliers for its residents, businesses, and municipal facilities.[32]

- Second, Chula Vista may profitably develop a revenue-producing renewable energy facility with pumped storage or gas-fired facilities for capacity balancing. Using the unique leverage that municipal revenue bonds and CCA facilitates, it is now possible to serve Chula Vista residents, businesses, and public agencies with this qualitatively superior, greener, more reliable energy source. New, city-owned, facilities could generate electricity, at rates equal to or lower than SDG&E's rates, both for local use and profitable sale of excess power in wholesale markets or to other public agencies. As stated above, this level of analysis is beyond the scope of this report. However, the conclusion is supported by the fact that both the CCA and SDG&E will require a substantial renewable portfolio, and the CCA has at its disposal a significantly lower cost for capital that places it at a significant advantage. In addition, if the city elects to sell power, it will be able to command a market price comparable to private vendors, and any

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[32] Chula Vista commissioned Navigant Consulting to prepare a Feasibility Study on CCA in Chula Vista, conducting peer review with several public hearings.

"over market" costs (i.e. costs above natural gas generation) will thus be rate-based for SDG&E customers, since SDG&E will need to meet its renewable obligation.

This report identifies several specific opportunities available to Chula Vista, with a variety of locally feasible technologies and partnerships. However, even if CCA is not pursued by Chula Vista, other governance structures and initiative options are available for the City to pursue some or all of the green energy options outlined in this report

Community Choice Aggregation (CCA) and Public Investment is the best Approach

Unless Chula Vista forms a CCA, any transmission facilities must either be owned by SDG&E or some other transmission entity such as a Tribal Government. The City of Chula Vista signed a 20-year franchise agreement with SDG&E in 2004 committing *"that the City will not participate in the provision of electric or natural gas Distribution Services by itself or others within its jurisdictional boundaries for the term of the franchises."* Thus, Chula Vista may not sell "distribution" services to consumers. The MOU defined "distribution" as *"the ownership and/or operation by the City itself, or with or by any third party, of any facilities, including pipes, wires, and electric and gas utility plant and related services for the transmission or distribution delivery of electricity or natural gas to consumers within the boundaries of the City of Chula Vista."* The MOU excluded from this rule the *"performance of (i) those rights and duties specific to Community Choice Aggregation...within or outside CITY limits if authorized and as approved and implemented by the CPUC, if such is required or (ii) generation of electric power."*[33]

However, a CCA and renewable generation project would enjoy a full range of options. Thus, if Chula Vista forms a CCA or builds a power generation facility, it may elect to sell transmission services within or outside Chula Vista. There are at least two options to accomplish this.

The first option is to develop future renewable energy and conservation facilities that require transmission service by taking action to:

- Acquire access to existing transmission capacity;
- Arrange with SDG&E to provide transmission access, pursuant to Federal Energy Regulatory Commission (FERC) Order 888, or;
- Arrange to purchase transmission services from another party such as a tribal government.

The second, and probably more important, option is to develop local power resources that require little or no transmission facilities to deliver the power to customers. As this report will show, the Chula Vista region offers opportunities to develop a large solar concentrator and other renewables in the immediate Chula Vista and neighboring areas interested in participating in the development of the facilities and/or the purchase of power from such facilities.

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[33] Memorandum of Understanding Between San Diego Gas & Electric Company and the City of Chula Vista, October 12, 2004, p. 11, Section 1.14.A.

Both options are more local in nature than the power supply now being provided to residents and businesses in Sempra's service territory. Both options are financially feasible at competitive wholesale and retail prices, with either a CCA or a city-owned merchant facility, or both, being the structuring principle of the project.

CCA is by far the best way to ensure success and achieve the kind of scalability needed to physically alter the need for generation in this part of the electric grid. Photovoltaics (PV) on Chula Vista rooftops, energy efficiency, demand response may be fundable with existing ratepayer funds if a CCA is formed and the opportunity to administer the funds is requested at the California Public Utilities Commission.[34]

Other distributed generation may be undertaken within the City under a CCA or a revenue bond funded ("H Bond") program, and may invest General Funds in renewable energy projects for non-CCA customers if the City wishes to operate the plant as a public enterprise. Because scaled projects such as those presented in this Plan are necessary to eliminate multi-hundred Megawatts of regional demand in order for the Independent System Operator (CAISO) to accept a downscaling of new power generation on the South Bay site, this report identifies several physically viable, legally developable and economically competitive green power facilities, estimates facility costs, schedules for payback and power pricing. Specific facility scales in each Scenario are based on a variety of potential market structures, including Community Choice Aggregation (CCA) the use of H Bonds, and potentially available state of California funding for energy efficiency programs pursuant to the Community Choice law, AB117[35].

The ability to eliminate or reduce the need for power generation at the South Bay Power Plant site depends on the municipality's degree of public investment, as well as investment by potential strategic partners in the region. This investment may be structured as follows:

- Municipal Enterprise. Chula Vista can meet their interest in an entrepreneurial energy venture by owning renewable energy and conservation facilities as a municipal enterprise while also meeting its mandate for first-class environmental leadership;
- Creation of a CCA adds even larger-scale private sector purchasing power to public financing, enables a commensurate scaling-up of renewable energy development, and provides a secure revenue stream for the H Bonds that the city and/or its other public partners elect to issue for solar photovoltaics and the other locally feasible investments in the Chula Vista area and East County;
- Chula Vista investment in renewable energy and conservation facilities involves a lower degree of municipal risk than investment in a 100% natural gas generation power plant, because there is reduced exposure to the highly volatile price of natural gas that constitutes 50% to 80% of the life cycle cost of a gas-fired power plant.

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34 CPUC Proceeding R.01-08-028.

35 Migden, 2002

Such investments can provide benefits including:

- As free-standing investments, any profits realized from renewable energy or conservation facilities, they can benefit taxpayers by contributing funds to the City of Chula Vista General Fund.
- If the renewable energy or conservation facilities are incorporated into a CCA, then they can realize long term savings for ratepayers compared to market prices for similar energy supply.
- Renewable and conservation facility assets will retain their market value and generate revenue for decades after H Bonds or other financing are repaid, offering both returns on public investment and a lower cost of energy for local residents and businesses.

The GEO Portfolios are consistent with existing local, state and federal policy, regulations, and law

All alternatives proposed in this Alternative Energy Plan meet the stated project objectives in the AFC for the South Bay Replacement Project. These are:

- Commercially-viable and capable of supplying economical electrical services – capacity, reliability, ancillary services, and energy supply – to the San Diego Region.
- Capable of ensuring the timely removal of the existing South Bay Power Plant and that fulfills the obligation found in Article 7.1.a of the Cooperation agreement, which states, "*use commercially reasonable efforts to develop, finance, construct and place into commercial operation a new generation plant replacing the South Bay Power Plant...which shall have a generating capability at lease (sic) sufficient to cause the ISO to terminate (or fail to renew) the must run designation application to the South Bay Power Plant on or before termination of the lease*" [36] and upon which the size of replacement power is based.
- Meets applicable laws, ordinances, regulations, and standard (LORS) of the California energy Commission, Chula Vista, the Unified Port of San Diego and other agencies, and complies with the Applicant's Environmental Policy.
- Consistent with the objectives, guidelines and timing goals of the emerging Bay Front Master Plan.
- Assists in maintaining and/or increasing the regional electrical systems' efficiency and reliability.

[36] LS Power. 2006. Application for Certification for the South Bay Replacement Plant, footnote 5, page 1-7

- Supports attainment of the state-mandated 20 percent Renewable Portfolio Standard (RPS) requirements for renewable energy, which will be required if a Chula Vista CCA is formed.[37] The renewable generation could also support SDG&E to achieve compliance with its RPS requirements under potential power purchase agreements.

- The GEO options would have a lower cost of electric generation over the life of the assets than if Chula Vista CCA or SDG&E were to purchase similar legally required renewable power supplies on the open market, due to the low cost of municipal financing. This meets one of the key requirements of state regulation (CPUC) that electric generation resources be "least cost".

- The GEO options can replace the function of the current plant, to provide urgently needed power during times of peak demand, when the stability of the electric grid is most at risk. The proposed "all natural gas" replacement on the bayfront would achieve this to a much smaller degree, since it is mainly designed to supply 24 hour a day base load. Thus, the GEO meets the other key requirement of the CPUC that electric generation resources be "best fit".

[37] Application for Certification for the South Bay Replacement Plant, page 1-7

Recommendations

- Chula Vista should present evidence to the ISO and other regulatory bodies, proving why a replacement for the current plant is not needed on the Bayfront. ***This report shows that about 2000 megawatts of alternative options exist within San Diego County***, some of which would cost far less than replacement of the South Bay Power Plant at its current site. In some cases merely changing regulatory status or evaluation of existing or planned resources, or the need for them, is all that is required. It is unlikely that replacement of more than a fraction of the current plant is really necessary to meet the needs of the region for years into the future. That is the most important reason why a range between 50% and 90% replacement of existing capacity has been proposed in this report.

- Chula Vista should further investigate the options identified in this report to begin discussions with potential site owners, financing sources and partners for different projects. Scoping needs to move as soon as possible to the next level of specificity to answer critical questions.

- Chula Vista should fund and prepare an Implementation Plan and draft a Request for Proposals for Community Choice Aggregation and H Bonds that includes designing, building, operating and maintaining a solar concentrator, wind and pumped storage facility in conjunction with local solar photovoltaics, distributed generation, energy efficiency and conservation. These measures should be supplemented with natural gas fired co-generation to balance out the portfolio risk and energy costs, as well as to insure the full reliability requirements are met.

- Chula Vista should only entertain sites for facilities that minimize the need for new transmission, and only allow transmission that is placed on existing rights of way. Any new lines should be occupied only by clean energy capacity. No major power lines on new corridors are needed, as they will impose billions of dollars in costs on ratepayers as well as make the region even more dependent upon energy imports. These imports send dollars and jobs out of the region while new transmission corridors would spoil the county's landscape and natural beauty.

- Chula Vista should participate in the ISO RMR designation to ensure the RMR is calculated appropriately to include all renewable and other green energy sources.

