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BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

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APPLICATION FOR CERTIFICATION	**Docket No. 11-AFC-01**

Rob Simpson's and Helping Hand Tools Supplement Comments to the PMPD
Part 1b of 5

The following 11 emails and attachments were submitted to all parties on or about September 5, 2012. Mr. Simpson and Helping Hand Tools submits this document for public comment.

Respectfully submitted.

Date: September 11, 2012 /s/ Gretel Smith , Esq.

Gretel Smith, Esq.

Attorney for Helping Hand Tools &

Rob Simpson

9. Demand Response: Current Utility Program, Pricing and Smart Meters[120]

9.1 Why California is falling short on reducing peak demand

California will fall short of achieving its goal of reducing system peak demand for the three IOUs by 5 percent in the summer of 2007. This goal specifically applies to price response programs that can be called on a day in advance and are designed to address forecasted peaks or supply constraints. Price response programs are likely to reduce peak demand by 2.2 percent, or less than half of the target percentage.

To identify why the state's demand response goals will not be achieved this year, the Brattle Group, which provides consulting services and expert testimony in economics, finance and regulation, interviewed two dozen stakeholders within and outside of California. Several reasons for not meeting the demand response goals emerged.

First, the goals focused solely on price response programs, which require advanced interval meters. When the goals were set, only customers with greater than 200 kW demand, representing about one-fourth of the system peak load, had these meters. Achieving the 5 percent goal from large customers alone requires that they reduce their peak demand by about 20 percent.

Second, even by 2011, when advanced metering infrastructure will be installed for customers under 200 kW, a large portion of the electricity consumption in the commercial customer class with demand under 200 kW will continue to be protected from rate changes by AB 1X. This protection may last through the year 2021.

Large customers already face time-of-use (TOU) rates that charge higher prices for demand during peak periods. Many of the largest customers have been on TOU for years. Over 23,000 advanced interval meters were installed for customers with greater than 200 kW of demand as a result of AB 29X. The legislation required that all meter recipients shift to TOU rates. Much of the potential for peak load reduction from the largest commercial customers has already been realized as they have adapted their operations to higher peak prices.

The utilities have proposed voluntary critical peak pricing rates and peak time rebates to accommodate the AB 1X provisions. However, the true potential for demand response from commercial customers is unlikely to be achieved due to a combination of complications. For example, there is currently a built-in disincentive to customers with average demand under 200 kW and with a high peak demand to leave a program, AB 1X, that protects these customers from rate spikes.

The current approach appears to be too centered on the utility and may need to be replaced with an approach focused on customer needs and infrastructure constraints. California lags behind states with restructured power markets where all large customers above 1 MW face default hourly real-time pricing tariffs. Most regions with active demand response programs have both “day ahead” and “day of” programs using a combination of pricing and rebate payments to encourage customers to lower peak loads and/or shift load to off-peak periods.

9.2 Steps necessary to get more from demand response

Rate and program designs must be developed that better reflect the value of demand response to the electricity system and the value of consumption to customers. California has pursued its energy efficiency goals through a combination of programs and standards. At least half of the efficiency gains that have been realized since 1975 have been due to standards. Now may be the time to examine the potential for using standards to achieve the state's demand response goals.

Cost-benefit methodologies for evaluating demand-side programs need to be improved. Protocols must be developed for measuring demand response impacts. Innovative rate designs are needed that incorporate the risks of outages and high peak generation costs.

Dynamic rate designs and effective protocols for measuring demand response impacts are steps toward solving these problems. There is a need to better educate customers about the costs embodied in current rates, the benefits that could come from broad adoption of dynamic rates, the true impacts on their electricity costs that would result from such a change, and the options they have for responding.

Many customers assume such rates would amount to rate increases when in fact utility revenue would not change. Customers whose consumption patterns reflect below average peak consumption would see bill reductions. Those with above average peak consumption would see increases that reflect the degree to which their peak consumption is currently receiving a hidden subsidy from other customers.

9.3 Smart meters are a part of the solution

The demand for electricity is highly concentrated in the top 1 percent of hours of the year. In most parts of the United States, these 80 to 100 hours account for roughly 8 to 12 percent of the maximum or peak demand. In California, they account for approximately 11 percent.

If a way can be found to reduce some of this peak demand, it would eliminate the need to install generation capacity that would be used less than 100 hours a year. This generating capacity is primarily gas-fired peaking combustion turbines. This is expensive power generation given these turbines are idle for almost all of the year.

How much will be saved by demand response will depend on two issues: 1) how much peak load can be reduced by customers and 2) how much generation (and related power delivery) investment and fuel can be offset by this load reduction. The first item depends on two things: how rapidly utilities and regulators move to install new pricing designs that provide the correct price signals to customers, and how well customers respond to the price signals.

A prerequisite to the provision of dynamic pricing is the installation of Advanced Metering Infrastructure (AMI). Depending on features and geography, AMI investment costs can range from $100 to $200 per meter. Much of that cost can be recovered through operational benefits such as avoided meter reading costs, faster outage detection, improved customer service, better management of customer connects and disconnects, and improved distribution management.

Many utilities have already installed AMI because they were able to recover their entire investment through operational benefits. According to a recent Federal Energy Regulatory Commission report, AMI currently reaches 6 percent of electric meters in the United States. Certain states, such as Pennsylvania and Wisconsin, have AMI penetration rates in excess of 40 percent. AMI penetration rates are in the double digits in eight states.[121]

California's three IOUs tested a variety of dynamic pricing designs in a $20 million pilot project that involved approximately 2,500 residential and small commercial and industrial customers over a three-year period. The experimental process involved a working group that was facilitated by the CPUC and CEC and many interested parties, some opposed to dynamic pricing and some supporting it.

The California experiment provided time-varying prices and smart meters to all participants. In addition, some of the participants also received enabling technologies such as smart thermostats and always-on gateway systems. Smart thermostats automatically raise the temperature setting on the thermostat by 2 or 4 degrees when the price becomes critical. Always-on gateway systems adjust the usage of multiple appliances in a similar fashion and represent the state-of-the art.

The experiment showed that the average Californian customer reduced demand during the top 60 summer hours by 13 percent in response to dynamic pricing signals that were 5 times higher than their standard tariff. Customers who had a smart thermostat reduced their load about twice as much, by 27 percent. And those who had the gateway system reduced their load by 43 percent. The AMI meters that SDG&E will install will be capable of supporting smart thermostat controls and gateway systems.

The gateway "smart meter" system represents the maximum technical potential for demand reduction in the residential customer class. The smart meter system has the potential for lowering peak demand by 43 percent. In the commercial and industrial classes, automatic demand response programs that control multiple end-use loads while working with the energy management system that is installed in most facilities are projected to reduce demand by 13 percent. The weighted average technical demand response potential for all classes is estimated at approximately 23 percent.

The peak demand in SDG&E service territory in 2007 was 4,636 MW. A 23 percent reduction in 2007 peak demand through use of smart meters represents a demand reduction of approximately 1,070 MW. SDG&E estimates that the use of smart meters in SDG&E territory will result in a 5 percent reduction of peak demand 2016, a forecast demand reduction of 249 MW.[122]

10. San Diego Solar Initiative: Cost-Effective Regional Photovoltaics

10.1 Design of California Solar Initiative

The SB1 "million solar roofs" legislation has established the objective of adding 3,000 MW of commercial and residential PV installations in California by 2017. SDG&E serves approximately 10 percent of the IOU customer base in California, and for that reason it is assumed that 300 MW of this PV capacity will be added in SDG&E service territory.[123] $3.35 billion in incentives will be paid-out over the course of the 10-year program. The objective of these incentive payments, in combination with federal and state tax incentives, is to make PV cost-competitive with purchased utility power.

The 12 kW system example shown in Table 10-1 demonstrates the financial impact of the incentive payment and tax credits on the net cost of the PV system. The 12 kW system used in the example is presumed to be a system installed on a residence under a commercial third party power purchase agreement structure.

Table 10-1. Net Cost of 12 kW PV System under SB1 California Solar Initiative[124]

Cost or (Credit), $	Cost Element
100,000	gross cost of 12 kW PV system @ approximately $8 per installed watt
(15,000)	net CSI incentive payment, gross incentive of $25,000 less income tax paid of $10,000
(30,000)	30 percent federal tax credit on gross cost
(28,000)	depreciation on gross cost less tax credit ($70,000 × tax rate)
27,000	net cost of PV system

The annual loan payment would be $2,500 per year, assuming the net capital cost of $27,000 is amortized at 7 percent interest over 20 years. This system would be expected to generate approximately 1,550 kWh per year kW installed, or 1,550 kW × 12 kW = 18,600 kWh per year. Dividing the annual cost of $2,500 by the annual power production of 18,600 kWh gives a unit electricity generation cost of $0.135/kWh. This compares to a typical current SDG&E electric energy charge of $0.15 to $0.25/kWh for residential customers.[125]

Commercial PV systems rely on the incentives, tax credits, and depreciation shown in Table 10-1 to produce electricity that is competitive with utility electricity rates. The major program under SB1 is the California Solar Initiative (CSI). CSI has a $2.165 billion incentives budget and a goal of 1,940 MW of new PV capacity by 2017. The CSI program provides performance-based incentive payments for each kWh produced from commercial PV systems instead of a flat initial payment for smaller systems that is based on the size of the PV system.

The fundamental concept behind the CSI program is that a large increase in demand for PV systems will steadily reduce the cost of PV to the point where PV technology will be cost-competitive with purchased utility electricity rates by 2017 without incentive payments (though assuming federal and state tax credits remain). Expectations of large growth in PV capacity are predicated on the cost of PV steadily dropping over the next decade to half the current cost due in part to the large demand increase created by the CSI incentives.

Favorable utility tariffs will play an important role in driving the expanded use of PV in commercial systems as well. Most of the initial CSI incentives for commercial PV systems went to applicants in PG&E service territory, in part because of a favorable rate structure for PV systems. This rate structure, known as the A-6 tariff, pays nearly triple the proposed SDG&E rate for commercial solar power.[126] The PG&E and SDG&E rate structures for commercial solar installations are compared in Table 10-2. A SDG&E commercial solar tariff structure that is comparable to the PG&E tariff would allow commercial PV in SDG&E service territory to compete on a level playing field for statewide incentive payments under CSI.

Table 10-2. Comparison of PG&E and SDG&E Commercial PV Rate Structures

	PG&E A-6 tariff	SDG&E AL-TOU tariff (proposed)[127]
Energy Charges ($/kWh)		
Summer		
Peak	0.319	0.109
Part-peak	0.157	0.092
Off-peak	0.093	0.073
Winter		
Peak		0.108
Part-peak	0.138	0.100
Off-peak	0.102	0.079
Demand Charges ($/kW)		
Facility charges	none	10.70
Summer peak	none	4.72
Winter	none	3.59

10.2 Proposed San Diego Solar Initiative

10.2.1 Achieving 50 Percent Greenhouse Gas Reduction with Photovoltaics

A primary goal of *San Diego Smart Energy 2020* is to reduce greenhouse gas emissions from power generation serving San Diego County customers as rapidly as cost-effectively feasible. Accelerated use energy efficiency measures and renewable energy will be necessary to achieve this goal. The *Regional Energy Strategy 2030* establishes a goal of 50 percent of the renewable energy used in the region coming from local renewable energy resources. The large majority of the renewable resources that SDG&E is proposing to utilize to meet the SB 107 “20 percent by 2010” renewable energy mandate, primarily biomass, wind, geothermal, and solar power, will be imported from other regions.

The most abundant renewable resource in San Diego County is the sun. San Diego County currently has approximately 38 MW of installed commercial and residential PV capacity. San Diego County also has thousands of MW of PV potential on existing commercial buildings, parking lots and parking structures, and residences. Rooftop PV has the advantage of being relatively non-controversial from a siting standpoint. The City of San Diego and San Diego Schools pay less per kWh for PV power purchased from third party providers than the energy charge they would otherwise pay SDG&E for the same power generated by conventional power plants. This is possible under the current matrix of PV incentives, tax credits, and depreciation that apply to these PV systems.

For these reasons, the renewable energy component of *San Diego Smart Energy 2020* is focused on local rooftop PV, primarily commercial installations, to expand the renewable energy component of the power used by San Diego County businesses and residences from 20 percent in 2010 to 50 percent in 2020. PV is arguably the best renewable energy "fit" for San Diego County, due primarily to the fact that PV is generated at the point of use and is generally operating at or near capacity when electric power is most needed and most valuable. This is especially true if the PV systems are equipped with adequate battery storage to operate as reliable peaking power units during summertime afternoon peak demand periods.

The renewable energy component of *San Diego Smart Energy 2020* would require the addition of just over 2,000 MW of PV by 2020 to achieve a 50 percent GHG reduction from electric power generation. A leading developer of commercial solar PV was contacted by Powers Engineering to provide an estimate of the incentives budget necessary to cost-effectively meet this PV target by 2020. "Cost-effective" in this case means a payback in approximately 10 years for a commercial PV system in a market where the benchmark utility electric rate is $0.12/kWh.The estimated life-of-project PV incentives budget to achieve this goal is estimated at $1.5 billion (in 2007 dollars).[128] All of this $1.5 billion incentive budget would be utilized to build renewable PV distributed generation in the San Diego region. The *San Diego Solar Initiative* is an appropriate name for this PV program.

The *San Diego Solar Initiative* would be far less expensive than the proposed SPL transmission project over time. The capital cost estimated by SDG&E for its portion of the transmission project is $1.265 billion. The estimated total cost over the 40-year project lifetime, including SDG&E profit, is approximately $7 billion in 2010 dollars.[129] A recent proposal by SDG&E to underground the transmission line between Lake Henshaw and Santa Ysabel could add up to another $300 million to the capital cost, increasing the estimate to $1.565 billion.[130] This would in turn increase the levelized cost of the project over 40 years from $7 billion to $8.3 billion.

The cost to build transmission lines is also rising rapidly in general. A recent report prepared by the Brattle Group for the Edison Foundation states that price increases in the past several years have affected all utility sector investments from coal and wind power projects to transmission and distribution projects. Between January 2004 and January 2007, the costs of steam-generation plants, transmission projects, and distribution equipment rose by 25 to 35 percent (compared with an 8 percent rise in the overall price level). The coauthor of the report noted that if these cost increases persist, they will confront utilities and regulators with even tougher choices on capital investment plans in the future, and motivate stepped-up conservation and demand-side programs.[131]

The levelized annual cost of the proposed SPL transmission project, in 2006 dollars, is $174 million per year for 40 years. This expenditure would provide 1,000 MW of additional import capacity to the San Diego region. However, there is no assurance that there will be power to import over the line during periods of peak regional demand. For example, the California Independent System Operator (CAISO) declared a statewide Stage 1 electrical emergency on August 29, 2007 from 3:20 pm to 8:00 pm. A Stage 1 emergency designation is a call for voluntary conservation. The Stage 1 press release issued by CAISO stated a primary reason for the Stage 1 emergency was, "*temperatures throughout the Southwest continue to climb, decreasing the availability of imported power*."[132] The existence of transmission capacity does not assure that the transmission capacity can be utilized during periods of peak demand if electricity demand is peaking throughout the region at the same time.

The $1.5 billion incentives budget under the *San Diego Solar Initiative* would total $1.5 billion over 20 years in current dollars. The average annual cost of the *San Diego Solar Initiative*, in 2007 dollars, would be $76 million per year over the 20-year life of the incentive payment program, less than one-half the cost of the SPL over the same time period. The distribution of the $1.5 billion in PV incentives is shown in the PV incentive program financing plan summary tables included in **Attachment J**.

The $1.5 billion budget would incentivize the installation of 2,040 MW of commercial PV (primarily) in the San Diego region by 2020. This PV capacity will be equipped with sufficient battery storage so that it can reliably serve the afternoon peak load at rated output. This capacity is in addition to the 300 MW of PV that will be installed in SDG&E service territory by 2017 as a result of SB1.

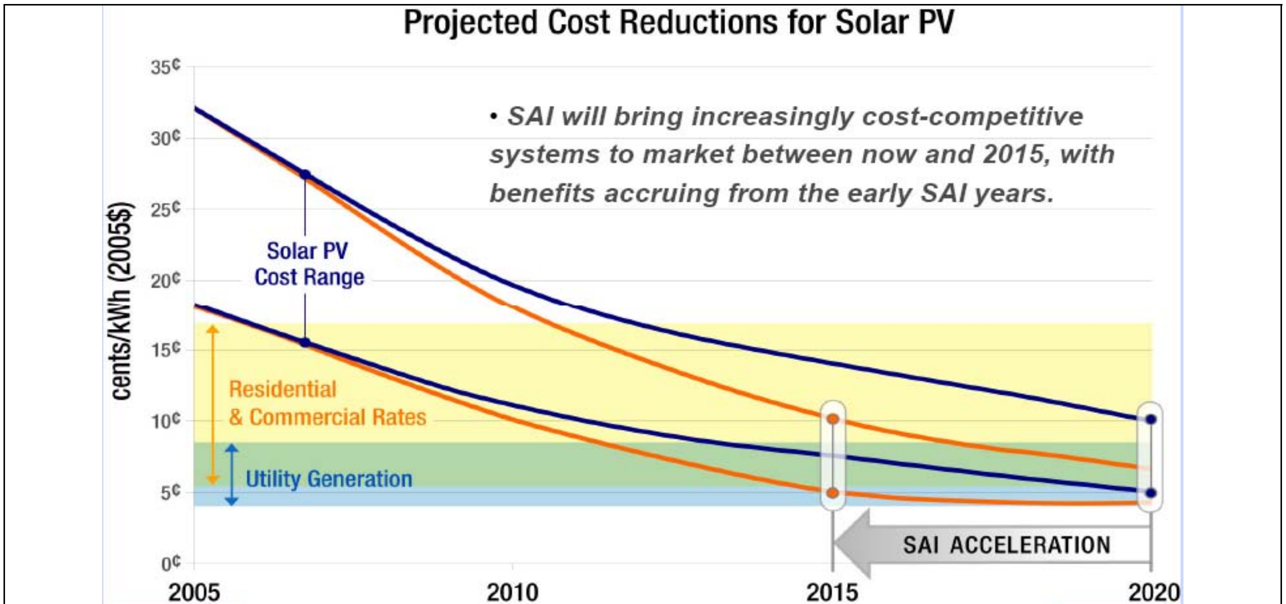
The assumptions behind this addition of 2,040 MW by 2020 are that current federal tax credits and accelerated depreciation remain in place, and customers pay a third party provider $0.12/kWh for the PV energy. Additional assumptions are that the majority of the installed capacity, approximately 75 percent, will be commercial installations over 100 kW, and that a high level of standardization will be utilized by a limited number of large contractors to minimize costs through bulk purchasing of PV system hardware.

Achieving the goal of 2,040 MW installed by 2020 under the *San Diego Solar Initiative* is also based on the installed cost of PV systems dropping by approximately 40 percent between 2008 and 2017. The *San Diego Solar Initiative* would be a major PV incentive program in addition to SB1, accelerating the decline in PV cost relative to conventional power generation. The current installed cost of residential rooftop PV systems is approximately $8 per watt prior to incentive payments and tax credits (see Table 10-1). The cost is 10 to 15 percent lower for large wholesale buyers of PV panels and associated hardware.[133]

This projected decline in the cost of PV systems is conservative relative to U.S. Department of Energy (DOE) projections and current industry trends. Figure 10-1 is a DOE projection of the decline in PV costs through 2020. DOE estimates PV will reach cost parity with high cost conventional baseload power generation by 2020 under a "business as usual" scenario. The

CPUC now limits utility baseload long-term power contracts to sources with a GHG footprint of a natural gas-fired combined cycle power plant. This is high-cost baseload power generation in a time when natural gas averages $7 per million Btu or more. According to DOE, cost parity will be reached by 2015 if PV is incentivized to ensure a large and growing market over the next decade. See the lower curve in Figure 10-1.

Figure 10-1. DOE Projection of Decline in PV Cost Through 2020[134]



Market Sector	Current U.S. Market Price Range (¢/kWh)	Cost (¢/kWh) Benchmark 2005	Cost (¢/kWh) Target 2010	Cost (¢/kWh) Target 2015
Residential	5.8-16.7	23-32	13-18	8-10
Commercial	5.4-15.0	16-22	9-12	6-8
Utility	4.0-7.6	13-22	10-15	5-7

There are currently limits on the availability of PV panels. However, a very rapid expansion of PV manufacturing capacity is underway. Worldwide PV manufacturing capacity expanded 41 percent in 2006. Production is currently constrained by a shortage of manufacturing capacity. However, more than a dozen companies in Europe, China, Japan, and the U.S. will bring unprecedented levels of production capacity online in the next two years, reversing manufacturing constraints. The PV industry estimates the cost of PV will decline 40 percent by 2010 as a result of this tremendous expansion in PV production capacity.[135]

The 2,040 MW of PV to be added under the *San Diego Solar Initiative* would be equipped with sufficient battery storage, equivalent to 2 to 3 hours of rated capacity, to enable this PV capacity to be dispatchable during the late afternoon peak. 2,040 MW of PV capacity would meet more than half of San Diego County's projected peak demand (under *San Diego Smart Energy 2020*) of 3,500 MW in 2020.

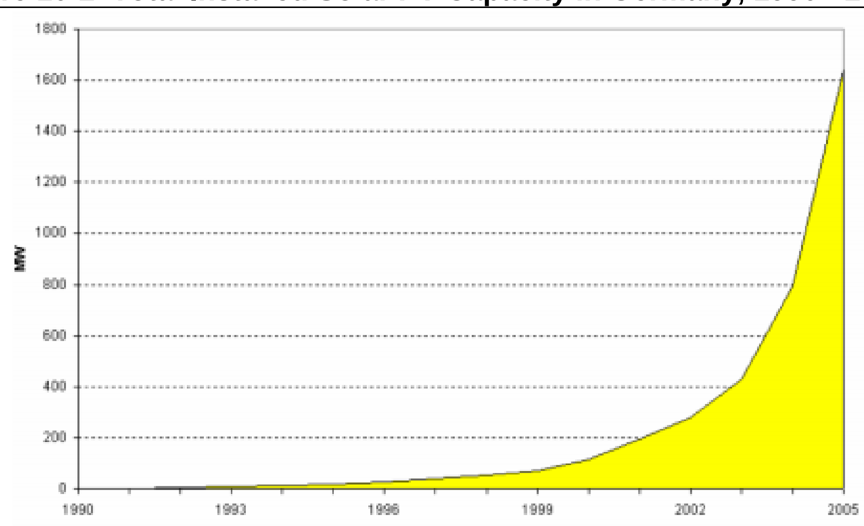
PV systems provide peak power output in the middle of the day, yet peak demand is generally later in the afternoon, typically 3 pm to 6 pm. The CEC is funding a demonstration in Southern California Edison territory of sophisticated energy management/battery systems integrated with residential PV to serve as peaking units to meet the late afternoon summertime peak.[136] The energy management/battery systems are fully controllable by the utility as peaking units. The addition of energy management and battery storage allows the PV system to supply the utility grid with its rated output through the late afternoon summertime demand peak. The energy management/battery system adds approximately 10 percent to the cost of the PV system.[137]

The San Diego region is projected to have approximately 4,600 MW of PV technical potential on commercial buildings, parking structures, and parking lots in 2010, as well as 2,800 MW of technical potential on residential structures.[138] The 2,040 MW PV target will be developed from this 7,400 MW of PV technical resource base.

The annual energy production of this PV capacity developed under the *San Diego Solar Initiative* will be approximately 25 percent of the region's annual energy demand in 2020. SDG&E is obligated by SB 107 to obtain 20 percent of its power sales from renewable energy sources by 2010. An assumption in *San Diego Smart Energy 2020* is that the energy generated by these renewable energy contracts, 3,500 GWh per year, continues to be produced at the 3,500 GWh per year level for the foreseeable future. 3,500 GWh per year will be approximately 22 percent of total energy demand in 2020. The 300 MW of regional PV added under SB1 will supply 3 percent of total energy demand. Combined, these renewable energy sources will provide 50 percent of the region's annual energy demand in 2020.

The *San Diego Solar Initiative* would follow a development curve, in terms of rate of growth in installed PV power, similar to the rate-of-growth demonstrated in the German PV program. The German PV program reached a growth rate of 837 MW per year in 2005. See Figure 10-2. The *San Diego Solar Initiative* would start gradually and finish fast. Approximately 40 MW would be installed in 2008-2010, the first three years of the *Initiative*. 2,040 MW would be in operation by 2020.

Figure 10-2. Total Installed Solar PV Capacity in Germany, 1990 - 2005[139]



10.2.2 Greenhouse Gas Reduction Achievable with $700 Million Photovoltaics Incentive Budget

California utilities have historically been responsible for recovering 100 percent of the cost of their transmission investments from their own ratepayers. However in 2000 the Federal Energy Regulatory Commission instituted a new cost allocation procedure for transmission projects.[140] Transmission costs for such projects are now borne proportionately by the state's three regulated utilities, SCE, PG&E, and SDG&E, regardless of the utility territory where the project is actually located. The SDG&E customer base represents approximately 10 percent of the customer base of the three utilities combined. As a result, even though the cost of SPL will be $7 billion to $8.3 billion (2010 dollars) over the financial life of the project, SDG&E customers will pay only 10 percent of this cost, $700 to $830 million, over the 40-year financial life of SPL. SDG&E customers also pay 10 percent of SCE and PG&E transmission projects.

As noted, under the current rules of transmission line cost allocation, SDG&E customers will pay $700 to $830 million of the total cost. It is therefore of value to determine how much PV could be installed in the San Diego County area with an incentive budget of $700 to $830 million, given that is the amount that these SDG&E ratepayers will be charged for the SPL.

A $700 million budget would incentivize the installation of 1,030 MW of PV without battery storage in the San Diego region by 2020. Assuming 10 percent of the $700 million incentive budget is used for energy management/battery systems and the remaining 90 percent for PV capacity, approximately 920 MW of PV capacity would be installed that is capable of operating at rated output throughout the afternoon 3 pm to 6 pm peak summertime demand period. An $830 million budget would incentivize the installation of 1,220 MW of PV without battery storage, and 1,100 MW with battery storage to maintain rated output through the afternoon peak. The distribution of the $700 million in PV incentives is shown in the PV incentive program financing plan summary tables included in **Attachment K**.

How does this projection compare to the projection for the CSI program? The objective of the CSI $2.165 billion incentive budget is to increase installed PV capacity in California to 1,940 MW by 2017. A $700 million incentive budget is one-third the CSI incentive budget of $2.165 billion. The approximate installed PV capacity that could be expected from a $700 million incentive budget under CSI would be in the range of 650 MW (without battery storage), one-third the CSI target of 1,940 MW.

10.2.3. Displacement of PV with Concentrating Solar and Wind

The overall cost of the renewable energy portfolio to achieve 50 percent greenhouse gas reduction by 2020 will decline to the degree that renewable energy parks develop in the more rural areas of San Diego County, using concentrating PV or a concentrating solar technology of similar efficiency, and these parks displace a portion of the 2,040 MW of fixed PV capacity that would result from the *San Diego Solar Initiative*. These renewable energy parks are discussed in more detail in Section 13. To the degree that wind power substitutes for this fixed PV capacity, assuming no new transmission must be built to accommodate that wind power, the cost to achieve the 50 percent greenhouse gas reduction by 2020 will drop further. Regional wind power is discussed in more detail in Section 14.

10.3 Coordinating PV Installations with Roof Replacements

Commercial and residential PV installations can be coordinated with roof replacements to maximize efficiencies. The typical service life of roofing material is 20 to 25 years. The typical guarantee period for solar panels is 25 years. Timing the PV installation with a new roof means the entire roof and PV system will have a coordinated minimum service life in the range of 25 years.

San Diego City Schools contracted the integrated re-roofing and installation of a total of 5,110 kW of PV power on fourteen schools to Solar Integrated, Inc. (Los Angeles). The contractual arrangement is a long-term power purchase agreement, where Solar Integrated owns the roofs and the PV panels. Solar Integrated manufactures the high efficiency "cool roof" (http://www.solarintegrated.com/non_pv.htm) and adds PV as a component of the roof installation.

City Schools is charged a fixed $/kWh rate for all PV power generated. This rate is significantly below the rate City Schools would otherwise pay SDG&E for utility power.[141] This is one example of a relatively painless financing and ownership model that could be employed at hundreds of commercial sites in the San Diego region if an adequate incentive budget is available. Figure 10-3 shows the San Diego Education Center equipped with a cool roof and 100 kW of rooftop PV.

Figure 10-3. San Diego Education Center with High Efficiency Roof and PV

11. Renewable Energy Tariffs: The Key is Rates that Reflect Actual Value

A fundamental assumption of SB1 and the proposed *San Diego Solar Initiative* programs is that PV costs will decline steadily over the next decade, to the point that PV will compete without incentives against natural gas-fired generation. However, there are other proven financing mechanisms available to achieve rapid renewable energy development. One of these mechanisms is a "standard offer" for this renewable power offered by the utilities that is sufficiently generous that the renewable energy power producer receives a fair return on the renewable power investment.

The use of standard offer prices for renewable energy projects is a proven model for assuring the financing of innovative renewable energy projects. Thousands of MW of renewable wind, solar, and geothermal projects were built in California in the 1980s as a direct result of the standard offer contract structure. This is the format used in the San Diego region with "qualifying facilities," larger cogeneration plants that produce steam from industrial or commercial use and power primarily (though not exclusively) for export to SDG&E.

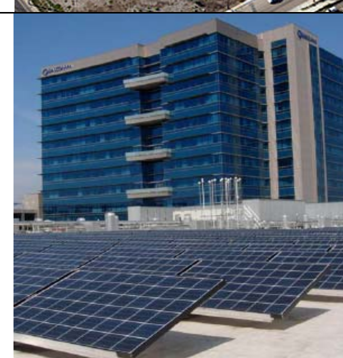
Last year 10,000 MW of wind power were installed in Europe, primarily in countries with feed-in tariffs. "Feed-in tariff" means the renewable energy producer is paid a fixed rate for the renewable power sold to the grid.

Renewable energy development in the U.S. is contingent on the federal production tax credit at present. This program has been essential in the U.S. for promoting wind power. However, it has also suffered from three principal drawbacks. First, it has been an "on again, off again" tax credit, subjecting the industry to boom and bust cycles. Second, the credit originally only applied to wind, though it was extended to other types of renewable energy in the 2005 Energy Policy Act. The two-year cycle of expiration of this tax credit creates a challenging timeframe for renewable projects other than wind. Third, it only supports projects for the first 10 years, making it less helpful than the German solar tariff which pays projects for 20 years. Twenty years is much closer to a realistic financial lifecycle for solar projects. Fourth, it only applies to commercial (private) developers who can take tax credits. Government agencies, municipal utilities like Los Angeles Department of Water and Power and Imperial Irrigation District and other non-profit entities, are ineligible.

In Europe, feed-in tariffs are set either at a fixed price, or a fixed premium above spot market prices. Price levels and premiums vary by technology, reflecting variation in technology costs. Incentives vary by country. Incentives for some technologies are scheduled to decline over time. California is currently implementing two programs with incentives similar to feed-in tariffs. As part of the CSI, the CPUC has developed performance-based incentives with set payments per kWh for qualifying solar photovoltaic systems. The CPUC is also implementing a process to determine a tariff rate that will be offered to public water or wastewater agencies for renewable generation and whether this or a similar tariff should be used to spur additional renewable resource development.

The renewable energy payments need to be fully justifiable based upon a real mix of value factors, so it is not in fact or perception a subsidy or special handout. This is the foundation for the German feed-in tariff for solar energy. The German government calculated how much solar peak energy was worth, adding up the electric value, the social value, the environmental value, and the future risk hedge value. The feed-in tariff is not a charity payment, but a payment for real value delivered. European countries that do not set tariffs high enough have not been nearly as successful as those with fixed, long-term rates that are reasonably generous.