- Chula Vista should participate actively at the California Energy Commission, Independent System Operator (CAISO), California Public Utilities Commission, and Federal Energy Regulatory Commission to propose the options identified in the GEO as preferable to repowering the South Bay Power Plant site.

- At present two of the largest generating plants in the region, representing nearly 1000 megawatts of capacity, contribute nothing to grid reliability, according to ISO evaluation.

San Onofre Nuclear Generating Station is not counted at all toward regional generation, even though it supplies over 400 megawatts of power, 24 hours a day, to San Diego County. That is because it uses up capacity on the same transmission line that is used for importing electricity. And the new Palomar plant, at over 500 megawatts, does not count either due to a mere technicality. Chula Vista should urge the ISO, CEC and CPUC to move forward with assuring that the Palomar power plant is fully accounted for as reliable generation capacity, and that a short transmission line be added to the existing South of SONGS (SOS) corridor to connect the plant directly to the regional grid without casting a transmission shadow for electricity imports from the north. These two tasks would together supply approximately 500 megawatts of additional reliable capacity to the region for by far the least cost and environmental impact.

- Chula Vista should challenge the "bait and switch" tactic of justifying a new 24-hour a day "all natural gas" powered base-load replacement plant on the bay, based upon the ISO reliability contract on the existing plant. The current plant is considered necessary for meeting peak demand when power is urgently needed for grid stability, and only runs its generators part-time. The function of the current plant is completely different from the one proposed to replace it, and should require a separate evaluation of need.

- Chula Vista and other local and regional land use authorities should adopt stringent building standards that maximize energy efficiency, demand response, and development of clean, renewable energy sources integral to new and renovated building construction.

Appendices

List of Tables in Appendices

Appendix A Cost Factors for a Wind Farm

The cost of wind power has dropped from a range of 30 to 50 cents per kilowatt hour in the early 1980s to between 5 and 8 cents per kilowatt hour today. This is now competitive with other forms of electric generation, especially natural gas and nuclear power. On the low end of its price range wind may even compete with new coal plants, due to pollution control requirements, and long term risk of carbon emission liability.

There are three key factors that determine the cost of the electricity generated from wind power: the installed cost of the wind farm, the financing cost, and the wind resource. The installed cost of wind farms was between $1000 and $1200 per kilowatt in 2003; however a few factors have combined recently to increase that cost. The unpredictable US production tax credit for wind causes a "boom and bust" cycle in demand for wind turbines in this country. The credit has been in effect for the last two years, which has pushed up demand to historical highs with a new wind farm being built every two to four weeks. In fact, far more wind than coal capacity is currently being added.

State policies requiring utilities to put renewable electricity sources into their portfolios, as well as increases in the price of natural gas and higher retail electric rates, has helped drive growth in wind power. In the late 1990s only a few hundred megawatts of wind were installed each year in the US; this reached 2431 megawatts in 2005 and 2454 megawatts of new capacity was added in 2006. Manufacturers can barely keep up, and most production capacity is reserved in advance for the next two years. Increased demand, higher raw material prices, and the low value of the dollar have caused the price of wind turbines to go up. The result is that wind farms in the US now range from $1300 to $1750 per kilowatt. We project a lower end cost, assuming that the project will be well planned, and that the current overheated market will cool as manufacturing capacity catches up to demand.

There are important factors that can offset this recent trend. The cost of the tower and turbine is only about half the installed cost, which also includes labor, access roads, power lines, etc. Thus, even a 50% increase in material costs will result in a smaller impact on a total project.

Manufacturers are also helping in important ways. The size of individual wind turbines is increasing, which lowers unit costs. Efficiency and performance of wind turbines is steadily increasing year by year. This is a function of improved design, careful measurement of wind resources, and better placement of wind turbines. The effect has been dramatic. The electric generation from a given sized wind farm has increased by more than 50% since the early 1980s. There have also been great improvements in quality and durability, with the result that wind turbines need less servicing, and are available 98% of the time for generating electricity.

An opportunity may come for Chula Vista when the Federal wind tax credit expires, and the city should prepare to take advantage if a window opens up. The tax credit is paid to private investors in wind farms, based on the electric generation of the facility, at the rate of 1.9

cents per kilowatt hour presently, but this is indexed to inflation; we project a rate of 2 cents/kwh by 2009 if the credit is reinstated. Since government entities do not get tax credits, Chula Vista is not dependent on the credit to make wind power an attractive investment. The low-interest financing from municipal bonds can bring the cost of wind power to an even lower level than a private investor would achieve with the support of the credit, Because the private investor's tax credit expires after the first ten years of the project's operation, a municipal owner of a wind farm has a long term competitive edge over other owners.

The value of low cost financing is substantial. A 400 Megawatt wind farm installed at the rate of $1350 per kilowatt will cost $480 million. A private investor that has an average cost of capital of 11.8% will incur about $1.9 billion in expenses to cover interest on borrowed funds and profit for investors over a 30 year period. By comparison, a publicly financed wind farm need not provide any profit for investors, and is only obligated to repay the bond principal and interest. At 5.25 percent interest over 30 years this will cost about $850 million. *The low-interest municipal financing saves over $1 billion dollars over the 30 year period, far more than the entire installed cost of the wind farm. This demonstrates the huge effect of low cost borrowing on renewable generation sources like wind, and why there is a unique opportunity for municipalities.*

At the time when other investors will be leaving the market, municipalities will retain their low cost financing advantage. This places them in a unique position when tax credit expires to take advantage of any price reductions in wind farms.

Wind resource is also vitally important for project viability. The East County has class 5 and class 6 winds. By placing a wind farm in the higher class region, a significant improvement is performance is very likely. Improving the output of a wind farm from a 32% operational capacity (capacity factor) to 35% would reduce the cost of the electricity generated and achieve a more rapid payback on investment. It also increases the cost threshold for a viable project.

Maintaining a high capacity factor is important for economic viability not only of the wind farm but also of the pumped storage portion of the facility. The cost assumption for the pumped storage of $1000 per kilowatt is conservative to high if an existing reservoir is used, but may be low if a new reservoir must be built. We recommend using existing reservoirs in the San Diego region, of which there are several. The given price is the maximum that would make the proposition viable for a CCA, thus it is only likely to make sense as an investment if an existing reservoir is used. There are also considerable environmental advantages when compared to building a new reservoir, creating an alignment between environmental and economic goals.

Table A-1. Wind Cost Summary

	Private Investor	Chula Vista/ municipality
Installed Cost Rate	$1350 per kilowatt	$1350 per kilowatt
Tax Credit	2 cents/kilowatt hour, first 10 years	none
Financing Cost	11.8%	5.25%
Economic Lifecycle	30 years	30 years
Wind Class	6	6
Operation / Capacity	35%	35%
Cost per kilowatt-hour	7.4 cents/kwh	4.8 cents/kwh
1st 10 year cost after credit	5.4 cents/kwh	not applicable
Electricity sale price (initial)	5.2 cents/kwh	4.8 cents/kwh
Simple Payback	8 years	9 years

Table A-2. Wind Farm Electric Generation Cost with Private and Public Financing

Levelized Cost Analysis in Class 6 Region*

Private Finance			**Public Finance**		
11.8% Avg. Cost of Capital; 2 cent/kwh Production Tax Credit.			Bond financing no tax credits		
Capital Cost:			Capital Cost:		
Installed Cost Rate	$1,350	per kw	Installed Cost Rate	$1,350	per kw
Capacity	400,000	kw	Capacity	400,000	kw
Total Cost	$540,000,000		Total Cost	$540,000,000	
Tax Credit	0%		Tax Credit	0%	
Net Cost	$540,000,000		Net Cost	$540,000,000	
Utility Finance:			Public Finance:		
Avg. Cost of Capital	11.8%		Bond Rate	5.25%	
Term	30	yrs	Term	30	yrs
Financing Cost	$1,911,600,000		Financing Cost	$850,500,000	
Operation and Maintenance:			Operation and Maintenance:		
Personnel	64		Personnel	64	
Assumed avg. Salary	$55,000		Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,520,000		Annual Personnel Cost	$3,520,000	
Maintenance &other rate/capital-yr.	1.6%		Maintenance &other rate/capital-yr.	1.6%	
Maintenance & other cost/year	$8,640,000		Maintenance & other cost/year	$8,640,000	
Annual O&M	$12,160,000		Annual O&M	$12,160,000	
Lifecycle O&M	$364,800,000		Lifecycle O&M	$364,800,000	
Electric Generation:			Electric Generation:		
Capacity Factor	35%		Capacity Factor	35%	
Generation rate	3,066	kwh/kw	Generation rate	3,066	kwh/kw
Gross Annual generation	1,226,400,000	kwh	Gross Annual generation	1,226,400,000	kwh
Parasitic Load factor/loss	0.1%		Parasitic Load factor/loss	0.1%	
Annual Loss	1,226,400	kwh	Annual Loss	1,226,400	kwh
Net Annual Output	1,225,173,600	kwh	Net Annual Output	1,225,173,600	kwh

Private Finance

Electric Generation Cost:		
Lifecycle Cost	$2,816,400,000	
Lifecycle Output	36,755,208,000	kwh
Avg. O&M rate	$0.010	
Cost of Electricity	**$0.077**	per kwh
Production Tax Credit (2009)	$0.020	per kwh
Net first 10 year cost	$0.057	per kwh
Wind Purchase Price	$0.052	per kwh
Generation per year	1,225,173,600	kwh
Annual Avg. revenue	$63,709,027	
Annual Avg. Cost	$93,880,000	
Annual Avg. Cost first 10 years	$69,376,528	
Simple Payback Wind	8.48	yrs

Public Finance

Electric Generation Cost:		
Lifecycle Cost	$1,755,300,000	
Lifecycle Output	36,755,208,000	kwh
Avg. O&M rate	$0.010	
Cost of Electricity	**$0.048**	
Production Tax Credit	$0.000	
Net first 10 year cost	$0.048	
Sales from Wind Farm		
Wind Wholesale Price	$0.052	
Direct sales per year	664,533,600	kwh
Annual revenue from Direct Sales	$34,555,747	
Sales rate to Pumped Storage	$0.048	
Sales to Pumped Storage	560,640,000	kwh
Annual Income from Pumped Storage	$26,774,203	
Total Wind Farm Annual Revenue	$61,329,950	
Annual Operating Cost	$58,510,000	
Annual Wind Farm Net	$2,819,950	
Simple Payback Wind	8.80	years

*Levelized cost does not show the time-dependent changes in O&M cost for wind farms.