12. Approaching Carbon Neutral Now: Local Examples of Cutting-Edge Facilities

San Diego City Schools, 5,110 kW of PV: Photo at right is the roof of the Juarez Elementary school. The PV output from this installation is 67 kW. City Schools has a long-term power purchase agreement with Solar Integrated (Los Angeles). A total of 14 schools have been re-roofed using high efficiency “cool roofs” that serve as a platform for the PV arrays. Solar Integrated owns and maintains the roofs and the PV systems. City Schools pays a flat $/kWh rate for the power generated by the PV systems. This rate is significantly below the rate City Schools would otherwise pay SDG&E for electricity.	
City of San Diego, Alvarado Water Treatment Plant: This 945 kW PV system was built via a long-term power purchase agreement with SunEdison. The city pays SunEdison $0.12/kWh, offsetting a current utility rate of approximately $0.17/kWh.	
Qualcomm Building W Campus, Sorrento Valley: The 250 kW PV array is installed on the roof of the building and the shade structure of the parking garage. The PV output is sufficient to support all lighting requirements for the building, parking structure and onsite cogeneration plant. Efficiency improvements, including high efficiency lighting fixtures, gas absorption chillers, boilers, and water heaters, have combined to reduce electricity consumption by 30 percent.	
Solara housing complex, Poway: This housing complex is the first of its kind in the state - a green-built, government-financed, affordable-housing complex that is nearly climate neutral, constructed with minimum pollution and maximum energy efficiency. The California Energy Commission subsidized the $18.5 million Solara complex to help create a working example for developers in the public and private sectors on how to build green and at low cost.	
Kyocera parking lot, Kearny Mesa: The 235 kW “solar grove” arrangement provides PV electricity to the adjacent manufacturing plant as well as shade and cover for autos in the parking lot. EnvisionSolar, a San Diego company, is now marketing solar PV systems for parking areas.	

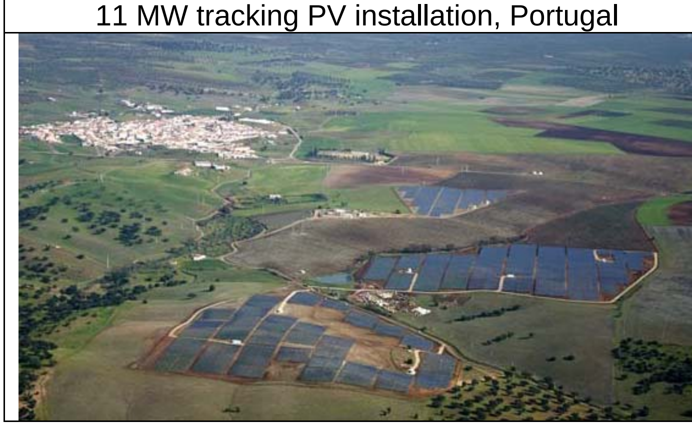
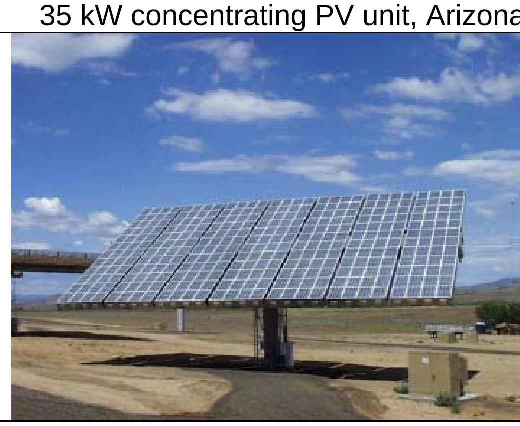
13. Concentrating Solar and Renewable Energy Parks

San Diego County is rich in solar resources. Use of concentrating solar technologies, as opposed to fixed rooftop PV, can maximize the amount of solar energy extracted from this solar resource. There are four types of concentrating solar technologies in operation or under development at this time: 1) solar trough, 2) concentrating PV, 3) dish Stirling, and 4) concentrating towers. Although not a concentrating solar technology, tracking PV has been deployed on a large scale and is fully commercial. "Tracking" means the panel or dish slowly pivots to follow the path of the sun over the course of the day. A tracking PV system generates significantly more power than a fixed PV system as a result.

Solar trough is the only concentrating solar technology that can be considered fully commercial at this time, with 354 MW of capacity in operation in California. The minimum size considered commercially viable for this technology is approximately 50 MW. A 50 MW solar trough power plant would require approximately 300 acres of flat land. As a result, solar trough technology is not a good match for the terrain or land availability realities of San Diego County.

Dish Stirling and concentrating tower technologies are still at a pre-commercial stage.[142] The San Diego Regional Renewable Energy Study Group addressed dish Stirling in its August 2005 report *Potential for Renewable Energy in the San Diego Region*.[143] Dish/Stirling is identified as pre-commercial in this study, based on analyses conducted by the National Renewable Energy Laboratory and Black & Veatch consulting engineering firm. In contrast, concentrating PV has performed well at the 1 MW pilot stage and appears ready for commercial scale-up to a 5 to 10 MW size.[144] PG&E has announced a contract for a 2 MW concentrating PV peaking power plant on 8 acres in Tracy, California.[145] Tracking PV systems are also commercial and have been built as large as 11 MW. Photos of an 11 MW tracking PV array in Portugal, and of a concentrating PV unit operating in Arizona, are provided in Figure 13-1. PG&E has also announced an agreement for 5 MW of PV on 40 acres near PG&E's Mendota substation in Fresno County.[146]

Figure 13-1. Tracking PV Array and Concentrating PV Unit

11 MW tracking PV installation, Portugal	35 kW concentrating PV unit, Arizona
	

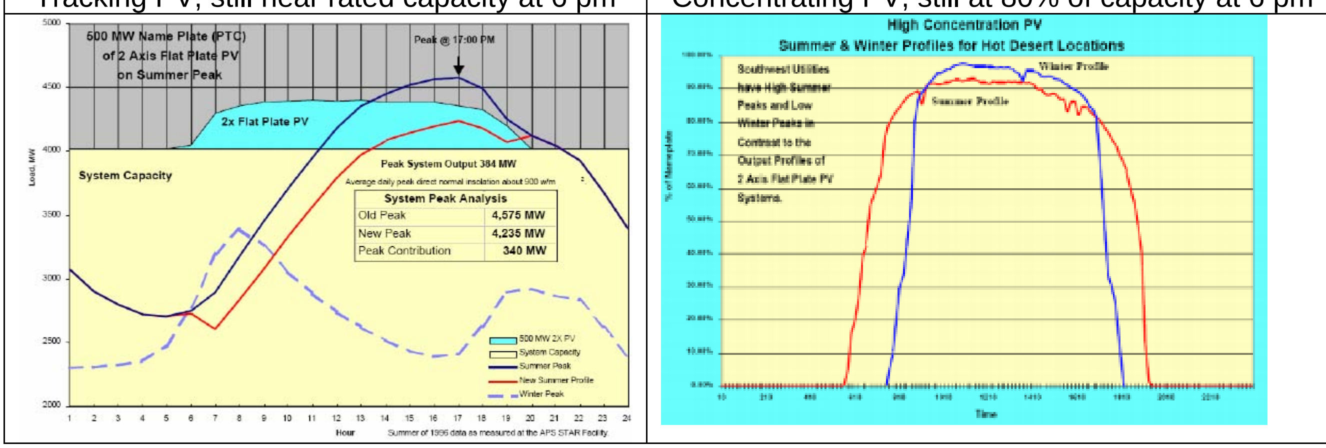
San Diego County has few areas that are amenable to the land requirements necessary for a commercial-scale solar trough power plant. To address this reality, the concept of "renewable energy parks" has been developed to best match the topography and land use of more rural areas of San Diego County with appropriate solar options.[147] This concept entails the deployment of many smaller concentrating PV or tracking PV arrays in the 1 to 10 MW size on commercially-available land near existing SDG&E transmission lines and substations. SDG&E owns a network of 69 kV transmission lines that serve the rural areas of the county. Power from these renewable energy parks would be delivered over the 69 kV grid to developed areas of the county.

A credible and inclusive stakeholder process will be necessary to establish ground rules for identifying acceptable renewable energy park parcels. Many of the residents and landowners in the backcountry of San Diego County are there because it is rural and relatively undeveloped and would prefer that it remain that way. These are the people that will be most directly impacted by the renewable energy parks. However, many of these same residents are aware of the need to move quickly to address climate change and greatly increase renewable energy production. The inclusive stakeholder process used to develop the *RES 2030* is an example of the type of stakeholder process that could be used to cooperatively identify the most suitable sites for renewable energy parks. Without such a stakeholder process, the development of renewable energy parks in the backcountry will almost certainly experience delays and unnecessary controversy.

The power generation profile of concentrating PV and tracking PV closely match the daily power demand profile. See Figure 13-2. As a result, both of these technologies are good candidates to serve as peaking power supplies on hot summer days. The CEC recently compared the lifecycle cost of a host of power generation technologies and determined the lifecycle cost of power generation from concentrating PV is considerably lower than the cost of generation from a peaking gas turbine.[148] This further reinforces the advisability of the development of a renewable energy park using concentrating PV or tracking PV to demonstrate that such installations can serve as reliable peaking units on the hottest summer days (when the sun is always shining).

Figure 13-2. Daily Power Generation Profiles of Concentrating PV and Tracking PV

Tracking PV, still near rated capacity at 6 pm	Concentrating PV, still at 80% of capacity at 6 pm

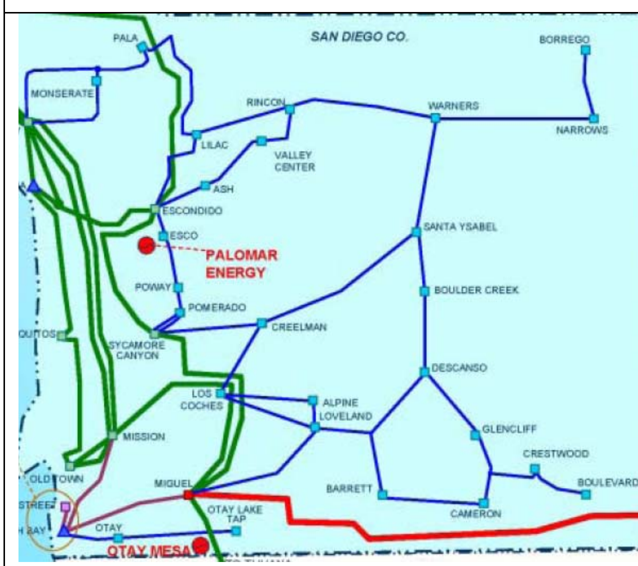


The existing 69 kV system should be capable of handling hundreds of MW of power generation from individual 1 to 10 MW solar installations in rural areas of the county. Should these renewable parks develop rapidly, the capacity of the 69 kV system can be approximately doubled by reconductoring the existing lines with commercially available high temperature, low sag conductor technology. The location of these 69 kV lines is shown in Figure 13-3a. The capacity of the 69 kV system in East County, which consists of four separate existing 69 kV lines, could be increased to the range of up to 1,000 MW total via reconductoring and transformer substation upgrades.[149] Increasing the voltage of the 69 kV grid would also be a consideration if growth of the renewable parks began to approach the capacity of an upgraded 69 kV system. Reconductoring with high temperature, low sag conductors is also an option for transmission lines with voltages up to 230 kV.

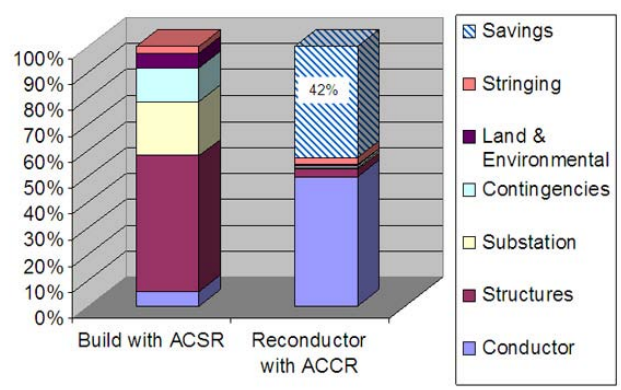
One type of high temperature, low sag conductor is manufactured by 3M Company. SDG&E has a test section of the 3M high temperature, low sag conductor on an existing 69 kV line.[150] According to data provided by 3M, it is significantly less expensive to replace the wire on an existing 69 kV line with this type of high temperature, low sag conductor than to build a new 69 kV line. The relative cost of reconductoring an existing 69 kV line compared to a new 69 kV line is shown in Figure 13-3b.

Figure 13-3. Existing SDG&E 69 kV Grid and Relative Cost of a New Stand-Alone Transmission Line Versus Reconductoring with Composite Line to Double Capacity[151,152]

a. Existing SDG&E transmission lines: 69 kV (blue), 230 kV (green), and 500 kV (red)



b. Reconductoring versus new conventional transmission line to achieve same capacity increase: 42 percent cost savings



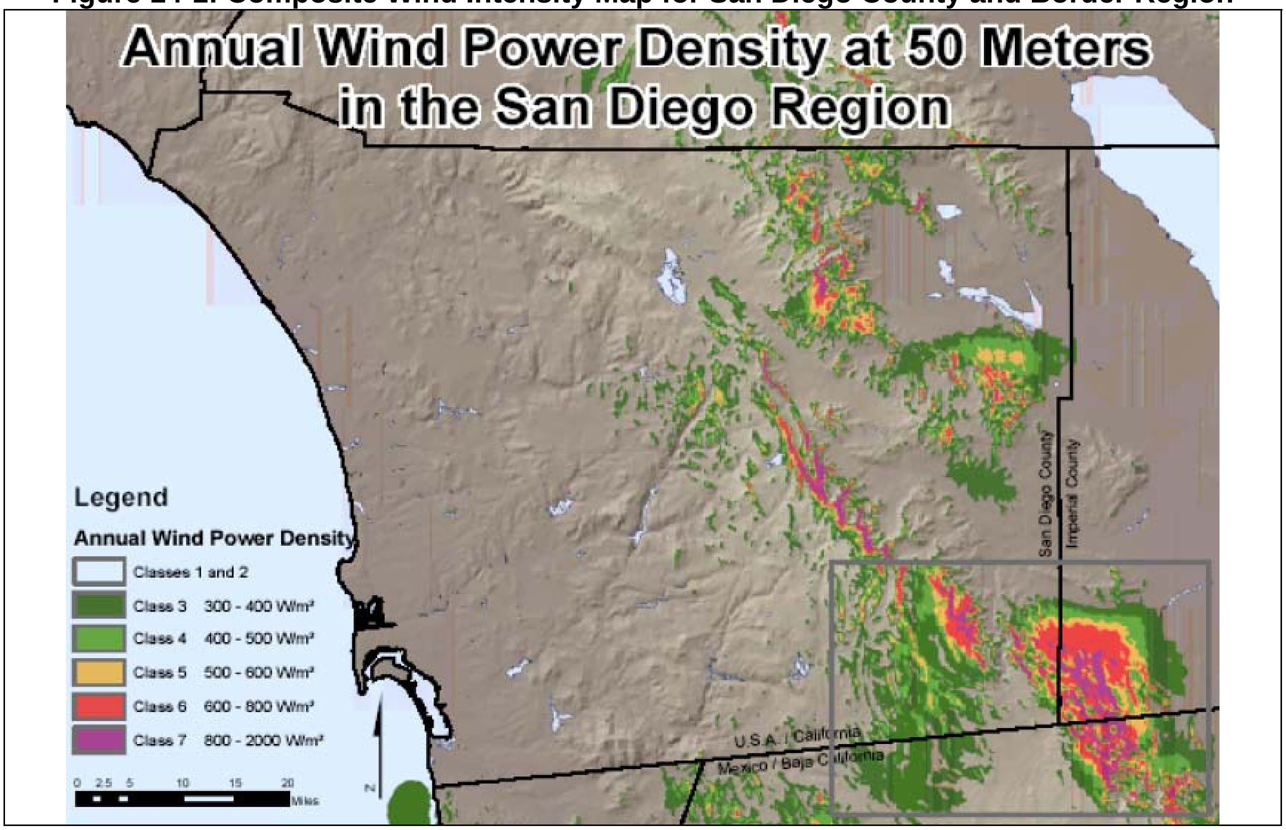
ACSR: aluminum conductor steel reinforced (conventional); ACCR: aluminum conductor composite reinforced

14. Utilizing the Wind Resource – What Are the Tradeoffs?

The regional wind resource is excellent, with a combined potential of 1,650 to 1,830 MW in eastern San Diego County and across the border in Baja California.[153] The high wind resource locations are shown in Figure 14-1. SDG&E has a power purchase agreement with a 50 MW wind farm located 60 miles east of San Diego. Fenosa, a Spanish firm, recently announced plans to develop a 500 MW wind farm just across the border in an area of Baja California called La Rumorosa. The power will be exported to California. Sempra Energy has announced the company has purchased co-development rights for 250 MW of wind power in La Rumorosa as well, and that this power will be imported along SDG&E's existing 500 kV Southwest Powerlink (Southwest Powerlink is the red line along the border in Figure 13-3a).[154]

Wind power is a fully commercial technology and is cost-effective, in the range of $0.05 to $0.07/kWh.[155] However, the regional wind resource is strongest is at night and in non-summer months when electricity demand is relatively low. The wind resource tends to be weakest on summer days, when demand is highest. The high value wind resource sites also tend to be located in areas of spectacular natural beauty that are among the last large regional undisturbed habitats of a number of threatened and endangered species. This means that locating large wind farms in San Diego County will be controversial unless there is a credible preliminary process, similar to the process described previously for renewable energy parks, which identifies selected areas that are suitable and other areas that should be off-limits to wind projects.

Figure 14-1: Composite Wind Intensity Map for San Diego County and Border Region



Wind power is considerably less capital intensive than PV on a MW basis. The inclusion of a significant amount of wind power to reach the 50 percent GHG reduction target by 2020 would result in lower cost to reach the goal than a strategy based exclusively on PV. In addition to the 500 MW Fenosa project just over the border, wind developers have requested transmission access for over 800 MW of wind projects in eastern San Diego County. This is a total of approximately 1,300 MW of wind capacity. If half this wind capacity gets built to serve the San Diego area, approximately 600 MW, this new wind energy will provide about 10 percent of the San Diego region's energy needs in 2020 and about 20 percent of the targeted GHG reduction.

This quantity of wind power would equal the annual energy output of approximately 1,000 MW of PV capacity.[156]

However, no peak power demand contribution can be assigned to the regional wind resource. As noted, the wind trends to be strongest in evening hours and non-summer months. Effective energy storage would be necessary for wind power to reliably contribute to meeting peak power demand. Practical solutions to this challenge are: 1) pumped storage between reservoirs of different elevations in the county, 2) utility-scale battery storage with sodium-sulfur batteries, or 3) the advent of large numbers of plug-in hybrid vehicles that would allow wind energy feeding into the grid at night to charge vehicles. These vehicles would be plugged into the grid during the day when the owner is at work and would be available to feed back into the grid to meet rising demand during the day. These energy storage options are discussed in more detail in Section 15.

15. Energy Storage – Maximizing Renewable Energy Benefits

Energy storage systems allow intermittent renewable energy to be stored and used during periods of peak demand and highest electricity rates. Energy storage also allows work to be done during periods of low demand and low electricity prices. One example is the production of chilled water or ice for air conditioning systems in the evening for use during the peak demand period the following day, to reduce peak energy demand and avoid paying peak electricity prices. These systems are briefly described in the following paragraphs.

15.1 Battery storage for fixed rooftop PV

The electricity production from fixed rooftop PV systems typically declines by 3 pm. Yet the peak demand generally occurs in the 3 pm to 6 pm period. Therefore, only a portion of the PV system's capacity is available during the period of greatest demand. However, by adding a modest amount of battery storage to the system, 2 to 3 hours, the PV system can consistently supply power at or near its rated capacity during the afternoon peak. SCE is currently conducting a demonstration test of rooftop PV systems equipped with Gaia Power Tower energy management/battery storage systems operating as peaking power systems.[157] Adequate battery storage makes PV a much more valuable contributor to meeting peak demand than a fixed system with no battery storage.

Battery storage systems built with PV systems are eligible for the same tax credits as the PV systems.[158] These battery systems represent dependable power that can be dispatched by the utility during periods of peak demand and recharged at night when demand and prices are low. Adding limited battery storage to PV systems is today's off-the-shelf equivalent to what the plug-in hybrid automobile may be one day in the future. SDG&E is currently proposing a critical peak rate of $1.20/kWh. Battery storage will rapidly pay back in a dynamic pricing environment where battery power receives a critical peak price premium.

15.2 Large-scale utility battery storage

The Japanese are investing heavily in high-temperature, sodium-sulfur batteries for utility load-leveling applications. Approximately 150 MW of utility peak-shaving batteries are in service in Japan. American Electric Power, whose subsidiaries include electric utilities in the Indiana, Ohio, West Virginia area, is planning to install 35 MW of peak shaving sodium-sulfur batteries by 2017. Large-scale battery storage options are discussed in detail in **Attachment L**.

15.3 Thermal energy storage for air conditioning systems

Air conditioning systems that include thermal energy storage dramatically reduce the peak electrical demand of these systems. As noted above, thermal energy storage, in the form of cold water or ice, also allows work to be done during periods of low demand. This reduces peak energy demand and minimizes peak electricity prices paid by the owner. **Attachment H** includes a pair of thermal energy storage diagrams that explain how chilled water and ice thermal energy storage systems work.

15.4 Pumped hydroelectric storage for wind power

San Diego has one major pumped storage project, the Lake Olivenhain-Lake Hodges 40 MW project. Lake Olivehain is located at a significantly higher elevation than Lake Hodges. Water will be pumped from Lake Hodges to Lake Olivenhain during periods of low electricity demand, generally at nighttime, and sent from Lake Olivenhain to Lake Hodges by gravity to drive a hydroelectric turbine during periods of high electricity demand. A description of this project is provided in **Attachment M**.

15.5 Plug-in hybrid cars as peaking power plants

Plug-in hybrids could also fill the role of peaking power plants during periods of high demand. Battery-powered cars would serve as storage for energy generated in the evening, a period of relatively low demand and low electricity prices, and would discharge the power at peak demand times from a two-way electrical connection in the parking garage.

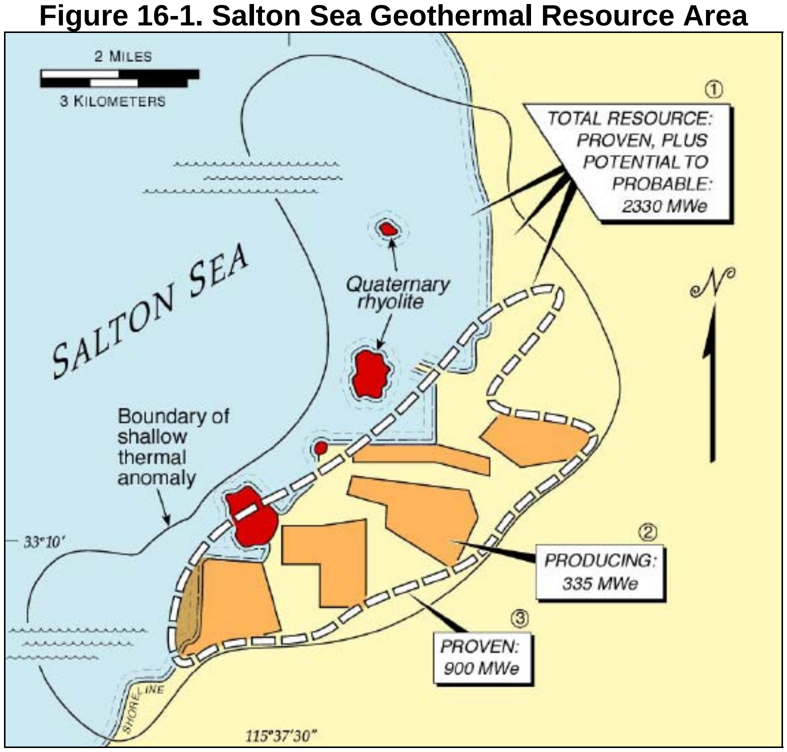
Google and PG&E will test six Toyota Prius and Ford Escape hybrid vehicles modified to run partly on electricity from the power grid.[159] One vehicle has been modified to send electricity back to PG&E. This test takes the hybrid a step further by using extra batteries to hold spare energy. PG&E will send wireless signals to the car while it is parked and plugged-in to determine its state of charge. PG&E can then recharge the batteries or draw out power. If there were thousands of such vehicles connected to the grid, the utility could store power produced in slack hours until it was needed at peak times.

The South Coast Air Quality Management District, which covers the entire greater Los Angeles-Long Beach-Riverside areas, is recommending the deployment of 100,000 plug-in hybrids by 2014 and up to 1,000,000 by 2020 in its 2007 Air Quality Management Plan.[160]

16. Geothermal Power – Is It Sustainable?

The geothermal resource in Imperial County is also significant, with a near-term potential of 800 MW.[161] Approximately 400 MW of geothermal power is already in production in Imperial County. The primary geothermal resource is located at the south end of the Salton Sea. See Figure 16-1. A major advantage of geothermal power is that it is available 24 hours a day, 7 days a week, in contrast to intermittent solar and wind resources. The cost of power production is also relatively low, in the range of $0.05 to $0.07/kwh.[162] However, the geothermal fluid in Imperial County is very high in solid content, approximately 20 percent, and these solids contain a high concentration of metals. The principal geothermal developer in Imperial County, CalEnergy, briefly experimented with refining zinc from the geothermal solids several years ago. Low zinc commodity prices made the zinc refining operation unprofitable and it was discontinued.

Figure 16-1. Salton Sea Geothermal Resource Area



Geothermal plants in the Imperial Valley are also large consumers of water. This water is primarily consumed in the evaporative cooling towers that are used to condense the geothermal steam after it passes through the power turbine. Much of the water used in the cooling tower is condensed geothermal reservoir fluid. This is geothermal fluid that does not get recycled back into the geothermal reservoir to maintain reservoir pressure. A concern with this approach is that as more and more geothermal plants are built in Imperial County, the pressure in the geothermal reservoir(s) may go into permanent decline and a potentially sustainable resource may become unsustainable.

This issue can be addressed by using a combination wet-dry cooling system that would reduce cooling tower water consumption by 80 to 90 percent. However, geothermal plants are very expensive to build. These plants will not be built to minimize the consumption of geothermal fluid in the cooling towers without state regulations that require minimum water use in geothermal plant cooling systems. It is unclear whether geothermal power development in Imperial County can be considered sustainable given the unknowns surrounding the impact of increasing consumptive use of geothermal fluid for evaporative cooling as more geothermal plants are built.

17. Rapid Expansion of Combined Heat and Power

Distributed generation systems are any power generators that generate power at the point of use. These systems can be renewable energy, such as rooftop PV, or highly efficient natural gas-fired "combined heat and power - CHP" systems. CHP have the lowest GHG footprint of any fossil fuel power generation system (639 lb CO_2 per MWh, compared to 819 lb CO_2 per MWh for combined cycle power plants and 1,170 lb CO_2 per MWh for peaking gas turbine power plants).[163]

Another benefit of CHP and other forms of distributed generation when compared to bulk transmission or central station power plant additions is reducing the consequences of single-point failures related to the outage of large transmission lines and power plants. Reducing exposure to system failures increases the overall security of local energy supply.

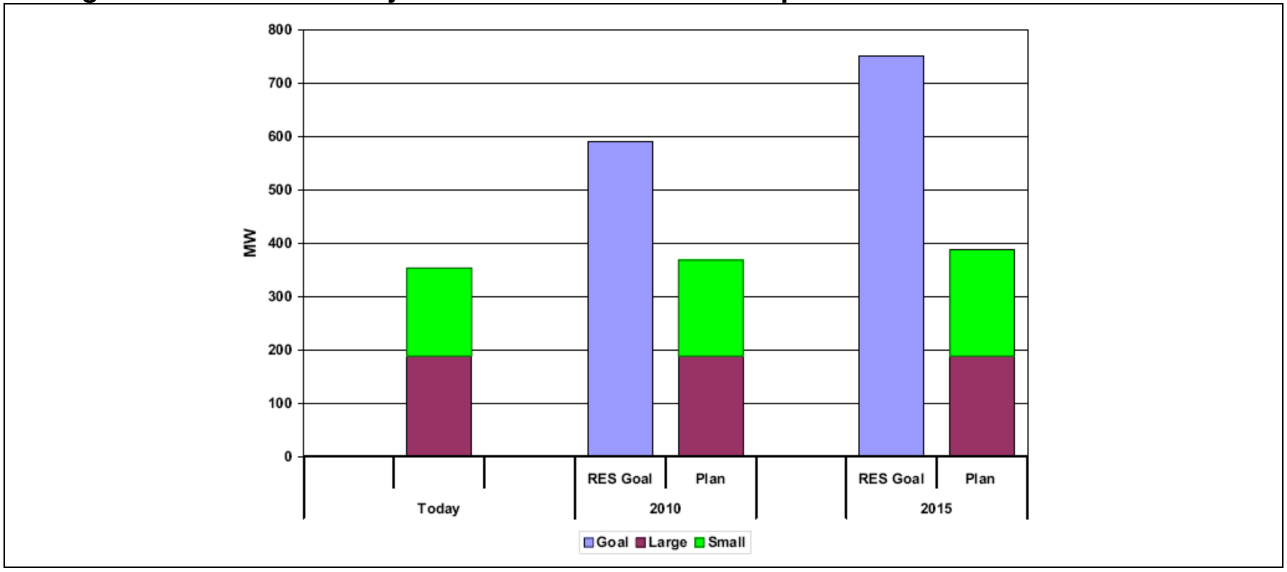
CHP facilities typically produce in the range of 1 to 20 MW of electric power. The hot exhaust gases from the combustion process, a small gas turbine or stationary reciprocating engine, are used to make steam or hot water for onsite use. The steam can be used for both heating and cooling. For example, steam can be used to drive a highly efficient centrifugal chiller to provide cooling in summer. That same steam can be used as a source of heat in winter, or by onsite processes that require steam.

Rapid expansion of CHP power generation is a priority goal in the *Energy Action Plan*. *Energy Action Plan II* states (p. 9): "*Develop tariffs and remove barriers to encourage the development of environmentally-sound combined heat and power resources and distributed generation projects*." The *Energy Action Plan* prioritizes CHP over large central power plants.

RES 2030 calls for 1,100 MW of CHP by 2020. There are currently less than 400 MW of CHP capacity in the San Diego region. Achieving the *RES 2030* target of 1,100 MW CHP capacity by 2020 means 700 MW of CHP must be added in the region. This is the equivalent of a "virtual" South Bay Power Plant replacement in terms of MW capacity, and would negate the need to construct another baseload power plant in the region.

The CEC "road map" for CHP development calls for CHP to provide 25 percent of peak load by 2020. SDG&E is projecting a peak load in 2016 of 5,060 MW. Twenty-five percent of 5,060 MW is 1,265 MW. Yet SDG&E projects almost no increase in CHP capacity over the next decade.[164] SDG&E estimates total large and small CHP at approximately 390 MW in 2015 as shown in Figure 17-1 (SDG&E projections are the green and purple bars labeled "Plan").[165] This is in contrast to the *RES 2030* goals of 590 MW of CHP by 2010 and 1,100 MW of CHP by 2020.

Figure 17-1. SDG&E Projected CHP Generation Compared to CHP Goals in RES 2030



The CEC indicates that significant energy policy changes will be necessary to accelerate the development of CHP in California. The March 2007 *Distributed Generation and Cogeneration Policy Roadmap for California* report prepared by CEC staff calls for ten more years of subsidies for distributed generation technologies.[166] These include incentive payments for CHP under the CEC's self-generation program. Making such policy changes, according to the report, could turn distributed generation from a nascent technology that makes 2.5 percent of peak power to a significant provider that meets 25 percent of the state's peak power needs by 2020.
Among the changes envisioned by the CEC to generate a quarter of the state's power from off-grid distributed generation are transparent dynamic rates for electricity. The report also recommends removing institutional barriers. For instance, distributed generation has been hampered by a lack of uniform rules and standards that could speed installation of equipment.

There are approximately 240 candidate sites for conventional CHP facilities in San Diego County.[167] These include large private employers, large city and county government centers, military bases, large hospitals, large hotel complexes, large shopping complexes, and large universities and colleges. Some of these sites already operate CHP plants, such as the University of California San Diego, San Diego State University, Children's Hospital, and Qualcomm.