Appendix B Solar Thermal w/ Natural Gas and Cogeneration

The cost of solar thermal power has decreased in the last two years, and there is general agreement that it will continue to drop. Current cost of solar thermal generation can range between 13 and 25 cents per kilowatt-hour, depending on scale of the installation, financing and availability of tax breaks. Private developers can take a generous 30% tax credit until 2008, which will revert to 10% unless the higher credit is further extended.

DOE projects that solar thermal electric generation will fall to about 4 cents per kilowatt-hour within a decade, but Local Power considers this projection too optimistic. Those in the industry currently consider it reasonable to expect that the price will fall below 10 cents per kilowatt-hour, a range that will make solar thermal potentially cost competitive with the peak power generated by natural gas power plants.

The first spreadsheet analyzes the cost and performance of a Concentrating Solar Thermal power plant. The first column shows the economics of a privately financed facility to allow comparison with a publicly financed one. The proposed solar thermal project would have about 10% to 15% lower solar resource than the recently developed solar thermal plants in Nevada and Arizona if located in the East County, and 20% to 25% lower if placed in the vicinity of Chula Vista. It would also not be eligible for a tax write-off due to the fact that it would be owned by a municipality. Countering this disadvantage is the much lower cost of capital, which is only the interest payment on the bond. Recycling the heat through a cogeneration system will bring the cost down further.

The net cost to produce a kilowatt-hour, and the profitability of the plant, is significantly influenced by the efficiency with which the heat can be recycled. The assumption is only 50% of the waste heat can be recovered and sold at prevailing energy rates. This is very conservative, as such systems can achieve 75% to 80% recovery on the high end. If the recovery is efficient enough, then the heat can be sold at a discount to make the proposition attractive to a commercial venture.

A solar thermal plant's economic viability is to a large extent locked in at the time of purchase. Unlike a natural gas power plant, very little of the long term cost is bound up in fuel. The major expense is the purchase cost itself, and the cost of financing. Whether this will be competitive with natural gas peak power depends on the future cost of natural gas. The second sheet shows the breakeven costs for the solar plant assuming a range of average prices for natural gas. In this sheet, the assumption is that the plant is financed over a 30 year period by a capital bond as a "self supporting" investment.

Table B-1. Concentrating Solar Thermal Power

Private Finance, 2010 to 2015			Public Finance, 2010 to 2015			Public Finance, 2010 to 2015		
w/ tax credit & 11.5% Cost of Capital			**w/no tax credit & 5.25% 30 year municipal bond financing**			**w/no tax credit & 5.25% 30 year municipal bond financing**		
Reference Natural Gas Price			**Reference Natural Gas Price**			**High Natural Gas Price Scenario**		
Capital Cost:			Capital Cost:			Capital Cost:		
Installed Cost Rate Target	$2,500	per kw	Installed Cost Rate Target	$2,500	per kw	Installed Cost Rate Target	$2,500	per kw
Capacity	160,000	kws	Capacity	160,000	kws	Capacity	160,000	kws
Total Cost	$400,000,000		Total Cost	$400,000,000		Total Cost	$400,000,000	
Tax Credit (enter 10% or 30%)	10%		Tax Credit	0%		Tax Credit	0%	
Net Cost	$360,000,000		Net Cost	$400,000,000		Net Cost	$400,000,000	
Private Finance			Public Finance:			Public Finance:		
Avg. Cost of Capital	11.8%		Bond Rate	5.25%		Bond Rate	5.25%	
Term	30	years	Term	30	years	Term	30	years
Financing Cost	$1,274,400,000		Financing Cost	$630,000,000		Financing Cost	$630,000,000	
Operation and Maintenance:			Operation and Maintenance:			Operation and Maintenance:		
Personnel	70		Personnel	70		Personnel	70	
Assumed avg. Salary	$55,000		Assumed avg. Salary	$55,000		Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,826,087		Annual Personnel Cost	$3,826,087		Annual Personnel Cost	$3,826,087	
Maintenance &other rate/capital-yr.	0.6%		Maintenance &other rate/capital-yr.	0.6%		Maintenance &other rate/capital-yr.	0.6%	
Maintenance & other cost/year	$2,400,000		Maintenance & other cost/year	$2,400,000		Maintenance & other cost/year	$2,400,000	
Annual O&M	$6,226,087		Annual O&M	$6,226,087		Annual O&M	$6,226,087	
Lifecycle O&M	$186,782,609		Lifecycle O&M	$186,782,609		Lifecycle O&M	$186,782,609	
O&M per kwh	$0.021		O&M per kwh	$0.021		O&M per kwh	$0.021	

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

Solar Electric Generation:		
Capacity Factor	23%	
Generation rate	2,015	kwh/kw
Gross Annual generation	322,368,000	kwh
Parasitic Load factor/loss	8%	
Annual Loss	25,789,440	kwh
Net Annual Output	296,578,560	kwh
Solar 'Electric Generation Cost:		
Lifecycle Cost	$1,861,182,609	
Lifecycle Output	8,897,356,800	kwh
Cost of Solar Electricity	**$0.209**	per kwh
Gas Electric Generation:		
Capacity Factor	11%	
Generation rate	964	kwh/kw
Gross Annual generation	154,176,000	kwh
Fuel Cost	$6.50	per MMBtu
heat rate	9400	btu/kwh
efficiency	0.36	
annual energy input	1,449,254	MMBtu
annual energy cost	$9,420,154	

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

Reference Natural Gas Price

Solar Electric Generation:		
Capacity Factor	23%	
Generation rate	2,015	kwh/kw
Gross Annual generation	322,368,000	kwh
Parasitic Load factor/loss	8%	
Annual Loss	25,789,440	kwh
Net Annual Output	296,578,560	kwh
Solar 'Electric Generation Cost:		
Lifecycle Cost	$1,216,782,609	
Lifecycle Output	8,897,356,800	kwh
Cost of Solar Electricity	**$0.137**	per kwh
Gas Electric Generation:		
Capacity Factor	11%	
Generation rate	964	kwh/kw
Gross Annual generation	154,176,000	kwh
Fuel Cost	$6.50	per MMBtu
heat rate	9400	btu/kwh
efficiency	0.36	
annual energy input	1,449,254	MMBtu
annual energy cost	$9,420,154	

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

High Natural Gas Price Scenario

Solar Electric Generation:		
Capacity Factor	23%	
Generation rate	2,015	kwh/kw
Gross Annual generation	322,368,000	kwh
Parasitic Load factor/loss	8%	
Annual Loss	25,789,440	kwh
Net Annual Output	296,578,560	kwh
Solar 'Electric Generation Cost:		
Lifecycle Cost	$1,216,782,609	
Lifecycle Output	8,897,356,800	kwh
Cost of Electricity	**$0.137**	per kwh
Gas Electric Generation:		
Capacity Factor	11%	
Generation rate	964	kwh/kw
Gross Annual generation	154,176,000	kwh
Fuel Cost	$10.00	per MMBtu
heat rate	9400	btu/kwh
efficiency	0.36	
annual energy input	1,449,254	MMBtu
annual energy cost	$14,492,544	

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$282,604,608	
Combined Cost of Solar/Natural Gas Generation		
Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$2,143,787,217	
Combined Cost of Electricity	**$0.159**	
Thermal Energy		
annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu
Cost of Electricity Using Cogeneration		
cogen heat repurchase rate	$6.50	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

Reference Natural Gas Price

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$282,604,608	
Combined Cost of Solar/Natural Gas Generation		
Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$1,499,387,217	
Combined Cost of Electricity	**$0.111**	
Thermal Energy		
annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu
Cost of Electricity Using Cogeneration		
cogen heat repurchase rate	$6.50	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

High Natural Gas Price Scenario

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$434,776,320	
Combined Cost of Solar/Natural Gas Generation		
Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$1,651,558,929	
Cost of electricity	**$0.122**	
Thermal Energy		
annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu
Cost of Electricity Using Cogeneration		
cogen heat repurchase rate	$10.00	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

total lifecycle heat	40,390,219	MMBtu
total economic value	$262,536,422	
net electric cost	**$0.139**	per kwh
Electricity Wholesale Price/MPR	$0.095	per kwh
Generation per year	450,754,560	kwh
Annual Sales	$42,866,759	
simple payback	9.3	years
Financial Cycle Balance	-$595,248,035	
Annual Net	-$19,841,601	
30 Year Net	-$595,248,035	
generation fuel output cost	$0.061	
with mpr capital and variable cost	$0.095	$0.034

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

Reference Natural Gas Price

total lifecycle heat	40,390,219	MMBtu
total economic value	$262,536,422	
net electric cost	**$0.091**	per kwh
Electricity Wholesale Price/MPR	$0.095	per kwh
Generation per year	450,754,560	kwh
Annual Sales	$42,866,759	
simple payback	9.3	years
Financial Cycle Balance	$49,151,965	
Annual Net	$1,638,399	
30 Year Net	$49,151,965	
generation fuel output cost	$0.061	
with mpr capital and variable cost	$0.095	$0.034

Public Finance, 2010 to 2015

w/no tax credit & 5.25% 30 year municipal bond financing

High Natural Gas Price Scenario

total lifecycle heat	40,390,219	MMBtu
total economic value	$403,902,188	
net electric cost	**$0.092**	per kwh
Electricity Wholesale Price/MPR	$0.128	per kwh
Generation per year	450,754,560	kwh
Annual Sales	$57,696,584	
simple payback	6.9	years
Financial Cycle Balance	$483,240,769	
Annual Net	$16,108,026	
30 Year Net	$483,240,769	
generation fuel output cost	$0.094	
with mpr capital and variable cost	$0.128	$0.034

Appendix C Natural Gas Costs

Table C-1 uses DOE projections for natural gas prices until 2030, and extrapolates these to 2040, showing fixed 2004 dollars as well as the corresponding higher nominal inflated dollar equivalent. This places natural gas at a nominal average of $10 per MMBtu between 2009 and 2040, which we use as a HIGH natural gas price scenario. The BASE CASE price is set at $6.50 per MMBtu, while the LOW CASE is $5.00 per MMBtu. We see this as conservative, particularly for a date range running from 2010 to 2040. It is important to take into account this conservative basis when evaluating the investments in the renewable portfolio, as this offers opportunity to profit from upside natural gas risk. Since a significant part of the portfolio is also tied to natural gas, any decreases in natural gas prices will partly offset the renewables that would become relatively more expensive. On the other hand, if natural gas prices rise above current levels, as reflected in the base case, then the renewables will be the lower cost investment. Diversification of the portfolio leads to a double hedge.