A number of relatively large cogeneration (power and steam) plants are also located on military bases in the San Diego area and sell power to SDG&E. These plants are known as "qualifying facilities" and date from the 1980s. These plants "qualified" for a financially attractive electric rate, known as the Standard Offer 4 (SO-4) contract, which was developed in California to promote the construction of high efficiency cogeneration plants and renewable energy resources. The utilities were required to purchase all power generated by these facilities under the terms of the SO-4 contract.[168]

Utility tariffs more favorable to distributed generation are needed according to the March 2007 CEC policy roadmap. A favorable rate structure that accurately reflects the benefits of CHP is essential to expand the development of CHP in the San Diego area. SDG&E's proposed critical peak pricing tariff of $1.20/kWh is an example of a tariff that would greatly improve the economics of CHP.[169] This rate would apply for up to 126 hours per year. A CHP plant selling 2,000 kW to SDG&E for 126 hours at $1.20/kWh would receive $302,400 in revenue in return. The cost of fuel to provide this power would be in the range of $15,000 to $20,000.[170]

Applying a favorable tariff, like the PG&E A-6 tariff, to CHP in the San Diego region would also dramatically improve the financial attractiveness of CHP. The summer peak A-6 tariff is $0.319/kWh (see Table 10-2). The summer peak in SDG&E service territory is May 1 through September 30, from 11 am to 6 pm, a total of 1,071 hours per year. The total revenue from generating 2,000 kW at the A-6 rate for 1,071 hours is $683,000. The fuel cost to produce this power would be in the range of $150,000, leaving over $500,000 in net revenue. The revenue generated from power sales at the peak rate alone would nearly cover the financing of the CHP plant.[171]

SDG&E must also take all the excess power generated by CHP facilities to maximize the benefit of these plants to the region and to ensure the plants are operating at maximum efficiency. SDG&E recently established a precedent for taking excess power from CHP facilities when the company signed a contract in October 2006 to take excess power from the Children's Hospital CHP plant.

The SDG&E prohibition on CHP plants supplying power to adjacent buildings under different ownership creates an artificial barrier to CHP development in San Diego County as well. Similar facilities that individually are too small to support a dedicated conventional CHP plant, such as medium-sized hotels or commercial office buildings, are often clustered together. CHP would be significantly more cost-effective and fuel efficient if these "clusters" could be served by the same conventional CHP plant. This impediment must be addressed if the goal of adding 700 MW of CHP by 2020 is to be realized.

Smaller scale CHP options are now also available. The Sheraton Hotel and Marina on Harbor Island has a long-term agreement with Alliance Power for 1.5 MW stationary fuel cell power plant that supplies 70 percent of the hotel's electric power demand. The waste heat from the units is used to heat swimming pools and for domestic water heating. The plant consists of two fuel cells, a 1 MW unit and a second 0.5 MW unit. The 1 MW unit went online in December 2005, the 0.5 MW unit in mid-2006. A description of this project is provided in **Attachment N**.

Microturbines combined with absorption chillers are another example. United Technologies markets microturbine-absorption chiller packages under the trade name "PureComfort®." Systems are offered at 240 kW, 300 kW, and 360 kW. The hot exhaust gas is utilized in an absorption chiller/heater. The efficiency of this system can reach 90 percent. PureComfort® systems are installed at the Reagan Library in Simi Valley, California and the Ritz-Carlton Hotel in San Francisco.[172] The availability of such small CHP packages greatly expands the potential number of candidate CHP facilities in San Diego County.

18. Natural Gas-Fired Gas Turbine Generation – Where Does It Fit?

Natural gas-fired combined-cycle and peaking gas turbine capacity will be necessary to provide power at night and during periods of cloudy or inclement weather in 2020. These conventional generation assets will also be needed to provide reliability support as experience is gained in San Diego with greater and greater levels of intermittent renewable energy power. There will not be a need for new utility-scale base load generation, beyond the 542 MW Palomar Energy and 561 MW Otay Mesa combined-cycle projects, if the deployment of CHP and PV systems meet the capacity targets in *San Diego Smart Energy 2020*.

The CEC has determined that California's combined-cycle population operates with an average capacity factor between 53 and 61 percent on average.[173] SDG&E's two combined-cycle plants will be needed to provide power in the evenings in 2020. It is possible that the capacity factor of these two plants in 2020, as a result of operating in this "load following" pattern,[174] will be comparable to the average capacity factor of California combined-cycle plants today.

By 2020 the San Diego region will be exporting considerable amounts of power during the day when the PV systems and CHP plants are operating at or near capacity. The average daytime load is likely to fluctuate between 2,000 and 2,500 MW in 2020 under *San Diego Smart Energy 2020*, yet the combined capacity of the PV systems and CHP will be approximately 3,400 MW.[175] This means daytime power generation in the San Diego area from PV and CHP will exceed demand. This power will be exported to neighboring utility districts during these times on the existing transmission system. At night only the CHP plants will be operating, and output from these plants will 1,000 MW or less. Yet the average nighttime load is likely to be in the range of 1,500 to 2,000 MW. This will require that combined-cycle plants make up the difference.

The net effect of this diurnal cycling between PV and combined-cycle in 2020 will be that slightly more combined-cycle power is used in the San Diego region, approximately 500 GWh per year, than PV power is exported to neighboring utility territories.

19. Getting Maximum Benefit from the Existing Transmission Grid

19.1 Start from the Bottom Up: Modernize the Distribution Grid

The electricity distribution system is the relatively low voltage system, 12 kV and less, that directly serves neighborhoods and commercial areas. SDG&E'S electricity distribution system includes 264 distribution substations, 977 distribution circuits, 231,112 poles, 9,351 miles of underground system, 6,712 miles of overhead systems, and various other pieces of distribution equipment. SDG&E has an aging infrastructure problem across broad categories of transmission and distribution equipment.[176]

The single largest quantity of SDG&E transformers was installed in the 1950's. Many of these transformers are either approaching obsolescence or are obsolete due to excessive maintenance requirements, operational limitations, lack of spare parts, and deteriorating condition. Aging infrastructure affects not only substation transformer banks but also wood poles and underground cable. Approximately 30 percent of SDG&E's wood poles have been in service for at least 50 years, and approximately 48 percent have been in service for 40 years. Polymeric cables remain a large contributor to SDG&E's aging infrastructure problem, in particular cables installed prior to 1983. The pre-1983 vintage cables were manufactured with poorer manufacturing processes and much less quality controls and typically did not have a jacket. SDG&E continues to invest significant capital and resources to maintain these groups of cables.[177]

Aging SDG&E distribution infrastructure continues to demand more and more maintenance and repair resources. As the age of equipment increases the amount of maintenance necessary also increases. So does the probability of failure in-service. Aging equipment becomes obsolete due to wear, technology advancements, and lack of availability of replacement parts. A large amount of SDG&E'S distribution equipment is reaching the end of its useful life.

SDG&E has correctly identified that the weakness in the transmission system is at the distribution level, the interface with homes and businesses. The immediate need is a complete overhaul of the 12 kV distribution system. This is the appropriate time to invest in a revitalization of the SDG&E distribution system using "smart grid" technological innovations.

The smart grid concept was developed by the U.S. Department of Energy's Modern Grid Initiative. To address aging transmission and distribution infrastructure, the Modern Grid Initiative seeks to create a modern – or "smart" – grid that uses advanced sensing, communication, and control technologies to generate and distribute electricity more effectively, economically and securely. Smart grid integrates new innovative tools and technologies from generation, transmission and distribution to consumer appliances and equipment.

San Diego-based SAIC evaluated the benefits of implementing a smart grid in the San Diego area in 2006.[178] The benefits identified by SAIC include:

- Reduction in congestion cost.
- Reduced blackout probability.
- Reduction in forced outages/interruptions.
- Reduction in restoration time and reduced operations and maintenance.
- Reduction in peak demand.
- Other benefits due to self diagnosing and self healing.
- Increased integration of distributed generation resources and higher capacity utilization.
- Increased security and tolerance to attacks/natural disasters.
- Power quality, reliability, and system availability and capacity improvement due to improved power flow.
- Job creation and increased gross regional product.
- Increased capital investment efficiency due to tighter design limits and optimized use of
- grid assets.

- Tax savings for the utility from a depreciation increase.
- Environmental benefits gained by increased asset utilization.

If all thirteen smart grid improvement initiatives identified by SAIC for the San Diego region are implemented, the initiatives would generate $1.4 billion in utility system benefits and nearly $1.4 billion in customer benefits over 20 years.

19.2 Existing 230 kV and 500 kV Corridors: Low Cost Upgrades Buy Big Benefits

SDG&E has two major existing transmission import corridors. Each of these corridors can be upgraded economically to provide more reliability support to the SDG&E transmission system.

Five 230 kV lines, collectively known as "Path 44," provide north-south transmission from the San Onofre Nuclear Generating Station substation, on the property of Camp Pendleton Marine Corps Base, into the San Diego urban area. The emergency transmission capacity of Path 44 is 2,500 MW. Emergency capacity in this case means the capacity when the largest import transmission line into the San Diego area, the 500 kV Southwest Powerlink (SWPL) with a rated capacity of 1,900 MW, is temporarily out-of-service.

Path 44 rating plays a key role in determining SDG&E power reliability needs. The Utility Consumer's Action Network (UCAN) has proposed that SDG&E take the actions necessary to upgrade Path 44 to allow emergency import limit for Path 44 from 2,500 MW to 2,850 MW. This upgrade would reduce SDG&E's local power reliability needs by 350 MW. UCAN estimates $111 million would be necessary to upgrade the Path 44 import capability by 350 MW.[179]

SDG&E's east-west SWPL transmission line is rated at 1,900 MW, but is currently limited to 1,450 to 1,750 MW due to transformer emergency overload concerns at the Miguel substation. The Miguel substation is the western terminus of SWPL. It is located several miles to the southeast of San Diego. There are two 230 kV/500 kV transformers at the Miguel substation. SDG&E's concern is that the outage of one 230 kV/500 kV transformer at Miguel would cause the adjacent transformer to exceed its emergency rating. One simple method to avoid this risk is to plan in advance that, if imports are above the current import limit, which varies hourly between 1,450 MW and 1,750 MW, and one transformer fails, then the other transformer will automatically be shut down as well.

SDG&E forecasts that there will be 400 to 1,400 hours per year in the 2010 to 2020 period when power imports along SWPL to Miguel will be constrained if SPL is not built. Modifying Miguel substation transformer operations in response could save millions of dollars almost immediately. This would more than cover the implementation cost of a more complex transformer operating procedure. The cost of increasing the import limit across the Miguel transformers to 1,900 MW is essentially zero using this approach. UCAN also estimates that the incremental cost to increase Miguel outlet capacity to 2,100 MW would be between $4 and $35 million. This is a situation where significant incremental transmission benefits can be obtained for a low incremental cost.[180]

20. Staying On Track: Loading Order and Distributed Generation Policy Initiatives

The SANDAG Energy Working Group is actively promoting legislation that would: 1) direct the CPUC to refine its current utility ratebasing policies to better reflect and support the *Energy Action Plan* loading order, and 2) direct the CEC to continue incentives for CHP installations.[181] The September 20, 2007 decision in the CPUC energy efficiency proceeding has initiated the process of bringing utility financial incentives into alignment with the loading order.[182] Two bills currently moving through the Legislature, AB 1064 (Lieber), the Self Generator Incentive Program extension legislation and AB 1613 (Blakeslee), Waste Heat and Carbon Emissions Reduction Act, could impact the rate of CHP development in California if they are passed into law.

The concept of the loading order is not unique to California. This same approach, prioritizing a package of energy efficiency, demand response, and distributed renewable and CHP generation measures, is currently being advocated in Maryland by a coalition of clean energy developers, including Solar Turbines, as a cost-effective alternative to a proposed $1.8 billion transmission line. The proposed transmission line would import coal power to meet a projected demand growth of 1,800 MW. The Maryland case is addressed in this section.

20.1 Aligning Utility Incentives with Energy Action Plan

The Energy Working Group has recommended the passage of legislation directing the CPUC to open a new proceeding to review and refine its existing utility infrastructure ratebasing policies to better align its policies with the loading order in *Energy Action Plan II*. The loading order described in *Energy Action Plan II* is shown in Figure 20-1. The new legislation would direct the CPUC to develop appropriate new utility shareholder penalties and revenue opportunities for failing, meeting, or exceeding *Energy Action Plan II* loading order goals and targets.

Figure 20-1. Aligning Utility Financial Incentives with Loading Order

CA Resource Loading Order	Proposed Change
Energy Efficiency	Highest ROI
Demand Response	⇑
Renewables	Sliding Scale
Distributed Generation	⇓
Fossil-Fuel Power Plants and Related New Transmission	Lowest ROI

Current CPUC ratebasing policies provide utility shareholder incentives for the bottom of the loading order, utility-scale power plants and new transmission, but offers no shareholder revenue earning opportunities for energy efficiency, demand response, renewables, and distributed generation at the top of the loading order. This runs counter to state energy priorities and needs to be revisited by the CPUC.

The September 20, 2007 CPUC decision in the energy efficiency proceeding (R.06-04-010) has restored energy efficiency program performance-based shareholder penalties and rewards that were dropped by the CPUC in 2002. However, this proceeding is not considering any changes in current ratebasing policies, and would not address the other priorities listed in the loading order. The CPUC has not reviewed or refined its current utility ratebasing policies since 2003, the year the original *Energy Action Plan* was adopted.

The legislature and the CPUC must reorient the existing utility incentives if energy efficiency, renewable energy, and distributed generation are to be prioritized over the traditional utility steel-in-the-ground approach. The financial motivators need to be realigned so that utilities profit by supporting the *Energy Action Plan* loading order, and are penalized if they do not.

20.2 Extend Incentive Program for Clean Distributed Generation

In most parts of the U.S. and the world, CHP is recognized as an efficient and environmentally advantageous technology. Clean natural gas CHP:

- Achieves combined electric and thermal efficiencies from 60 to 90 percent.
- Avoids and or defers the need to build costly electric transmission and distribution infrastructure.
- Eliminates or reduces transmission and distribution losses, reduces or eliminates grid congestion.
- Significantly decreases GHG emissions relative to any other type of natural gas combustion.

Incentives for CHP are important to accelerate projects, to offset the many institutional and utility obstacles that are still present, and to help support industry investment in low emission technology. A 2005 CEC assessment of CHP concluded that continuation of the Self Generator Incentive Program would increase CHP by more than 40 percent over the next 15-year period, with natural gas engines and turbines accounting for an overwhelming share of the new capacity additions.

The current Self Generator Incentive Program expires on December 31, 2007. The proposed legislation would direct the CPUC in consultation with the CEC to administer a Self Generation Incentive Program for ultra-clean and low-emission fossil-fuel CHP technologies, and waste gas fueled generation, that would commence on January 1, 2008, and continue to January 1, 2012.

However AB 1064 (Lieber), the Self Generator Incentive Program extension legislation in the Assembly, no longer includes a continuation of incentives for conventional CHP. This CHP component was deleted in committee.[183] Starting January 1, 2008, only fuel cell and wind technology will be eligible for incentives in statute. Unless the incentives for conventional CHP are reincorporated in AB 1064, this legislation will not assist in accelerating the construction of CHP capacity in San Diego County.

AB 1613 (Blakeslee), Waste Heat and Carbon Emissions Reduction Act, would encourage the construction of CHP in California if it is passed into law. This legislation would establish that the conversion of waste heat to electricity or other useful energy application is an efficiency measure for purposes of the loading order. The objective of the legislation is to add 5,000 MW of new CHP by 2015 in California.[184] This bill is awaiting Governor Schwarzenegger's signature as of October 10, 2007.

20.3 Distributed Generation as Alternative to New Transmission – Maryland Case Study

The Maryland Public Service Commission is currently evaluating a proposed 290-mile transmission line that would import power from West Virginia to Maryland. A major justification for the line is a concern over transmission congestion as electricity demand increases over time. Maryland recently signed into law legislation to add 1,500 MW of solar energy over the next 15 years. A coalition of clean energy developers is advocating that the Commission undertake a thorough study of specific renewable energy, clean CHP, and demand management "smart grid" measures as an alternative to the proposed transmission line.[185]

The clean energy coalition asserts in its August 17, 2007 letter to the chairman of the Maryland Public Service Commission that:[186]

> *We believe that this accelerated, continuous development (of peak-coincident solar energy, high efficiency distributed generation, and "smart grid" technologies) could be achieved at a ratepayer cost less than the proposed $1.8 billion with significantly reduced delivery and financial risk as compared to a single massive transmission corridor. Further, these resources would bring low-emissions generation capability into Maryland. The choice is between expending ratepayer funding on low-risk, low-emissions distributed generation, or relying on a single, controversial, high risk project that will only enable the export of our energy dollars to produce air pollution upwind.*

The Maryland clean energy industry coalition letter is provided in **Attachment O**.

21. Accommodating Growth – New Construction Must Account for Its Own Energy Needs

New construction in San Diego must "carries its own weight" in terms of electric energy demand. This can be achieved by requiring that new construction meet most or all of its projected electric energy demand through use of rooftop PV. This does not mean that new construction will necessarily be burdened with additional costs. For example, the PV program described in this report would result in lower electricity costs than purchasing electricity from SDG&E.

Numerous home builders in the Central Valley are incorporating rooftop PV into all new home construction as a standard feature.[187] This should be a standard feature for new home construction in San Diego County as well. The energy demand of new and renovated buildings should also be minimized by requiring that cost-effective green building design principles be utilized. The affect of incorporating green building principles is dramatic. California's Attorney General Jerry Brown has specifically recommended that San Diego take these actions to more effectively address climate change.[188]

In it ongoing energy efficiency proceeding, the CPUC has issued a September 17, 2007 draft decision with three initiatives described as "essential": 1) all new residential construction in California will be zero net energy by 2020, 2) all new commercial construction in California will be zero net energy by 2030, and 3) the heating, ventilation, and air conditioning industry must be reshaped for maximum efficiency. The stated motivation for moving to zero net energy demand in new structures is the revolutionary impact of global warming on the global economy.[189]

22. Conclusions

1. Climate change is a critical problem and arguably the greatest single issue of our time. The *California Global Warming Solutions Act* of 2006, AB 32, mandates a 25 percent reduction in greenhouse gases by 2020 and an 80 percent reduction by 2050. Reaching these mandates will require a more rapid transition to renewable energy sources for power generation than is currently contemplated.

2. Domestic natural gas currently used in the San Diego region will be displaced by imported liquefied natural gas in 2009. Liquefied natural gas carries an additional 25 percent "lifecycle" greenhouse gas burden relative to domestic natural gas. This displacement will nullify the greenhouse gas reductions projected by SDG&E over the next decade. Accelerated deployment of energy efficiency measures and renewable energy technology would mean considerably less dependence on volatile natural gas prices and liquefied natural gas imports.

3. The San Diego region is projected to have approximately 4,600 MW of PV potential on commercial buildings, parking structures, and parking lots in 2010, as well as 2,800 MW

of technical potential on residential structures. The 2010 technical potential for PV is in the range of 7,400 MW. A major advantage of commercial and residential PV is the relative lack of siting controversies. Also, PV equipped with adequate (2- to 3-hour) battery storage would be a dependable energy resource during peak demand periods. 2,040 MW of PV capacity, equipped with sufficient battery support to reliably provide power at or near capacity during the 3 to 6 pm peak on hot summer days, would meet more than half of the San Diego area's peak power needs under most conditions in 2020.

4. A $1.5 billion PV incentive program would be sufficient to incentivize the construction of 2,040 MW of distributed PV in the San Diego area by 2020. The incentive program would be similar to the structure of SB1 and the California Solar Initiative, where an incentive pool of $3.35 billion is expected to add 3,000 MW of PV in California by 2017. A goal of SB1 and CSI is to reduce the cost of PV to the point where PV is cost-competitive with conventional natural gas-fired generation without incentives by 2016.

5. The expansion of rooftop commercial and residential PV systems and CHP projects is currently limited by: 1) the inability to sell excess power to SDG&E, and 2) the relatively low commercial electricity rates during peak demand periods that do not reflect the real value of the electricity.

6. The *Energy Action Plan* calls for a 20 percent reduction in energy consumption to be achieved in government and commercial buildings by 2015 compared to a 2003 baseline. The San Diego region's annual energy consumption over the last few years has been approximately 20,000 GWh. Setting a real 20 percent reduction in regional energy demand compared to the 2003 baseline year as the regional energy efficiency target would mean an absolute decline in energy demand of approximately 4,000 GWh, leaving a net total energy demand in 2020 of 16,000 GWh.

7. SDG&E peak demand in 2007 was 4,636 MW. Approximately 1,500 MW of this peak load was associated with residential and commercial building cooling systems. Yet little effort or money is currently being invested in reducing the demand of these cooling systems through utility energy efficiency incentive programs.

8. SDG&E will complete the installation of smart meters at all customer locations by 2011. SDG&E projects that these smart meters will reduce peak demand by 5 percent. Smart meters with thermostat control capability were demonstrated to reduce peak load by 27 percent during a three-year California test. The advent of smart meters also offers the potential to sequentially cycle a portion of the cooling systems drawing power from the grid. The duration of the cycling would be brief enough to avoid discomfort, yet would keep hundreds of MW of cooling system load off the power grid during periods of very high demand.

9. Central air conditioning units are the predominant residential cooling system. State-of-the-art central air conditioning units use as little as one-half the power of the "average" central air conditioning unit in the San Diego area. There is a similar gap in the energy efficiency of the typical commercial building cooling system in the San Diego area and

its potential performance with a cost-effective upgrade to variable speed motors and associated controls.

10. Lighting is an area where energy efficiency measures can have a dramatic impact. Compact fluorescent bulbs reduce energy demand by 75 percent relative to a standard incandescent bulb. Currently 10 to 20 percent of bulbs are compact fluorescent bulbs. New light emitting diode lighting technologies can also reduce lighting related demand even further.

11. Refrigeration has been a modest energy efficiency success story. The average energy efficiency of refrigerators in the San Diego area improved by 22 percent between 2000 and 2005. Federal "energy star" efficiency standards for refrigerators have been a factor. Consumer interest in energy efficiency has also been a factor in refrigerator purchasing decisions, supported by limited rebates offered by SDG&E.

12. Upgrading existing buildings to current Title 24 structural weatherization standards or beyond is cost-effective. The *Energy Action Plan* calls for all existing state buildings to be upgraded to meet rigorous "LEED" green building standards by 2015, and establishes the same goal for commercial buildings. SDG&E currently offers free home weatherization and energy efficient appliance replacement services to low-income customers via its "direct assistance" program. Expanding this program to include all cost-effective energy efficiency upgrades regardless of consumer income level is necessary to fully realize regional energy efficiency opportunities.

13. Rapid expansion of CHP is a priority goal in the *Energy Action Plan* and RES 2030. The *Energy Action Plan* prioritizes CHP over large central power plants. There is currently less than 400 MW of CHP capacity in the San Diego area. 700 MW of CHP must be added to meet the RES 2030 target of 1,100 MW of CHP capacity by 2020.

14. There will not be a need for additional utility-scale base load generation, beyond the 542 MW Palomar Energy and 561 MW Otay Mesa combined-cycle projects, if the deployment of CHP meets *San Diego Smart Energy 2020* targets. If *San Diego Smart Energy 2020* milestones and targets are met, there will also be no need to add additional peaking gas turbine capacity.

23. Recommendations

23.1 Greenhouse Gas Reduction

1. San Diego should reduce its greenhouse gas emissions from power generation at the maximum rate that is cost-effectively achievable. Implement a strategic energy program targeting a 50 percent reduction in greenhouse gas emissions by 2020. This target will put San Diego on par with California's two largest cities, San Francisco and Los Angeles, which have committed to 51 percent renewable energy by 2017 and 35 percent renewable energy by 2020, respectively. The 50 percent reduction in greenhouse gases will be achieved at a cost that maintains electricity rates at or below current utility rates.

2. Decouple SDG&E profit from traditional power plant and transmission line ratebase revenue streams. Couple profit to achieving: a) greenhouse gas reduction benchmarks, and b) *Energy Action Plan* loading order.

23.2 Energy Efficiency

1. Achieve an absolute 20 percent reduction in energy consumption relative to a 2003 baseline, from 20,000 GWh to 16,000 GWh.

2. Greatly expand the number and pace of energy efficiency retrofits of all non-Title 24 residential buildings and all commercial buildings in the San Diego area. Retrofits in warm and hot areas of SDG&E service territory are first priority, including Borrego Springs, El Cajon, La Mesa, Lemon Grove, Santee, Lakeside, Ramona, Poway, and Escondido.

3. The Center for Sustainable Energy, or an equivalent third party entity, should conduct the energy efficiency audit program. Expand staff as necessary to audit 10 percent of non-Title 24 residential buildings and 10 percent of commercial buildings without LEED certification per year during the 2008 through 2017 period.

4. Weatherize 10 percent of non-Title 24 residential buildings to the Title 24 standard and 10 percent of commercial buildings without LEED certification to the LEED-EB standard per year in the San Diego area beginning in 2008. Include all residential and commercial structures with a weatherization energy savings payback of ten years or less in the program. Weatherization cost should be borne by the utility or the CCA (whichever structure is in place).

23.3 Peak Demand Reduction

1. Achieve an absolute 25 percent reduction in peak demand relative to a 2006 baseline, from 4,636 MW to 3,500 MW. Twenty percent of this demand reduction would result from energy efficiency upgrades. Five percent of this demand reduction would result from use of smart meter technology and real-time dynamic pricing.

2. Maximize the demand response potential of smart meters combined with automatic thermostat controls to the degree technically feasible.

3. Establish a minimum target of 85 MW per year absolute reduction in peak demand, for a total of 1,100 MW peak demand reduction by 2020, with an emphasis on cost-effective central air conditioner and central plant upgrades. Combine cooling system upgrades, lighting retrofits, and weatherization projects to the degree possible to achieve maximum demand reduction.

23.4 Renewable Energy

1. Establish $1.5 billion capital incentive budget to add 2,040 MW of PV by 2020. Equip the PV systems with adequate battery storage to allow operation as peaking power units during summertime peak demand periods. Prioritize installation of commercial and residential PV over other forms of renewable energy for the following reasons: acceptable cost-effectiveness, minimal environmental impact, lowest potential to generate siting controversies, and production of energy when it is most needed.

2. SDG&E should establish a distributed generation rate structure that accurately reflects the peak demand benefits of renewable and CHP distributed generation. The rate structure should be modeled on PG&E’s A-6 tariff. This tariff has resulted in a high number of applications for commercial PV installations in PG&E service territory.

3. SDG&E should expand the policy of accepting all excess electricity generated from renewable energy and CHP distributed generation providers. SDG&E established the precedent for this policy with the October 2006 contract signed with Children’s Hospital of San Diego to accept excess electricity from Children’s 3.5 MW CHP plant.

4. Construct one 5 MW concentrating PV renewable energy park in San Diego County by 2010 to demonstrate such a unit can reliability serve as peaking capacity on hottest days.

5. Consider incorporating lower-cost renewable energy, specifically East County wind power, if candidate sites can be identified with acceptably low environmental and social impacts.

23.5 Combined Heat and Power

1. Add 700 MW of CHP capacity by 2020. CHP has the lowest GHG emissions of any natural gas-fired generation option. This objective is consistent with AB 1613 target of adding 5,000 MW of CHP in California by 2015. An additional 700 MW of CHP capacity in San Diego County would displace the need for a new baseload power plant in the region (beyond the 561 MW Otay Mesa project that is currently under construction).

23.6 Transmission and Distribution

1. Renovate the SDG&E 12 kV distribution system. Utilize smart grid technological innovations to improve the performance of the distribution system, to reduce congestion costs and enhance the integration of PV and CHP distributed generation sources.

2. Reinforce the existing north-south high voltage transmission corridor capacity (Path 44) to cost-effectively increase emergency import-export capacity from 2,500 MW to 2,850 MW. Increase the capacity of the east-west corridor (Southwest Powerlink) by upgrading transformers to increase rating from 1,900 MW to 2,100 MW of flow on a continuous basis.

23.7 New Construction

1. Require all new residential and commercial construction to be net zero energy demand. This means these structures incorporate state-of-the-art energy efficiency measures and are equipped with sufficient PV capacity to address the estimated annual energy demand of the structure.

24. Glossary

Term	Symbol	Definition
Advanced Metering Infrastructure	AMI	SDG&E $572 million project to install electronic electric and natural gas meters at all customer locations by 2011.
Baseload	--	The minimum amount of power required at most/all times in the utility service territory. In SDG&E territory the baseload power requirement is in the range of 1,500 to 2,000 megawatts.
Baseload power plant	--	A power plant that operates on a continuous basis at or near its output capacity.
California Energy Commission	CEC	California Energy Commission
California Independent System Operator	CAISO	California Independent System Operator
California Public Utilities Commission	CPUC	California Public Utilities Commission
Combined heat and power	CHP	Small natural gas-fired power plants less than 20 MW capacity that use hot exhaust gas from the combustion process to make steam for use in heating or cooling systems.
Community Choice Aggregation	CCA	Legal option available to California cities and counties to become electric power purchasers and generators independent of an investor-owned utility.
Demand response	DR	Actions that reduce electric power consumption during periods of peak demand.
Distributed generation	DG	Electric power that is generated at the point of use. This can be renewable power, such as rooftop solar panels, or small natural gas-fired combined heat and power plants serving businesses, universities, hospitals, and government facilities.
Fossil fuel	--	Natural gas, oil, and coal.
Gigawatt	GW	One million kilowatts, or one thousand megawatts. One gigawatt equals the electricity demand of ten million 100-watt incandescent light bulbs.
Gigawatt-hour	GWh	An electricity demand of one million kilowatts for one hour or one thousand megawatts for one hour.
Greenhouse gases	GHG	Gases that trap heat in the atmosphere and lead to an increase in ambient temperature. Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are prominent greenhouse gases.
Kilowatt	kW	Unit of measure of electrical output. One kilowatt equals the electricity demand of ten 100 watt incandescent light bulbs.

Kilowatt-hour	kWh	One kilowatt of usage for one hour. This is the approximate average continuous electricity demand of a typical single family home.
Imperial Irrigation District	IID	Public utility that serves Imperial County.
Investor-owned utility	IOU	Investor-owned utilities are private power monopolies that are regulated by the California Public Utilities Commission. There are three investor-owned utilities in California: Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.
Lifecycle cost	--	Estimated levelized cost of a power generation technology over a 20-year period.
Long-Term Procurement Plan	LTPP	SDG&E's 2007-2016 strategic resource planning document submitted to the CPUC for approval in December 2006.
Los Angeles Department of Water & Power	LADWP	Public utility that serves the City of Los Angeles.
Megawatt	MW	One thousand kilowatts. One megawatt equals the electricity demand of ten thousand 100-watt light bulbs.
Pacific Gas & Electric	PG&E	Investor-owned utility that serves northern and central California.
Peak load		Peak load is the maximum electricity demand experienced during the year. Peak load occurs during hot summer afternoons when air conditioners are running at maximum rates.
Peaking power plant		A power plant that is used only during periods of peak electricity demand.
Photovoltaic	PV	Process of converting light energy into electric power.
Public utility	---	A non-profit electric utility that is a component of the public services provided by a municipal, county, or regional government.
San Diego Regional Energy Strategy 2030	RES 2030	Strategic regional energy plan adopted by SANDAG Board of Directors in July 2003.
San Diego Association of Governments	SANDAG	Regional planning agency representing all incorporated cities in San Diego as well as county government.
San Diego Gas & Electric	SDG&E	Investor-owned utility that serves San Diego County and the extreme southwestern tip of Orange County.
Southern California Edision	SCE	Investor-owned utility that serves part of central California and all of southern California with the exception of San Diego and Imperial Counties.
Sunrise Powerlink	SPL	SDG&E's proposed 500 kV, 1,000 MW transmission line.
The Utility Ratepayers Network	TURN	Utility consumer's non-profit advocacy group based in San Francisco.
Utility Consumer's Action Network	UCAN	Utility consumer non-profit advocacy group in San Diego.