The gas price figures are input into a model for electric generation cost for a peaking plant, assuming a heat rate of 9400 Btu per kilowatt-hour for a simple cycle combustion turbine. Variable and fixed costs are set for a plant that operates at 32% capacity factor.

A higher natural gas price will tend to favor renewable facilities, making these investments into natural gas price hedges, as they lock in the cost of generating electricity just as a fuel futures contract would. The difference, however, is that renewables provide this hedge out to 30 and 50 or more years, much longer than any available natural gas contract. By this time, it is expected that the US may face serious depletion of natural gas fuel. Facilities that either do not rely on natural gas, or that rely on it minimally, will be at a great advantage.

Tables C-2 through C-4 compare a variety of natural gas plant investments. The current plant is relatively cheap to run, (with the exception of unit #4), because the capital expense is mostly paid off. A newer peaking plant is not necessarily much more efficient in fuel consumption, as heat rates for simple cycle combustion turbines range from about 9000 Btu/kwh to 10,000 Btu/kwh, with the higher end quite close to the existing plant. For this reason, a new natural gas plant is not likely to avert any future fuel consumption or expense.

The economics of a peaking plant is only partly determined by the heat rate. More important is how many hours per year it is run. The fewer the hours, the more expensive the power, since capital cost becomes more important than fuel as capacity utilization drops. A simple cycle plant is modeled here, because the report examines a functional replacement for the current plant. However, it would be possible to purchase a combined cycle plant with baseload or multiple functionality.

The other major factor is financing cost, as for the renewables. The CCA, using low cost bonds, is at a great advantage in this regard, and can use the natural gas peaker to offset some of the potential near term losses for the fixed cost, renewable generators. Tables C-5 and C-6 show the cost of operating a natural gas peaker plant under private and CCA ownership at low, base, and high natural gas price projections.

Table C-1. Natural Gas Price Projections to 2040

in dollars per million btu

Year	*delta*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*
NG for electric power; 2004 dollars	0.30%	$5.81	$6.07	$8.29	$7.43	$6.71	$6.38	$5.92	$5.60	$5.40	$5.38	$5.49	$5.41	$5.21
Nominal dollars		$5.66	$6.07	$8.50	$7.77	$7.16	$6.96	$6.60	$6.38	$6.30	$6.44	$6.73	$6.80	$6.70
Heat rate		9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400
efficiency		36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%
generation fuel output cost		$0.053	$0.057	$0.080	$0.073	$0.067	$0.065	$0.062	$0.060	$0.059	$0.061	$0.063	$0.064	$0.063
with capital and variable cost	$0.034	$0.087	$0.091	$0.114	$0.107	$0.101	$0.099	$0.096	$0.094	$0.093	$0.095	$0.097	$0.098	$0.097
Consumer price index														
GDP Chain-Type Price Index (2000=1.000)	2.00%	1.063	1.091	1.119	1.141	1.164	1.189	1.216	1.242	1.273	1.306	1.338	1.370	1.404
2004 index		0.974	1.000	1.026	1.046	1.067	1.090	1.114	1.139	1.167	1.197	1.226	1.256	1.287

Year	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*
NG for electric power; 2004 dollars	$5.19	$5.23	$5.40	$5.54	$5.53	$5.66	$5.73	$5.79	$5.90	$6.02	$6.08	$6.17	$6.21
Nominal dollars	$6.83	$7.05	$7.46	$7.85	$8.03	$8.42	$8.74	$9.04	$9.42	$9.84	$10.16	$10.55	$10.86
Heat rate	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400
efficiency	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%
generation fuel output cost	$0.064	$0.066	$0.070	$0.074	$0.075	$0.079	$0.082	$0.085	$0.089	$0.092	$0.096	$0.099	$0.102
with capital and variable cost	$0.098	$0.100	$0.104	$0.108	$0.109	$0.113	$0.116	$0.119	$0.123	$0.126	$0.130	$0.133	$0.136
Consumer price index													
GDP Chain-Type Price Index (2000=1.000)	1.436	1.471	1.508	1.546	1.584	1.624	1.663	1.703	1.742	1.783	1.824	1.866	1.909
2004 index	1.316	1.348	1.382	1.417	1.452	1.488	1.525	1.561	1.597	1.634	1.671	1.710	1.749

Year	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*Average*	
NG for electric power;														
2004 dollars	$6.28	$6.41	$6.43	$6.45	$6.47	$6.49	$6.51	$6.53	$6.55	$6.57	$6.59	$6.60	**$6.09**	Fixed $
Nominal dollars	$11.24	$11.74	$12.01	$12.29	$12.57	$12.86	$13.16	$13.46	$13.77	$14.09	$14.41	$14.74	**$9.44**	Nominal
Heat rate	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400	9400		
efficiency	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%	36.28%		
generation fuel output cost	$0.106	$0.110	$0.113	$0.115	$0.118	$0.121	$0.124	$0.127	$0.129	$0.132	$0.135	$0.139		
with capital and variable cost	$0.140	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.163	$0.166	$0.169	$0.173	**$0.123**	per kwh Nominal
Consumer price index														
GDP Chain-Type Price Index (2000=1.000)	1.953	1.998	2.038	2.079	2.120	2.163	2.206	2.250	2.295	2.341	2.388	2.435		
2004 index	1.790	1.831	1.868	1.905	1.943	1.982	2.022	2.062	2.103	2.146	2.188	2.232		

Projections to 2030 from: Annual Energy Outlook 2006 with Projections to 2030 Report #: DOE/EIA-0383(2006) Release Date: December 2005 Table 19. Macroeconomic Indicators

Table C-2. New Combustion Turbine Peaker, CCA Ownership

Natural Gas to Generate 1 KWh		
Cost/MMBtu	$6.50	
conversion to kwh	3419	btu/kwh
fuel-cost/kwh	$0.022	
heat rate	9400	btu/kwh
efficiency	36.4%	
factor	2.75	
electricity fuel-cost/kwh	**$0.061**	
Cost of Gen Facility		
Cost of Equipment	$0.48	per watt
lifecycle	20	years
capacity factor	32%	
output rate	2803	kwh/kw-yr
life output/watt	56.06	kwh
unfinanced cost	$0.008	per kwh
interest rate + ROI	5.5%	
cost of money	$0.009	per kwh
total cap cost	$0.018	per kwh
Variable costs	$0.006	per kwh
Total Gen Costs	**$0.085**	**per kwh**

Size of Plant	160,000	kw
Annual Generation	448,512,000	kwh
Lifecycle Generation	8,970,240,000	kwh
Lifecycle Costs		
Capital Cost	$76,000,000	
Cost of Money	$83,600,000	
Lifecycle Fuel Cost	$548,081,664	
Variable Cost	$51,918,348	
Total Lifecycle Cost	$759,600,012	
Savings Vs. Private Ownership	-$30,720,384	

Table C-3. New Combustion Turbine Peaker, Private Ownership

Natural Gas to Generate 1 KWh		
Cost/MMBtu	$6.50	
conversion to kwh	3419	btu/kwh
fuel-cost/kwh	$0.022	
heat rate	9400	btu/kwh
efficiency	36.4%	
factor	2.75	
electricity fuel-cost/kwh	**$0.061**	
Cost of Gen Facility		
Cost of Equipment	$0.48	per watt
lifecycle	20	years
capacity factor	32%	
output rate	2803	kwh/kw-yr
life output/watt	56.06	kwh
unfinanced cost	$0.008	per kwh
interest rate + ROI	11.8%	
cost of money	$0.020	per kwh
total cap cost	$0.028	per kwh
Variable costs	$0.006	per kwh
Total Gen Costs	**$0.095**	**per kwh**

Size of Plant	160,000	kw
Annual Generation	448,512,000	kwh
Lifecycle Generation	8,970,240,000	kwh
Lifecycle Costs		
Capital Cost	$76,000,000	
Cost of Money	$179,360,000	
Lifecycle Fuel Cost	$548,081,664	
Variable Cost	$51,918,348	
Total Lifecycle Cost	$855,360,012	

Table C-4. New Combined Cycle, Base Load, Private Ownership

Natural Gas to Generate 1 KWh		
Cost/MMBtu	$6.50	
conversion to kwh	3419	btu/kwh
fuel-cost/kwh	$0.022	
heat rate	6200	btu/kwh
efficiency	55.1%	
factor	1.81	
electricity fuel-cost/kwh	**$0.040**	74.27%
Cost of Gen Facility		
Cost of Equipment	$0.65	per watt
lifecycle	30	years
capacity factor	82%	
output rate	7183	kwh/kw-yr
life output/watt	215.50	kwh
unfinanced cost	$0.003	per kwh
interest rate + ROI	11.8%	
cost of money	$0.011	per kwh
total cap cost	$0.014	per kwh
Variable costs	$0.002	per kwh
Total Gen Costs	**$0.056**	**per kwh**

Size of Plant	500,000	kw
Annual Generation	3,591,600,000	kwh
Lifecycle Generation	107,748,000,000	kwh
Lifecycle Costs		
Capital Cost	$325,000,000	
Cost of Money	$1,150,500,000	
Lifecycle Fuel Cost	$4,342,244,400	
Variable Cost	$243,367,254	
Total Lifecycle Cost	$6,061,111,654	

Table C-5. Cost of operating a natural gas peaker plant at low, base, and high natural gas projections under private ownership.

Natural Gas to Generate 1 KWh	Low		Base		DOE/High	
Cost/MMBtu	$5.00		$6.50		$10.00	
conversion to kwh	3419	btu/kwh	3419	btu/kwh	3419	btu/kwh
fuel-cost/kwh	$0.017		$0.022		$0.034	
heat rate	9400	btu/kwh	9400	btu/kwh	9400	btu/kwh
efficiency	36.4%		36.4%		36.4%	
factor	2.75		2.75		2.75	
electricity fuel-cost/kwh	**$0.047**		**$0.061**		**$0.094**	
Cost of Gen Facility						
Cost of Equipment	$0.48	per watt	$0.48	per watt	$0.48	per watt
lifecycle	20	years	20	years	20	years
capacity factor	32%		32%		32%	
output rate	2803	kwh/kw-yr	2803	kwh/kw-yr	2803	kwh/kw-yr
life output/watt	56.06	kwh	56.06	kwh	56.06	kwh
unfinanced cost	$0.008	per kwh	$0.008	per kwh	$0.008	per kwh
interest rate + ROI	11.8%		11.8%		11.8%	
cost of money	$0.020	per kwh	$0.020	per kwh	$0.020	per kwh
total cap cost	$0.028	per kwh	$0.028	per kwh	$0.028	per kwh
Variable costs	$0.006	per kwh	$0.006	per kwh	$0.006	per kwh
Total Gen Costs	**$0.081**	**per kwh**	**$0.095**	**per kwh**	**$0.128**	**per kwh**

Table C-6. Cost of operating a natural gas peaker plant at low, base, and high natural gas projections under public ownership.

Natural Gas to Generate 1 KWh	Low		Base		DOE/High	
Cost/MMBtu	$5.00		$6.50		$10.00	
conversion to kwh	3419	btu/kwh	3419	btu/kwh	3419	btu/kwh
fuel-cost/kwh	$0.017		$0.022		$0.034	
heat rate	9400	btu/kwh	9400	btu/kwh	9400	btu/kwh
efficiency	36.4%		36.4%		36.4%	
factor	2.75		2.75		2.75	
electricity fuel-cost/kwh	**$0.047**		**$0.061**		**$0.094**	
Cost of Gen Facility						
Cost of Equipment	$0.48	per watt	$0.48	per watt	$0.48	per watt
lifecycle	20	years	20	years	20	years
capacity factor	32%		32%		32%	
output rate	2803	kwh/kw-yr	2803	kwh/kw-yr	2803	kwh/kw-yr
life output/watt	56.06	kwh	56.06	kwh	56.06	kwh
unfinanced cost	$0.008	per kwh	$0.008	per kwh	$0.008	per kwh
interest rate + ROI	5.5%		5.5%		5.5%	
cost of money	$0.009	per kwh	$0.009	per kwh	$0.009	per kwh
total cap cost	$0.018	per kwh	$0.018	per kwh	$0.018	per kwh
Variable costs	$0.006	per kwh	$0.006	per kwh	$0.006	per kwh
Total Gen Costs	**$0.071**	**per kwh**	**$0.085**	**per kwh**	**$0.118**	**per kwh**
rate savings	$0.011	per kwh	$0.011	per kwh	$0.011	per kwh

Appendix D Photovoltaics

Table D-1 examines the effect of various financial inputs into the cost per kilowatt-hour of electricity generated by solar photovoltaic system. One assumption here is that commercial entities will purchase the photovoltaic systems, and be eligible to receive tax credits and state rebates. The federal tax credit is conservatively assumed to revert to 10%, as it will naturally do after 2007 if no legislative action is taken. If the current 30% credit is extended, then the economics of photovoltaics will significantly improve for commercial/industrial sector customers that have a tax liability. The model assumes that commercial customers will borrow money for a 5 year period, paying 7.5% interest on a conventional commercial loan with a declining balance. The interest is taken on the full purchase price, not the after rebate price of the solar system. That is because we expect the new rebate program under the California Solar Initiative to pay out performance incentives over a 5 year period, so they will not affect the amount of the initial borrowing. However, upfront rebate payments under the current program design will be offered for photovoltaic systems smaller than 100 kilowatts.

The model also makes some generic assumptions about electric rates, such as a 5% local tax on sales of electricity and an initial 12 cent a kilowatt-hour rate. These only represent approximations for comparison sake. The lifecycle costs are modeled for a medium to large (10+ kilowatt) sized commercially owned photovoltaic system, and would have to be significantly modified for publicly owned or publicly financed systems, or for small home sized systems.

The analysis uses a range of cost per watt for capital expense as the basic input on the left side, running from $6.00 to $9.00 per watt of direct current electric generation capacity, a range that most photovoltaic systems would fall into. This installed capacity cost is then translated, using the various input values for performance, tax credits, loan terms and rebate, entered in the boxes in the lower part of the spreadsheet, into an effective electric rate expressed as a cost per kilowatt-hour over the life of the photovoltaic system. The lifecycle is assumed to be 30 years, which is likely to be conservative since photovoltaic modules can usually produce electricity for many more years. Most of the cost is upfront, but there is a small ongoing operation and maintenance expense, and every 10 to 20 years the inverter needs to be replaced. The larger the system, the longer the inverter is likely to last (and the lower the unit cost for replacement).

Table D-1. Photovoltaic Power Production Full Lifecycle Accounting: Commercial Ownership

PV System	PV System cost/watt	after rebate cost/watt	Interest* cost/watt	O&M	inverter	total cost	pretax cost/kwh	Tax benefit	net cost	PV net cost/kwh
cost/watt (dc)	(ac)	(ac)	(ac)		$0.60			48%		
$9.00	$10.84	$8.84	$2.19	$0.33	$0.60	**$11.97**	$0.272	$5.49	**$6.47**	$0.147
$8.50	$10.24	$8.24	$2.07	$0.33	$0.60	**$11.24**	$0.255	$5.16	**$6.09**	$0.138
$8.00	$9.64	$7.64	$1.95	$0.33	$0.60	**$10.52**	$0.239	$4.82	**$5.70**	$0.129
$7.50	$9.04	$7.04	$1.83	$0.33	$0.60	**$9.79**	$0.223	$4.48	**$5.31**	$0.121
$7.00	$8.43	$6.43	$1.71	$0.33	$0.60	**$9.07**	$0.206	$4.14	**$4.93**	$0.112
$6.50	$7.83	$5.83	$1.58	$0.33	$0.60	**$8.35**	$0.190	$3.80	**$4.54**	$0.103
$6.00	$7.23	$5.23	$1.46	$0.33	$0.60	**$7.62**	$0.173	$3.47	**$4.15**	$0.094

* assumes pbi paid out over time, full upfront cost on declining balance loan

Underlined row shows the typical cost within the last two years for commercial-scale projects in California

INPUTS		
DC output	1400	kwh/kw-yr
years	30.0	
loan term	5	years
interest rate	7.5%	
Rebate/watt**	$2.00	
tax on electric	0%	
initial electric rate	$0.120	per kwh
solar peak premium	$0.015	per kwh
cool roof	$0.000	per kwh
local tax	5%	
customer premium	$0.000	per kwh
annual escalation	2%	
REC/environmental	$0.000	per kwh

PV SYSTEM OUTPUT			
AC derate	83%	1.20	
Initial output (ac)		1687	kwh/kw-yr
Final		1248	
average		1467	
total electricity/watt		44.02	kwh

LIFECYCLE VALUE		
initial PV value rate	$0.142	
total inflation	81.1%	
final value rate	$0.257	per kwh
avg. eff. rate	$0.199	per kwh
after tax rate	$0.199	per kwh
accumulation	$8.77	per watt ac

TAX BENEFITS	rate	years	value
tax credits	10%	1	10%
Fed tax rate	33%	5	33.00%
state tax add	7%	12	7.00%
federal basis	95%		
net tax benefit			48.00%

LIFECYCLE COSTS		
inverter cost	$0.60	per watt
inv. lifecycle	20	years
replacements	1	
total inverters	$0.60	
o&m	0.0075	per kwh

Appendix E SDG&E Rates and San Diego Electric Resources

Tables E-1 and E-2 give some basic facts about electric generation in San Diego County. Table E-1 shows current rates for electric commodity charges by SDG&E, which pulls out the cost of electricity at different times of the day and year for time of use customers. These rates shown in the upper part of Table E-1 exclude distribution and service charges, as well as surcharges and taxes, which form the rest of the bill. These costs tend to reflect the average wholesale cost of generating electricity, and range from 4 to over 11 cents per kilowatt-hour.

The bottom part of the table adds the full charges back into the rate, showing an annual average cost of electricity of 15.44 cents per kilowatt-hour for customers on this rate schedule. It is noteworthy that the full cost range for photovoltaic electricity in Table D-1 falls below this rate, which makes photovoltaics an excellent hedge against future electric rate increases, *effectively freezing a commercial customer's rate below what they are presently paying*.

Table E-2 shows new power plants in San Diego County since 2001, and planned through 2008. A total of 1437 Megawatts of capacity will have been added during this period. This is likely enough to supply all the electricity needs of San Diego County's one-million-plus residential customers.*

* According to the California Energy Commission, San Diego County had 1,013,799 residential customers in 2000 that consumed a total of 6,041 million kilowatt-hours, which equates to 5959 kilowatt-hours per account per year. This represents an average load of 5959 / 8760 = 0.68 kilowatts. Therefore, 1437 Megawatts of capacity would provide 1,437,000 divided by 0.68 = 2,113,345 customers' average load, about double the actual total number of customers. Of course, the electric system capacity has to be sized for maximum, not average, load. Yet, just the *added capacity* from 2001 through 2008 should meet all the needs of the county's one million residential customers, both base and peak load.