[1] CPUC A.05-12-014, SDG&E Sunrise Powerlink Transmission Project Purpose and Need, December 14, 2005, p. I-13.
[2] CPUC A.05-12-014, SDG&E Sunrise Powerlink application for Certification of Public Convenience and Necessity, Vol. II, August 4, 2007, p. III-9. "*In order to achieve a 20% renewable generation mix by 2010 based* on a 2009 forecast bundled customer retail sales benchmark of 17,418 GWh, SDG&E must obtain a total of approximately 3,484 GWh of renewable energy."
[3] CPUC, *Progress of the California Renewable Portfolio Standard as Required by the Supplemental Report of the 2006 Budget Act – Report to the Legislature*, April 2007, p. 7, Table 2, footnote 6. "Contracted and short-listed RPS capacity (MW) associated with the Sunrise Powerlink could potentially be carried over the (existing) Southwest Powerlink.
[4] CPUC A.05-12-014, SDG&E Sunrise Powerlink application for Certification of Public Convenience and Necessity, Vol. II, August 4, 2007, p. IV-46. "*So, while it is reasonable to expect that the Commission's 2010 renewable resource goals could be physically achieved even if the Sunrise Powerlink were not built, . .*"
[5] SDREO PowerPoint on CSI program, presented to SANDAG EWG, March 17, 2007.
[6] http://www.gosolarcalifornia.ca.gov/csi/faqs.html
[7] K. Johnson - CPUC, *California Solar Energy Policy*, presentation given at 11th National Renewable Energy Marketing Conference, December 6, 2006.
[8] J. Clinton - CPUC, *Energy Action Plan – California Solar Initiative*, PowerPoint presentation, CPCU-CEC Joint Meeting, Sept. 18, 2006.
[9] http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF
[10] CPUC Decision 06-02-032, *Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning - Opinion On Procurement Incentives Framework*, Rulemaking 04-04-003, February 16, 2006.
[11] California Environmental Protection Agency, *Climate Action Team Report to Governor Schwarzenegger and the California Legislature*, March 2006, p. iv.
[12] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Volume I, 2007-2016 Long-Term Procurement Plan, p. 183.
[13] Voice of San Diego, *SDG&E Lags on Energy Efficiency Goals*, February 15, 2007.
[14] CPUC D.0709043, Published Final Decision – *Interim Opinion on Phase I Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs*, September 20, 2007.
[15] For example, SDG&E forecasts a total electricity demand in SDG&E service territory of 24,679 GWh in 2016, while forecasting retail sales of 19,076 GWh for that same year. The difference, 5,603 GWh, is electricity purchased by direct access customers.
[16] SDG&E and Southern California Gas Company are owned by Sempra Energy. Sempra, SDG&E, and Southern California Gas Company lobby as one entity in Sacramento.
[17] California Energy Markets, *Committee Holds 33 Percent-by-2020 RPS Bill*, April 27, 2007, p. 12. Sempra Energy lobbyist Cindy Howell said the bill (AB 94) was "premature" given that the 20 percent standard became law last year. Sempra also opposed AB 1470, the Solar Hot Water and Efficiency Act of 2007. Sempra lobbyist Cindy Howell noted that the $2.1 billion California Solar Initiative had budgeted funds for solar hot-water heaters and cautioned against a "double collection." (p. 14).
[18] Electricity is provided to Long Beach customers by SCE. However, natural gas is provided to Long Beach customers by Long Beach Energy, a public non-profit utility.
[19] E-mail correspondence from R. Freehling, Local Power, to B. Powers, May 15, 2007.
[20] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, draft staff report, CEC-200-2007-011-SD, June 2007, p. 7.
[21] E-mail correspondence from R. Freehling, Local Power, to B. Powers, May 15, 2007.
[22] Ibid.
[23] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, draft staff report, CEC-200-2007-011-SD, June 2007, p. 7.
[24] B. Powers telephone conversation with M. Johnson, Gaia Power Technologies, August 31, 2007. Suggested retail price for Gaia Power Tower for 11,000 watt PV system, with 50 kW-hr of storage, is $15,000. This price includes the inverter, storage, charge controller, and ability to grid tie. Gross cost for 11,000 watt PV system without battery storage is approximately $90,000 installed, including inverter (pro-rated from example in Table 8). The approximate retail equipment cost of inverters for this grid-tie only 11,000 watt PV system is $9,000 (source: Xantrex customer

support, Sept. 4, 2007. Three Xantrex GT4.0 inverters required for 11,000 watt system, retail price $3,130 per inverter). The net increase in gross system cost to adapt the PV system for peaking power service by substituting the grid-tie only inverter(s) with a Gaia Power Tower is less than 10 percent, from $90,000 to $96,000.

[25] California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies, draft staff report, CEC-200-2007-011-SD, June 2007, p. 7.

[26] Joseph Tomain, Richard Cudahay, *Energy Law in a Nutshell*, Thomson-West, 2004, Chapter 4, Energy Decisionmaking, pp. 130-143.

[27] Don Wood e-mail to B. Powers describing history of California IOU ratebasing policy and energy conservation efforts, June 8, 2007.

[28] 1981 CPUC Decision 93892.

[29] CPUC D.0709043, Published Final Decision – *Interim Opinion on Phase I Issues: Shareholder Risk/Reward Incentive Mechanism for Achieving Energy Efficiency Goals*, September 20, 2007.

[30] Sempra Energy press release, May 2, 2007: http://www.shareholder.com/sre/ReleaseDetail.cfm?ReleaseID=240324

[31] Sempra Energy, U.S. Department of Energy Presidential Permit No. PP-235-02 for Termoeléctrica U.S. LLC, April 18, 2001.

[32] CFE, *Generation and Transmission Expansion Plan – Baja California System, 2003-2007*, presented at CAISO Southwest Transmission Expansion Plan meeting, San Diego, March 13, 2003. http://www1.caiso.com/docs/2003/03/24/2003032411203218418.pdf

[33] CPUC proceeding A. 06-08-010, SDG&E Sunrise Powerlink application, Michael Shames/UCAN rebuttal testimony, June 15, 2007.

[34] Ibid.

[35] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Volume I, 2007-2016 Long-Term Procurement Plan, p. 207.

[36] California Energy Commission, *Natural Gas Market Assessment – Preliminary Results*, staff draft report, in support of CEC 2007 Integrated Energy Policy Report, CEC-200-2007-009-SD, May 2007, p. 3.

[37] CPUC Decision 04-09-022, *Rulemaking 04-01-025 to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California*, Phase I, Sept. 2, 2004. Findings of Fact (p. 89): 38. There is potential California customer access to LNG supplies through Otay Mesa, Ehrenberg/Blythe, Oxnard and Long Beach. 39. Designating Otay Mesa as a common receipt point for both the SoCalGas and SDG&E systems will send a signal to potential LNG suppliers that the gas they provide will have access to the utilities' systems.

[38] P. Jaramillo, Carnegie-Mellon University, *Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, published online July 25, 2007, and "Supporting Information" document. All CO_2 emission factors listed in this footnote are from the "Supporting Information" document. Assume the LNG is shipped from BP liquefaction plant in Tangguh, Indonesia, 7,500-mile tanker roundtrip to Sempra LNG regasification terminal in Baja California. The raw gas feeding the Tangguh liquefaction plant contains 10 percent CO_2 which will be vented to atmosphere at the plant (source: BP Indonesia webpage http://www.bp.com/sectiongenericarticle.do?categoryId=9004748&contentId=7008786). This is equivalent to a CO2 emission rate of 12 lbs CO_2 per MMBtu, per the Carnegie-Mellon estimate of 120 lbs CO_2 per MMBtu of natural gas combusted. Assume average CO_2 generation from liquefaction (14 lb CO_2 per MMBtu without considering CO_2 content in raw gas). 7,500 miles is the same distance as Oman to the Everett, Massachusetts LNG terminal route cited in report, which generates 8 lb CO_2 per MMBtu in transport CO_2 emissions. Assume CO_2 generation from LNG regasification and storage is low due to use of seawater heating to regasify the LNG (1 lb CO_2 per MMBtu). Domestic natural gas emits a maximum of 140 lb CO_2 per MMBtu. Total additional CO_2 associated with LNG from Tangguh, Indonesia is 35 lb CO_2 per MMBtu. Incremental lifecycle CO_2 emissions associated with LNG imported from Tangguh are 35 lb $CO_2 \div 140$ lb $CO_2 = 0.25$, or a 25 percent increase in lifecycle CO_2 emissions.

[39] The California Energy Commission indicates that LNG from Sempra's Baja California import terminal will displace domestic natural gas from the Southwest (source: CEC Staff Draft Report, *Natural Gas Market Assessment Preliminary Results*, in support of the *2007 Integrated Energy Policy Report*, CEC-200-2007-009-SD, May 2007, p. 2. Finding: "The amount of gas produced in the Southwest, which enters California at Blythe, gradually decreases during the forecast period as natural gas imported from Mexico (Costa Azul Facility) displaces domestic production from the Southwest."). Most domestic natural gas sources serving Southern California from the Southwest, specifically the Permian Basin of West Texas and the San Juan Basin of New Mexico, have low inherent raw gas CO_2 concentrations, on the order of 1 percent CO_2 or less. The sources of natural gas used in California are shown in Attachment C, Figure 4. A number of gas fields in the Permian Basin of West Texas have elevated CO_2 concentrations. However, this CO_2 is removed at the gas processing plant and used in CO_2 enhanced oil recovery

operations. This CO_2 is sequestered permanently in the oil formation when it displaces the oil or is recycled for further use in the enhanced oil recovery operation (source: e-mail from Mark Holtz, petroleum geologist, Bureau of Economic Geology, University of Texas – Austin, to Bill Powers, September 26, 2007).

[40] New York Times, *A New Push to Regulate Power Costs*, September 4, 2007.

[41] CPUC R.06-04-09, Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies. *Documentation for Emission Default Factors in Joint Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol R.06-04-009 and Docket 07-OIIP-01 - Process Used to Determine Default Out-of-State Emissions factors*, June 20, 2007, p. 4.

[42] Excerpt from OLR Research Report, State of Connecticut, *Decoupling Utility Sales and Earnings*, 2005-R-0702, October 3, 2005.

[43] California Public Utilities Commission Rulemaking 06-04-10, *Rulemaking to Examine the Commission's post-2005 Energy Efficiency Policies, Programs, Evaluation, Measurement and Verification*, and Related Issues, Proposed Decision, August 9, 2007.

[44] CPUC A.05-12-014, SDG&E Sunrise Powerlink application for Certification of Public Convenience and Necessity, Vol. II, August 4, 2007, p. II-48 thru p. II-50.

[45] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Exhibits, 2007-2016 Long-Term Procurement Plan, p. 60 (of .pdf).

[46] Although San Onofre nuclear plant is physically located in San Diego County, SDG&E classifies energy from San Onofre as imported for resource planning purposes.

[47] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Volume II, 2007-2016 Long-Term Procurement Plan, p. 4.

[48] See Attachment C, Figure 1.

[49] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Volume I, 2007-2016 Long-Term Procurement Plan, p. 193-194.

[50] "Capacity factor" is the ratio of the actual power produced over time to the theoretical potential power output of a source.

[51] SDG&E 2006 statistics on residential customer demand, provided by SDREO, May 16, 2007.

[52] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region*, August 2005. www.renewablesg.org.

[53] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Exhibits, 2007-2016 Long-Term Procurement Plan, p. 193.

[54] Ibid.

[55] US News, *Southern California sets power records*, September 4, 2007.

[56] SDG&E 1999-2006 peak demand trend chart, provided by Center for Sustainable Energy, June 10, 2007.

[57] SDG&E 2007-2016 Long-Term Procurement Plan, December 11, 2006, Exhibits, p. 193.

[58] Moody's Economy.com. http://www.economy.com

[59] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Exhibits, 2007-2016 Long-Term Procurement Plan, December 11, 2006, pp. 193-194.

[60] U.S. Census Bureau, San Diego County QuickFacts.

[61] U.S. Census Bureau, Population Division, Interim State Population Projections, 2005 - Table 3:Estimate of Population Change for Counties of California and County Rankings: July 1, 2005 to July 1, 2006.

[62] U.S. Census Bureau, San Diego County QuickFacts.

[63] U.S. Census Bureau, Population Division, Interim State Population Projections, 2005 - Table 7: Interim Projections: Change in Total Population for Regions, Divisions, and States: 2000 to 2030.

[64] Economy.com. Historic population statistics through 2nd Q 2006 and forecast through 2035.

[65] San Diego Union Tribune, *July 2007 home prices*, Section D, p. 2, August 19, 2007. The sale price of resale (existing) single family detached homes in San Diego County is currently $550,000 and has averaged $550,000 to $600,000 since early 2005 per Dataquick Information Services.

[66] San Diego Union Tribune, *Job creation in county takes shape of hourglass*, September 2, 2007, p. F1.

[67] San Diego Regional Energy Office, *Strategy 2030 – The San Diego Regional Energy Strategy*, prepared for San Diego Area Governments, May 2003. http://www.energycenter.org/uploads/Regional_Energy_Strategy_Final_07_16_03.pdf

[68] Report on the Energy Working Group Assessment Process for the Sunrise Powerlink Transmission Project, November 2006, Attachment 1 to Regional Planning Committee Recommendation on the SDG&E Sunrise

Powerlink Transmission Project, agenda item No. 06-11-13, SANDAG Board of Directors meeting, November 17, 2006.
[69] SANDAG Energy Working Group meeting agenda, SDG&E 2006 Long-Term Resource Plan (LTRP), January 25, 2007, p. 36. http://www.sandag.cog.ca.us/uploads/meetingid/meetingid_1572_6487.pdf
[70] R. Caputo, B. Butler, Solar 2007: *The Use of "Energy Parks" to Balance Renewable Energy in the San Diego Region*, American Solar Energy Society, annual conference, Cleveland, July 2007.
[71] Jim Bell, *Creating a Sustainable Economy and Future on Our Planet - San Diego/Tijuana Region Case Study*, 2nd edition, March 2007.
[72] Local Power, *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*, prepared for Environmental Health Coalition, February 15, 2007.
[73] San Diego Regional Renewable Energy Study Group, www.renewablesg.org, August 2005.
[74] Jim Trauth, Envision Solar, estimate of solar parking lot potential in San Diego County, e-mail, June 13, 2007.
[75] The 25 percent estimate is expected to be quite conservative. A detailed statistical assessment would be necessary to accurately quantify the PV potential of the resource. Generally only small- or moderately-sized parking lots and parking structures that are immediately east of tall buildings would be excluded as candidates for PV installations. PV installations in parking lots immediately west of tall buildings could be oriented to maximize output during the afternoon summertime peak demand period. This would minimize or eliminate the shading effect of any building to the east.
[76] Executive Order S-20-04 by the Governor of the State of California, July 27, 2004. http://www.dot.ca.gov/hq/energy/ExecOrderS-20-04.htm
[77] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region*, August 2005. www.renewablesg.org.
[78] E-mail from Tom Blair, City of San Diego, to B. Powers, June 27, 2007.
[79] http://www.sdge.com/construction/sustainable.shtml
[80] SDG&E Sustainable Communities Program Case Study, TKG Consulting Engineers Inc. Office Building, 2004.
[81] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Exhibits, 2007-2016 Long-Term Procurement Plan, Exhibits, December 11, 2006, pp. 193-194 (of .pdf).
[82] CPUC Proceeding R.06-02-013, San Diego Gas & Electric (U 902-E), Volume I, 2007-2016 Long-Term Procurement Plan, p. 184.
[83] California Energy Circuit, *Utilities Best Efficiency Targets, are Pressured to Think Bigger*, May 11, 2007, p. 7.
[84] Itron, California Energy Efficiency Potential Study, May 24, 2006, p. ES-8, Table ES-3. Statewide technically feasible energy efficiency reductions in existing buildings combined with emerging energy efficiency technologies estimated at 58,000 GWh. Statewide economic energy efficiency reductions in existing buildings combined with emerging energy efficiency technologies estimated at 48,000 GWh.
[85] Xenergy, Inc., *California's Secret Energy Surplus – The Potential for Energy Efficiency*, Sept. 23, 2002, p. A-6.
[86] See SDG&E 2007-2016 Long-Term Procurement Plan, Volume I, December 11, 2006, p. 183, reference to 2006 Itron report.
[87] CPUC Decision 07-04-043, approval of SDG&E AMI program, April 12, 2007.
[88] SEER is relative measure of energy efficiency. A SEER 20 air conditioning unit uses one-half the energy required by a SEER 10 unit to produce the same amount of cooling.
[89]S. Okura, M. Brost, RLW Analytics, Inc., R. Rubin, SDG&E, *What Types of Appliances and Lighting Are Being Used in California Residences?*, 2005.
[90] [(21 – 10)/21] – [(13 – 10/13)] = 0.52 – 0.23 = 0.29 (29 percent)
[91] Itron, California Energy Efficiency Potential Study, May 24, 2006, Chapter 11 - Emerging Technology Energy Efficiency Potential, p. 11-5 and p. 11-6.
[92] Platts Purchasing Advisor, *HVAC: Centrifugal Chillers*, 2004.
[93] The term "kW per ton of cooling" is a measure of the electric energy necessary to operate a commercial or institutional chiller plant.
[94] One ton of cooling load is the amount of heat absorbed to melt one ton of ice in one day, which is equivalent to 12,000 Btu per hour.
[95] B. Erpelding, P.E., San Diego Regional Energy Office, *Ultraefficient All-Variable Speed Chilled-Water Plants – Improving the energy efficiency of chilled-water plants through the utilization of variable speed and the optimization of entire systems*, HPAC Engineering, March 2006, pp. 35-43