Table E-1. SDG&E Energy and UDC Charges as of 2/1/2006

ELECTRIC ENERGY COMMODITY COST (EECC)

Schedule DR – Residential customers on separate meters

	Baseline		101%-130% of Bsln		131%-200% of Bsln		210%-300% of Bsln		above 300% of Bsln	
Effective Date	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
02/01/2006	0.06855	0.04678	0.6855	0.04678	0.06855	0.04678	0.06855	0.04678	0.06855	0.04678

Schedule AL TOU- Time of Use rate for non-residential customers whose use is greater than 20kw

Effective Date	On Peak	Semi Peak	Off Peak
02/01/2006	0.11515	0.06637	0.04537

Schedule A- Residential and commercial customers whose use does not exceed 20 kw

Effective Date	Summer	Winter
02/01/2006	0.08144	0.05617

Department of Water Resources (DWR) Bond Charge

Effective Date	
01/01/2006	0.00485

care and medical baseline excluded

ELECTRIC ENERGY COMMODITY COST (EECC) PLUS UTILITY COMPANY DISTRIBUTION (UDC) RATES

Schedule A- Residential

Effective Date	EECC Summer	UDC Summer	TOTAL Summer	EECC Winter	UDC Winter	TOTAL Winter	**Annual avg.**	Service fee per month	demand avg. kw	electricity kwh	service/kwh
02/01/2006	0.08144	0.08515	0.17144	0.05617	0.07647	0.13749	**0.154465**	$9.10	5	3600	0.002527778

Table E-2. San Diego County Power Plant Construction 2001-2009.

Project	Docket number	Status	Capacity (MW)	Construction Completed (percent)	Date Approved	Construction Start Date	Original On-line Date	Actual On-line Date
Wildflower Larkspur - Intergen	01-EP-1	Operational	90	100	04/04/2001	04/05/2001	07/01	07/16/2001
Escondido - Calpeak	01-EP-10	Operational	49.5	100	06/06/2001	06/07/2001	09/01	09/30/2001
Border - Calpeak	01-EP-14	Operational	49.5	100	07/11/2001	07/12/2001	09/01	10/26/2001
Palomar Escondido - Sempra	01-AFC-24	Operational	546	100	08/06/2003	06/01/2004	03/06	04/06
Miramar Plant		Operational	46	100				07/2005
online 1/2006	**781**	**MW**						
MMC Escondido		[redacted]	44	90%				07/2006
Biofuel Peaker			22					
Otay Mesa - Calpine	99-AFC-5	Construction	590	9	04/18/2001	9/10/01	9/10/0	01/08
by 2008	**1437**	**MW**						
Chula Vista 2 - Ramco	01-EP-3	[redacted]	62	0	06/13/2001	Cancelled	Cancelled	[redacted]

Appendix F Portfolios and Financing

Table F-1 shows the cost range of three different portfolio options, the expected annual electric generation, and the effective load carrying capacity of the facilities individually and in each of the portfolios. Some of the elements, such as photovoltaics, and perhaps wind, may not be counted by the ISO for reliability purposes. Partly for this reason, each portfolio is rated a bit higher than the stated level, but it would be possible to add to the size of the natural gas plant to make up for the difference. This would incur the least capital cost as a remedy. In addition, adjustments in the natural gas plant size may be necessary as different models come into production. If the City elects to get a mixed-use combined cycle natural gas plant, then the cost for a given size plant will likely be about 25% higher. On the other hand, the fuel efficiency may also be significantly higher.

On the other hand, adding capacity to a natural gas power plant should be a last resort, used only if other strategies do not meet the requirements. We recommend meeting the resource needs by 1) examining the full range of resource options within the county using updated demand figures, 2) evaluating construction of the appropriate Green Energy Option, and 3) challenging the ISO to account adequately for the full range of clean energy sources.

The financing assumptions are contained in Table F-2. It shows four different investor categories for power plants. These figures are used for all the plants evaluated, such as wind, pumped storage, concentrating solar thermal, and natural gas:

1) A 3rd party, private investor that borrows half the money from a bank and invests the other half out of their own resources. The expected rate of return for the portion they own is 14%; in reality this is likely to vary depending on the perceived risk. Half the money is assumed to be equity and half on borrowed funds from a bank. When the return on equity is averaged with a bank loan of 7.5%, the average cost of money is shown to be 11.8%. These figures do not account for the effect of taxes.

2) Utility owner. These have lower borrowing rates than private investors, and lower rates of return on equity in the power plant.

3) City or JPA ownership. This is a 30 year bond financed facility based upon the capital asset and long term contracts to sell power. The rate of return, 5.25 percent, is interest paid annually on the full amount of the bond, which differentiates a bond from the standard declining balance mortgage or credit card loan with which most people are familiar. Current interest rates on municipal 30 year bonds are about one percent lower. This reflects conservative assumptions, as well as embedded finance costs.

4) CCA ownership. This would be a revenue bond, limited to 20 years, with repayment based on the general ratepayer revenue stream from electric bills to the CCA. The interest rate is shown as ¼ point higher at 5.5 percent, to reflect the higher rate of return required for revenue bonds compared to bonds that are secured by a capital asset.

Table F-1. Green Energy Options-South Bay Replacement Generation Portfolios with Cost of Electricity (COE) \ for Wholesale Peak Power Generation Supply

	Capacity	Percent Load Carrying capacity	Effective Load Carrying Capacity	Capacity Factor	Annual Generation + DR	Estimated Cost		Peak COE low case		Peak COE base case		Peak COE high cas	
						Cost/ watt	Total Cost	*per kwh*	*annual*	*per kwh*	*annual*	*per kwh*	*annual*
Current Plant Value	700		700	23%	1,410,360,000	$0.15	$105,000,000						
Current Plant Replacement (potential)	620		620	80%	4,344,960,000	$0.65	$403,000,000						
Natural Gas Peaker						*See Table C-5 for calculations →*		$0.081		$0.095		$0.128	
Green Energy Portfolios													
90% Solution													
Wind Plant	400	20%	80	35%	1,226,400,000	$1.35	$540,000,000						
Pumped Storage net adjust	-183	100%		35%	-560,640,000								
Pumped Storage	150	100%	150	32%	420,480,000	$1.00	$150,000,000	$0.094	$39,525,120	$0.094	$39,525,120	$0.094	$39,525,12
Natural Gas Plant	220	100%	220	32%	616,704,000	$0.48	$105,600,000	$0.071	$43,785,984	$0.085	$52,419,840	$0.118	$72,771,07
Solar Thermal w/gas cogen	160	100%	160	32%	448,512,000	$2.50	$400,000,000	$0.091	$40,814,592	$0.091	$40,814,592	$0.092	$41,263,1C
Photovoltaic	20	60%	12	17%	29,784,000	$7.00	$140,000,000						
Demand reduction	20	100%	20	20%	35,040,000								
Total	970		642		2,216,280,000		$1,335,600,000	$0.084	$124,125,696	$0.089	$132,759,552	$0.103	$153,559,29
ELCC Target			630	32%	1,766,016,000								

	Capacity	Percent Load Carrying capacity	Effective Load Carrying Capacity	Capacity Factor	Annual Generation + DR	Estimated Cost		Peak COE low case		Peak COE base case		Peak COE high case	
						Cost/ watt	Total Cost	*per kwh*	*annual*	*per kwh*	*annual*	*per kwh*	*annual*
70% Solution													
Wind Plant	325	20%	65	35%	996,450,000	$1.35	$438,750,000						
Pumped Storage net adjust	-120	100%		35%	-336,384,000								
Pumped Storage	90	100%	90	32%	252,288,000	$1.00	$90,000,000	$0.094	$23,715,072	$0.094	$23,715,072	$0.094	$23,715,072
Natural Gas Plant	190	100%	190	32%	532,608,000	$0.48	$91,200,000	$0.071	$37,815,168	$0.085	$45,271,680	$0.118	$62,847,744
Solar Thermal w/gas cogen	160	100%	160	32%	448,512,000	$2.50	$400,000,000	$0.091	$40,814,592	$0.091	$40,814,592	$0.092	$41,263,104
Photovoltaic	20	60%	12	17%	29,784,000	$7.00	$140,000,000						
Demand reduction	20	100%	20	20%	35,040,000								
Total	805		537		1,958,298,000		$1,159,950,000	$0.083	$102,344,832	$0.089	$109,801,344	$0.104	$127,825,920
ELCC Target			490	32%	1,373,568,000								

	Capacity	Percent Load Carrying capacity	Effective Load Carrying Capacity	Capacity Factor	Annual Generation + DR	Estimated Cost		Peak COE low case		Peak COE base case		Peak COE high case	
						Cost/ watt	Total Cost	*per kwh*	*annual*	*per kwh*	*annual*	*per kwh*	*annual*
50% Solution													
Wind Plant	150	20%	30	35%	459,900,000	$1.35	$202,500,000						
Pumped Storage net adjust	-80	100%		35%	-224,256,000								
Pumped Storage	60	100%	60	32%	168,192,000	$1.00	$60,000,000	$0.094	$15,810,048	$0.094	$15,810,048	$0.094	$15,810,04
Natural Gas Plant	90	100%	90	32%	252,288,000	$0.48	$43,200,000	$0.071	$17,912,448	$0.085	$21,444,480	$0.118	$29,769,98
Solar Thermal w/gas cogen	160	100%	160	32%	448,512,000	$2.50	$400,000,000	$0.091	$40,814,592	$0.091	$40,814,592	$0.092	$41,263,10
Photovoltaic	20	60%	12	17%	29,784,000	$7.00	$140,000,000						
Demand reduction	20	100%	20	20%	35,040,000								
Total	500		352		1,169,460,000		$845,700,000	$0.086	$74,537,088	$0.09	$78,069,120	$0.10	$86,843,13
ELCC Target			350	32%	981,120,000								
Efficiency of Pumped Storage			*75%*										

Table F-2. Financing Assumptions

		Private	Utility	Public	CCA
Equity		50%	50%	0%	0%
Annual Return on Investment (ROI)		14.0%	10.5%	0.0%	0.0%
Term	years	30	30	30	20
Total ROI on Investment		2.10	1.58	0.00	0.00
Loan		50%	50%	100%	100%
Interest rate		7.50%	7.00%	5.25%	5.50%
Term	years	20	30	30	20
Total Interest		0.75	1.05	1.58	1.10
Balance of term on equity		10	0	0	0
Balance on equity		$0.70	$0.00	$0.00	$0.00
Total Cost of Capital per dollar of principal		$3.55	$2.63	$1.58	$1.10
Average Effective Rate of Capital		11.8%	8.8%	5.3%	5.5%

Appendix G Pollution Comparison Calculations

Table G-1 shows the estimated particulate matter and carbon dioxide emissions from the existing South Bay Power Plant, the proposed South Bay Replacement Project, and the three Green Energy Option portfolios. Of the criteria pollutants, we chose to estimate emissions of particulate matter (PM), as this is the primary air pollution concern from the existing and proposed plants. Emissions of PM from power plants are significant, and PM levels in Chula Vista exceed state and national air quality standards. We also estimated carbon dioxide emissions to illustrate the differences in greenhouse gas emissions among the energy portfolio options.

Table G-1. South Bay Power Plant Replacement Options, Comparison of Air Pollution and Greenhouse Gas

					Natural Gas Use		Emissions		Emissions	
Scenario	Capacity	Capacity Factor	Annual Generation	Heat Rate			PM10/2.5	CO2	PM10/2.5	CO2
	MW		GWh/year	btu/ kwh	MMBtu/ year	MMscf/ year	Tons/ year	Tons/ year	lbs/ MWh	lbs/ MWh
Existing South Bay Power Plant	**700**	**32%** [1]	**1,962**	**10,068**	**19,755,832**	**19,180**	**72.9**	**1,155,716**	**0.074**	**1178**
Proposed South Bay Replacement Plant	running as a base-load plant w/ intermittent duct firing									
Base load	500 [2]	80%	3,504	6993 [3]	24,503,472	23,790	90.4	1,433,453	0.052	818
With duct firing	120	9% [4]	96	9488	910,848	884	3.4	53,285	0.070	1110
Total for SBRP	**620**	**66%**	**3,600**		**25,414,320**	**24,674**	**93.8**	**1,486,738**	**0.052**	**826**
New Natural Gas Peaking Plant	**700**	**32%**	**1,962**	**9400**	**18,445,056**	**17,908**	**68.0**	**1,079,036**	**0.069**	**1100**

[1] For comparison with the Green Energy Portfolios, the capacity factor is consistent with that of the GEOs. LS Power's AFC on the South Bay Replacement Project states that the SBPP's capacity factor is currently at about 30%.
[2] SBRP AFC before CEC page 2-38
[3] Table 2.3-6 in SBRP AFC before the CEC
[4] Assumes 800 hours duct firing per year per CEC data request.

Scenario	Capacity	Capacity Factor	Annual Generation	Heat Rate	Natural Gas Use		Emissions		Emissions	
							PM10/2.5	CO2	PM10/2.5	CO2
	MW		GWh/year	btu/ kwh	MMBtu/ year	MMscf/ year	Tons/ year	Tons/ year	lbs/ MWh	lbs/ MWh
Green Energy Portfolios										
90% Solution	**630 MW ELC Capacity**									
Wind Plant	400	35%	1,226							
Pumped Storage net adjust	-183	35%	-561							
Pumped Storage	150	32%	420							
Natural Gas Plant	220	32%	533	9400	5,797,158	5,628	21.4	339,126	0.069	1100
Solar Thermal	160	21%	294							
Natural Gas from Solar Thermal	160	11%	154	9400	1,449,254	1,407	5.3	84,781	0.359	5693
Photovoltaic	20	17%	30							
Demand reduction	20	20%	175							
			2,216		**7,246,242**	**7,035**	**26.7**	**423,907**	**0.024**	**383**
70% Solution	**490 MW ELC Capacity**									
Wind Plant	325	35%	996							
Pumped Storage net adjust	-110	35%	-336							
Pumped Storage	90	32%	252							
Natural Gas Plant 1	190	32%	533	9400	5,006,515	4,861	18.5	292,881	0.069	1100
Solar Thermal	160	21%	294							
Natural Gas from Solar Thermal	160	11%	154	9400	1,449,254	1,407	5.3	84,781	0.069	1100
Photovoltaic	20	17%	30							
Demand reduction	20	20%	175							
Total	**945**		**1,958**		**6,455,770**	**6,268**	**23.8**	**377,663**	**0.024**	**386**

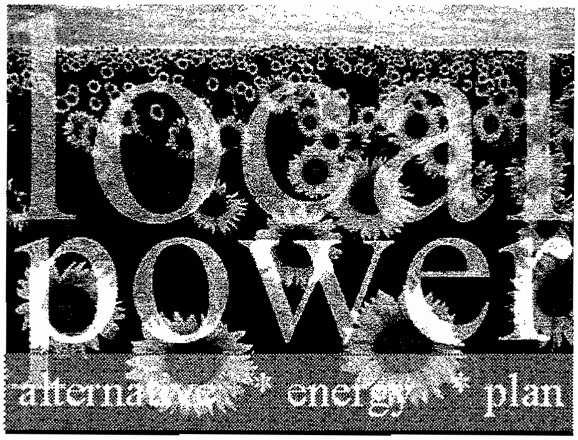
Scenario	Capacity	Capacity Factor	Annual Generation	Heat Rate	Natural Gas Use		Emissions		Emissions	
							PM10/2.5	CO2	PM10/2.5	CO2
	MW		GWh/year	btu/ kwh	MMBtu/ year	MMscf/ year	Tons/ year	Tons/ year	lbs/ MWh	lbs/ MWh
50% Solution	**350 MW ELC Capacity**									
Wind Plant	150	35%	460							
Pumped Storage net adjust	-73	35%	-224							
Pumped Storage	60	32%	168							
Natural Gas Plant	90	32%	252	9400	2,371,507	2,302	8.7	138,733	0.069	1100
Solar Thermal	160	21%	294							
Natural Gas from Solar Thermal	160	17%	238	9400	1,449,254	1,407	5.3	131,026	0.069	1100
Photovoltaic	20	17%	30							
Demand reduction	20	20%	175.2							
			1,169		**3,820,761**	**4,477**	**14.1**	**223,515**	**0.024**	**382**

Notes:

Efficiency of Pumped Storage	75%		
Btus natural gas/cubic foot	1030		
Emission Factors:			
Particulate Matter	7.6	lbs/scf	EPA AP 42 emission factor for total PM
CO2 emission factor	117	pounds per MMBtu of NG burned	US EPA. Personal Emissions Calculator References. www.epa.gov/climatechange/emissions/ind_assumptions.html

Environmental HEALTH COALITION

Green Energy Options for the Future

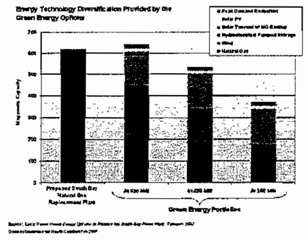


New Report Now Released

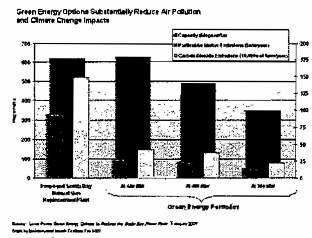
The "Green Energy Options" (GEO) outlined in this report, demonstrate how Chula Vista and neighboring communities can now move to develop solar, wind and other green power technologies at market prices, stabilize local electricity rates, win energy independence, and eliminate a major contributor of pollution and greenhouse gases. The City of Chula Vista has already taken a leadership role in promoting energy sustainability and taking responsibility for reducing the hazards associated with the global climate crisis. By investing in energy development described in this Green Energy Options report, the City of Chula Vista can take a major step toward ensuring energy and economic security for Chula Vista and the region, and can set an example for the region, state, and beyond.

GEO REPORT	**Full PDF - 700 KB**
GEO APPENDICES	**Full PDF - 150 KB**

EHC Media Release



Energy Technology Diversification Provided by the Green Energy Options



Green Energy Options Substantially Reduce Air Pollution and Climate Change Impacts

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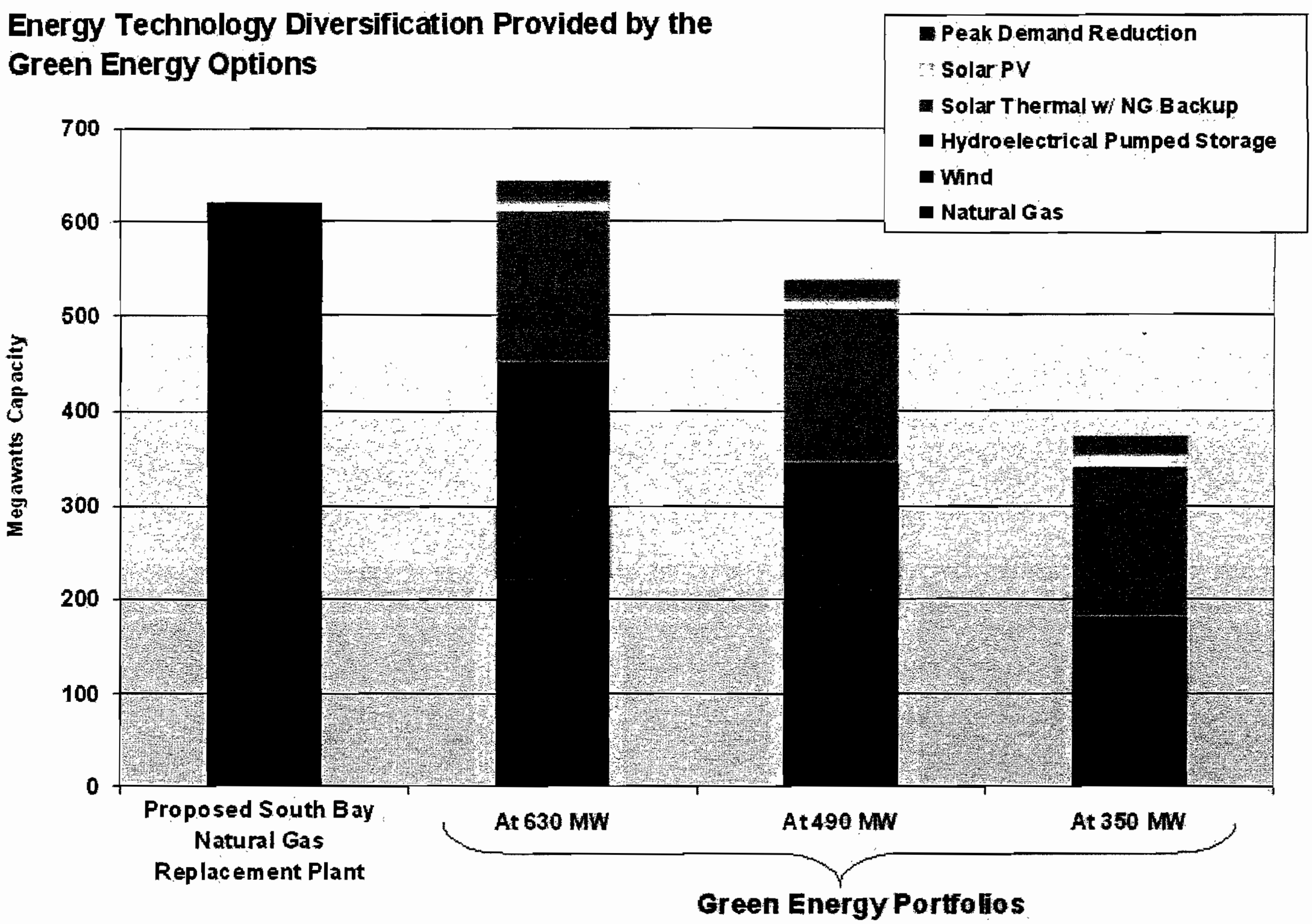
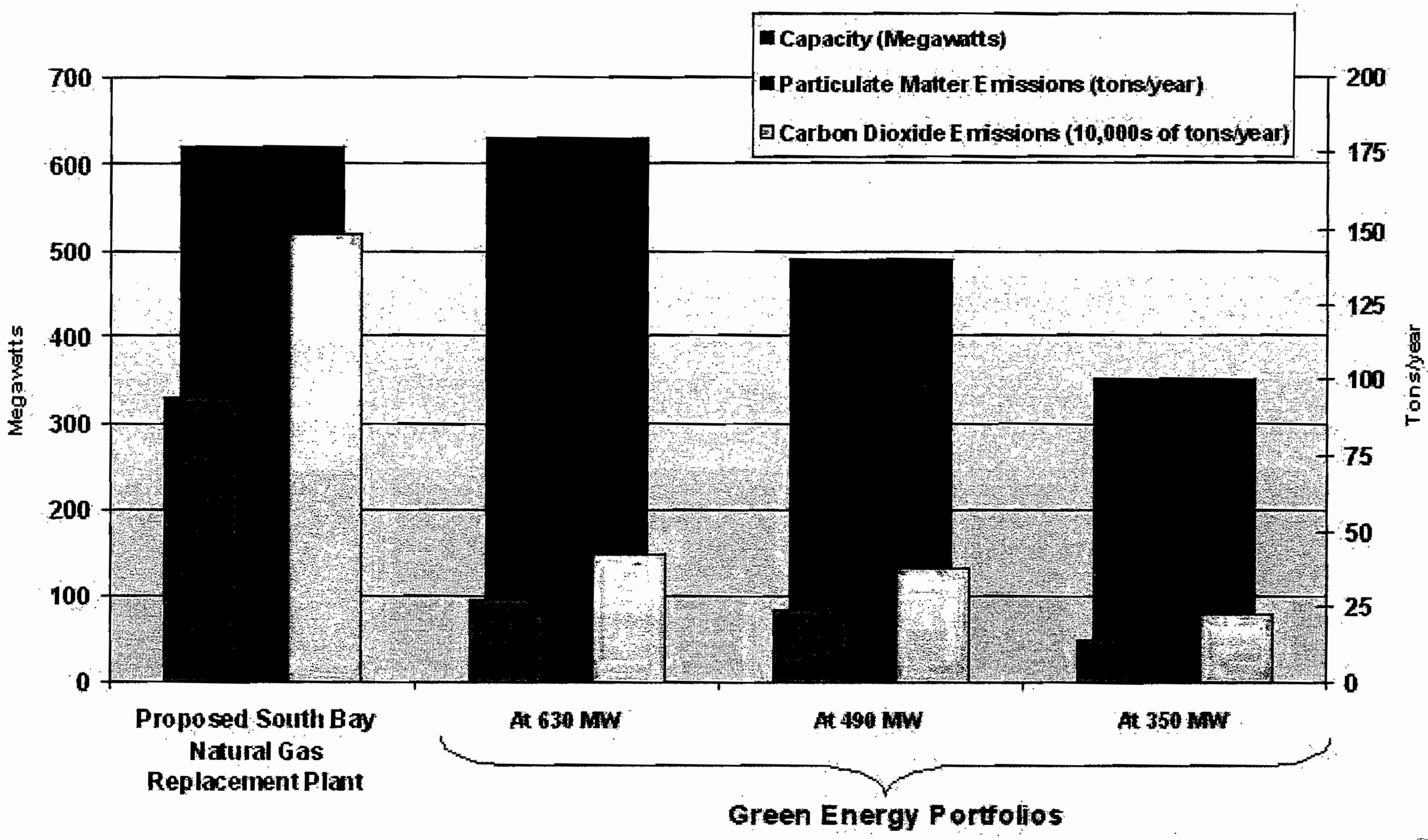


Source: Local Power *Green Energy Options to Replace the South Bay Power Plant* February 2007.

Graph by Environmental Health Coalition Feb 2007

Green Energy Options Substantially Reduce Air Pollution and Climate Change Impacts



Source: Local Power *Green Energy Options to Replace the South Bay Power Plant* February 2007.
Graph by Environmental Health Coalition Feb 2007

Environmental HEALTH COALITION

Media Release

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For Immediate Release

Green Energy Options Report Released to Address San Diego Energy Future

(February 15, 2007) – San Diego, California. Environmental Health Coalition (EHC) released *Green Energy Options for Replacing the South Bay Power Plant* (GEO) today, a report by Oakland-based non-profit Local Power, Inc., which makes it clear that **clean, secure energy solutions are available** to meet our energy needs now and into the future.

EHC called on the City of Chula Vista and the San Diego Port District to take action now to secure the tear-down of the current South Bay Power Plant when the lease expires in February, 2010, and to join with other leaders to develop a **South Bay Clean Energy Action Plan**.

The GEO reports on the feasibility and cost-effectiveness of replacing the South Bay Power Plant with competitive clean energy solutions by 2010. The report demonstrates the economic and environmental benefits of meeting the region's future energy needs with *diverse* and *decentralized* energy resources and offers a plan that reduces dependency on imported energy supplies.

Instead of continuing reliance on a large natural gas-fired plant, the GEO outlines choices that would constitute a diversified portfolio that includes:

- aggressive energy efficiency and demand reduction,
- solar and other renewable generation sources,
- improvement in the efficiency of the existing transmission grid, and
- strategically located and greatly scaled down natural gas-fired generation with the option to recycle waste heat for commercial and industrial use

"The report documents that there are clean energy options for meeting our energy needs without the large, polluting, gas-fired power plant proposed by LS Power. These options would not only be cost-effective, but would set us on the path to reduce greenhouse gases. Our goal is to make sure that these choices are considered now," stated Diane Takvorian, Executive Director of Environmental Health Coalition.

In supporting the direction outlined in the GEO report and the initiation of a clean energy action plan, Chula Vista City Councilmember Steve Castañeda stated, "It is critical that South Bay leadership forge a unified direction on meeting our future energy needs. I'll be urging my colleagues on the City Council to take necessary action soon to ensure that power generation is moved off our bayfront and we focus on cleaner energy choices for the future. We know it will be better for our health and our economy in the long-run."

While the GEO report outlines three conceptual energy portfolios for cleaner options that would allow the reliability-must-run status to be removed from the current power plant, it also outlines the many benefits of renewable energy development.

Key Findings of the GEO Report

Greener energy options exist within San Diego County and, coupled with maximizing the efficiency of existing transmission lines, building standards, demand response, and decentralized renewable energy development, the need for another large, gas-fired baseload power plant on the Bayfront should be avoided.

Chula Vista is best poised to pursue a greener energy portfolio through the application of Community Choice Aggregation or other municipal funding mechanisms.

Greener energy options could reduce particulate pollution and carbon dioxide emissions every year by 60-80% over a new gas-fired plant.

Chula Vista investment in renewable energy and conservation facilities involves a lower degree of economic risk than investment in a 100% natural gas generation power plant, because there is reduced exposure to the highly volatile price of natural gas that usually constitutes from 50% to 80% of the life cycle cost of a gas-fired power plant.

Renewable and conservation facility assets will retain their market value and generate revenue after bonds or other financing are repaid, in some cases for decades, offering both returns on public investment and very low cost energy for local government, residents and businesses.

Potential green energy assets exist in the region to avoid the need for another large transmission line like the Sunrise Powerlink or a replacement power plant on the Bayfront.

The Greener Energy Options will help the region to meet the state-mandated renewable energy targets with local resources. SDGE only has 6% renewables of the required 20% that they will need by 2010.

In addition to the proposed green portfolios, the GEO report identifies 1695 megawatts of alternative ways to meet San Diego regional grid reliability needs.

With the release of this report, EHC is calling on the City of Chula Vista and the Port of San Diego to end speculation about future power plant development on the Bayfront and withdraw the option of a lease for a new large power plant on the bayfront.

Allen Shur, Business Agent for IBEW's Local 569, pointed to the job-related benefits of greener energy choices. "Diversifying our energy sources now means that we have the opportunity to create new jobs by working to bring renewable energy manufacturing jobs to the region, by promoting the construction of high-performance and energy-efficient buildings, by improving the performance of our existing energy system, and by building and improving public infrastructure," stated Shur.

The South Bay area is currently host to the existing SBPP, the future Otay Mesa Generating Station (a 561 Megawatt Baseload plant scheduled to go on-line in 2009), three peaker power plants, and several large transmission projects including the Southwest Powerlink, and the Otay Metro Loop. The South Bay region needs a South Bay Clean Energy Action Plan to achieve clean, cost-effective, and secure energy for the future.

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