[96] B. Erpelding, P.E., San Diego Regional Energy Office, *Ultraefficient All-Variable Speed Chilled-Water Plants – Improving the energy efficiency of chilled-water plants through the utilization of variable speed and the optimization of entire systems*, HPAC Engineering, March 2006, pp. 35-43.
[97] All "number of device" and efficiency/performance estimates by device type for SDG&E service territory from S. Okura, M. Brost, RLW Analytics, Inc., R. Rubin, SDG&E, *What Types of Appliances and Lighting Are Being Used in California Residences?*, 2005.
[98] There are 1.2 million residential meters in SDG&E territory. Approximately 52 to 53 percent use central air systems based on California-wide statistics. Approximately 86 percent of these systems include central air conditioning (versus packaged HVAC systems).
[99] SEER – Seasonal Energy Efficiency Ratio.
[100] Dynamic pricing – charging customer for value of electricity at time it is used or saved. Highest prices and savings occur during summertime peak demand.
[101] CFL – Compact Fluorescent Lighting.
[102] 931 kWh/year was California average in 2000, declining to 721 kWh/year in 2005. Decline was driven by increasingly stringent federal efficiency standards.
[103] Title 24: California weatherization building standards for new residential and commercial construction.
[104] Benchmark is retrofit of TKG building in Sorrento Valley. Assumption is residential retrofits can achieve same reductions as commercial retrofits.
[105] Ibid.
[106] U.S. Green Building Council, *LEED-EB: Leadership in Energy and Environmental Design for Existing Buildings*, brochure, 2005.
[107] S. Okura, M. Brost, RLW Analytics, Inc., R. Rubin, SDG&E, *What Types of Appliances and Lighting Are Being Used in California Residences?*, 2005.
[108] Carrier product bulletin for SEER 10 model 38TKB036-34 three-ton air conditioning unit, 2004, p. 24.
[109] San Diego Union Tribune, Carrier central air conditioner advertisement on p. A-17, September 9, 2007.
[110] (4.0 kWh × 1,000 hours) –[(4.0 kWh × 1,000 hours) (10/21)] = 2,100 kWh saved. SDG&E estimates a summertime energy charge, when air conditioning units would be running, at $0.15/kWh to $0.25/kWh (source: San Diego Union Tribune, SDG&E "Stay Cool. Save Green." energy conservation announcement, August 26, 2007, p. A-17). Assuming an average summertime energy charge of $0.20/kWh, this lower electricity consumption represents a $400 annual savings.
[111] Avalanche Mechanical (Carrier installer) quote to B. Powers for 3-ton SEER 21 central air conditioning and heating unit, September 4, 2007.
[112] (4 kWh × 1,000 hr) × [(10/13) – (10/21)] = 1,172 kWh. Energy savings from selecting 3-ton SEER 21 unit over SEER 13 unit for 1,000 hours of operation.
[113] SDG&E defines the summer peak period as May 1 to September 30, 11 am to 6 pm. This is 1,071 hours per year.
[114] SDG&E presentation, *SDG&E's Time-of-Use Electric Rate Structures & Net Energy Metering*, 2007. For commercial customers SDG&E is proposing a critical peak rate of $1.20/kWh for up to 126 hours per year.
[115] The Brattle Group estimates a 40 percent reduction in peak demand is achievable with smart meters and thermostat control. May 16, 2007 report.
[116] SDG&E 2006 customer statistics – all categories. SDG&E estimates approximately 1.2 million residential customers.
[117] S. Okura, M. Brost, RLW Analytics, Inc., R. Rubin, SDG&E, *What Types of Appliances and Lighting Are Being Used in California Residences?*, 2005. In 2005, 53% of California homes had some form of cooling system.
[118] *SDG&E Low Income Energy Efficiency Programs Annual Summary and Technical Appendix – 2005 Results*, May 2006.
[119] The United States Conference of Mayors, Best Practices Guide, 2007. See: www.usmayors.org
[120] This summary is excerpted from the following two documents: California Energy Markets, *Demand Response Situation in California*, April 24, 2007, and The Brattle Group, *The Power of Five Percent – How Dynamic Pricing Can Save $35 Billion in Electricity Costs*, discussion paper, May 16, 2007.
[121]The Brattle Group, *The Power of Five Percent – How Dynamic Pricing Can Save $35 Billion in Electricity Costs*, discussion paper, May 16, 2007.
[122] CPUC A.05-12-014, SDG&E Sunrise Powerlink - Application for Public Convenience and Necessity, Vol. II, August 4, 2006, p. IV-12. AMI impacts are in support of the 4%/5% DR goals – 5% reduction in 2016.
[123]Ibid, p. II-32 and p. VI-26.

[124] June 19, 2007 and September 4, 2007 e-mail from J. Supp, California Solar Initiative program manager, Center for Sustainable Energy California, San Diego, to B. Powers.
[125] San Diego Union Tribune, SDG&E "Stay Cool. Save Green" energy conservation announcement, August 26, 2007, p. A-17. Residential energy charge varies from $0.15/kWh (low consumption rate) to $0.25/kWh (high consumption rate).
[126] J.P. Ross – Vote Solar, *Rate Design – Key to a Self-Sufficient Solar Market*, PowerPoint presentation, 2006.
[127] CPUC R07-01-047, SDG&E Phase 2 General Rate Case, proposed AL-TOU rate for commercial solar systems.
[128] J. Shah, SunEdison, San Diego Solar Initiative financial plan - $1.5 billion incentives budget, Sept. 12, 2007.
[129] CPUC proceeding A. 06-08-010, SDG&E Sunrise Powerlink application, August 4, 2006, p. V-11. Estimated levelized cost of SPL is $174 million per year for 40 years. Total levelized cost is $174 million per year x 40 years = $6.96 billion.
[130] San Diego Union Tribune, *SDG&E could alter Powerlink plan*, September 7, 2007.
[131] PRNewswire, *Brattle Study Documents Significant Increases in Utility Construction Costs Not Yet Reflected in Current Forecasts of Retail Rate Increases*, September 6, 2007.
[132] News release, California ISO – Stage One Electrical Emergency Issued, August 29, 2007.
[133] J. Shah, SunEdison, June 27, 2007 e-mail to B. Powers.
[134] Thomas P. Kimbis, U.S. Department of Energy, *The President's Solar America Initiative – Technology Acceptance*, August 2, 2006, p. 3.
[135] RenewableEnergyAccess.com, *PV Costs to Decrease 40% by 2010*, May 23, 2007.
[136] Press release, Gaia Power Technologies Partners with Southern California Edison to Increase Efficiency of Residential Solar Power Systems, March 27, 2007. www.gaiapowertechnologies.com/CEC_partnership.html
[137] The current gross installed cost of a residential PV system is approximately $8 per watt (see Table 8). The approximate gross cost of an 11 kW system without battery storage is $90,000. The cost of the inverter(s) for this system is approximately $9,000. Gaia Power Technologies "manufacturer's suggested retail price" for an 11 kW, 50 kWh energy management/battery system, which includes an inverter, is $15,000. The addition of the energy management/battery system adds less than 10 percent to the gross cost of the PV system.
[138] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region*, August, 2005, p. 22. www.renewablesg.org.
[139] Jonathan Lesser et al – Bates White, *Design of an Economically Efficient Feed-in Tariff*, California Energy Commission Integrated Energy Policy Report Workshop on "Feed-In" Tariffs, May 21, 2007, p. 9.
[140] e-mail communication for D. Marcus to B. Powers, September 7, 2007.
[141] B. Powers telephone conversation with Bob Martin, San Diego City Schools point-of-contact for solar roofs program, June 15, 2007.
[142] CPUC proceeding A. 06-08-010, SDG&E Sunrise Powerlink application , B. Bulter PhD testimony, June 1, 2007.
[143] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region*, August 2005. www.renewablesg.org.
[144] B. Powers telephone conversation with Scott Canada, Arizona Public Service - APS, on performance of Amonix concentrating PV at APS solar test center in Tempe, Arizona, June 27, 2007.
[145] PRNewswire, PG&E adds utility-scale solar projects to its power mix, June 27, 2007.
[146] Ibid.
[147] R. Caputo, B. Butler, Solar 2007: *The Use of "Energy Parks" to Balance Renewable Energy in the San Diego Region*, American Solar Energy Society, annual conference, Cleveland, July 2007.
[148] CEC lifecycle power generation cost comparison study, June 12, 2007.
[149]As shown in Figure 8, there are four existing 69 kVcorridors in the eastern section of San Diego County. According to SDG&E direct testimony by Richard Sheaffer on April 14, 2006 in CPUC proceeding A.06-04-018 that the 69 kV rating of SDG&E's Escondido to Felicita 69 kV line will be increased to 137 MW using a standard steel reinforced conductor. "*Acceleration of the reconductoring of the Escondido to Felicita 69 kV line. . . The project would increase the rating of the 69 kV line from 97.5 MVA to 137 MVA using a single 1033 kCMIL aluminum conductor steel reinforced ("ACSR") conductor or equivalent.*" 137 MVA is equivalent to 137 MW. Assuming the MW capacity of a aluminum conductor composite reinforced ("ACCR") standard 69 kV line could be increased from 137 MW to at least 250 MW if it is reconductored with a high temperature, low sag line, the total capacity of the East County 69 kV grid would be increased to the range of 1,000 MW.

[150] CPUC A.05-12-014, Sunrise Powerlink, SDG&E application for Certification of Public Convenience and Necessity, SDG&E data response to Data Request Number 1, Submittal 3 of 3, November 17, 2006, p. 13. "*In July 2005, SDG&E installed three spans (total of approximately 910 ft.) of ACCR conductor on an existing 69 kV transmission line as part of this research project.*"
[151] SDG&E PowerPoint, *Transmission Constraints to Geothermal Resource Development*, CEC IEPR Committee Workshop, April 11, 2005, p 7.
[152] 3M aluminum conductor composite reinforced (ACCR) website, Benefits – Save Money, http://solutions.3m.com/wps/portal/3M/en_US/Energy-Advanced/Materials/Industry_Solutions/MMC/ACCR/Benefits/ROI
[153] San Diego Regional Renewable Energy Study Group, August 2005. www.renewablesg.org.
[154] San Diego Union Tribune, *Sempra to acquire wind farm co-rights*, June 30, 2007.
[155] R. Caputo, B. Butler, Solar 2007: *The Use of "Energy Parks" to Balance Renewable Energy in the San Diego Region*, American Solar Energy Society, annual conference, Cleveland, July 2007..
[156] The capacity factor of the regional wind resource is ~30 percent, while it is only ~20 percent for fixed rooftop PV. This means that for the same MW capacity the wind farm is producing about 50 percent more MW-hours of energy production over the course of a year than fixed rooftop PV.
[157] Press release, *Gaia Power Technologies Partners with Southern California Edison to Increase Efficiency of Residential Solar Power Systems*, March 27, 2007. www.gaiapowertechnologies.com/CEC_partnership.html
[158]Telephone conversation between John Supp of Center for Sustainable Energy and Bill Powers, September __, 2007. The inclusion of Gaia Power Towers within the CSI incentive program is imminent.
[159] New York Times, *Google and Utility to Test Hybrids That Sell Back Power*, June 19, 2007.
[160] AQMD Advisor, Update on Plug-in Hybrid Program, Vol. 14, No. 3, May 2007.
[161] The total remaining geothermal potential in the Salton Sea area is estimated at 1,300 to 1,900 MW. However, about half of this resource is under the Salton Sea, and it is not economical to develop the under water resource with current technology. The May 2007 Salton Sea Restoration Plan envisions converting this area into dry land for geothermal development by 2025.
[162] R. Caputo, B. Butler, Solar 2007: *The Use of "Energy Parks" to Balance Renewable Energy in the San Diego Region*, American Solar Energy Society, annual conference, Cleveland, July 2007.
[163] SDG&E, 2007-2016 LTPP, Vol. 1, December 11, 2006, p. 207. Assume combined cycle heat input is 7 MMBtu/MWh, simple cycle peaking turbina is 10 MMBtu/MWh.
[164] SDG&E 2007-2016 Long-Term Procurement Plan, December 11, 2006, p. 195.
[165] Energy Working Group Meeting Notice and Agenda, *Policy Subcommittee Recommendations for Energy Working Group (EWG) Legislative Efforts*, November 16, 2006, p. 18. http://www.sandag.cog.ca.us/uploads/meetingid/meetingid_1551_6114.pdf
[166] Excerpt from California Energy Circuit, *State Sees DG Providing 25% Peak Power*, May 11, 2007, p. 8.
[167] SANDAG SourcePoint, *Major Activity Centers in the San Diego Region*, May 2002, No. 2. Major private employers, 82 (> 500 employees); major city and county government centers, 93 (> 300 employees each); major military sites, 14 (> 3,000 employees each); major hospitals, 14 (> 200 beds); major shopping complexes, 14; large hotels, 30 (> 300 rooms); large universities and colleges, 15 (> 1,000 full time students).
[168] California Cogeneration Council, *Pre-Workshop Opening Comments of California Cogeneration Council*, June 4, 2004, CPUC R. 04-04-025, Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities. "*The 1978 Public Utilities Regulatory Policies Act (PURPA) sought to reduce the country's dependence on oil through the development of new resources for electric generation, including renewable resources (solar, wind, biomass, geothermal, and small hydro) and the more efficient use of oil and gas in cogeneration projects. PURPA's key reforms included a requirement that the utilities must purchase the power output of qualifying cogeneration and other small power production facilities (referred to as "qualifying facilities" or "QFs") – a key step designed to encourage the development of QFs by ensuring a buyer for QF power. PURPA also required the utilities to purchase QF power at the purchasing utility's avoided cost–that is, at the cost that the utilities would have incurred themselves to produce or purchase the same energy and capacity. This avoided cost standard ensured that the utilities could not use their sole buyer power to depress the price paid to QFs. In California, this Commission found that the utilities had erected barriers to QF development, including to the development of cogeneration projects. In response, the Commission took the further step of developing "standard offer" power purchase contracts, available to any QF, that governed the terms of QF power sales to the utilities. The standard offer contracts greatly reduced the barriers to QF entry, by providing QFs with access to reasonable power purchase agreements that did not require extensive negotiations with the utility. The standard offer contracts included fixed capacity payments over*

the term of the contract; these payments were based on the levelized cost of the utility's cheapest source of capacity at that time–a combustion turbine. Energy payments reflected the utility's operating costs that it avoided through its QF purchases (principally the costs of additional gas- or oil-fired thermal generation). Most of the state's cogeneration projects were developed and built between 1982 and 1990, under 20- to 30-year contracts which provided for the sale of excess electricity to the local utility. These long-term power purchase contracts enabled cogeneration plants to make firm commitments to supply power and steam to their host industrial and institutional facilities".

[169] SDG&E, *SDG&E's Time-of-Use Electric Rate Structures & Net Energy Metering*, PowerPoint, February 2007, p. 17. The critical peak price would apply for up to 18 events from 11 am to 6 pm (7 hours each).

[170] Assume gas turbine has a heat rate of 10,000 Btu/kWh and cost of natural gas is $7/MMBtu. Hourly fuel cost to produce 2,000 kW, assuming natural gas cost is $7/MMBtu: 2,000 kW x 10,000 Btu/kW x (1 x 10^{-6} MMBtu/Btu) x $7/MMBtu = $140 per hour fuel cost. Total fuel cost for 126 hours: $140/hr x 126 hours = $17,640.

[171] B. Powers telephone conversation with Chris Lyons, Solar Turbines. Approximate installed cost of 5,000 kW CHP plant is 1,500 per kW. If financed at 7% interest over 30 years, financing requirement is $600,000 per year.

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

[173] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, draft staff report, CEC-200-2007-011-SD, p. 56.

[174] Load flowing in this case means operating near peak capacity at night and on cloudy days and at low load or offline during the day when the PV systems are operating.

[175] San Diego Solar Initiative installed PV capacity with storage – 2,040 MW; CSI installed PV capacity without storage – 300 MW; installed CHP capacity – 1,050 MW. Total is 3,390 MW.

[176] CPUC Application No. 06-12-009, SDG&E gas and electric revenue requirement and rates, prepared testimony of Caroline A. Winn on behalf of SDG&E, December 2006, p. CCAW-4 and pp. 136-142. The first three paragraphs in this section are excerpts from this testimony.

[177] Ibid.

[178] SAIC, *San Diego Smart Grid Study Final Report*, prepared for Energy Policy Initiatives Center, October 2006, pp. 1-4.

[179] SDG&E SPL application No. A. 06-08-010, *UCAN Testimony on UCAN's Alternatives and Deficiencies of SDG&E and ISO Methodologies – REDACTED VERSION*, testimony of David Marcus on behalf of UCAN, June 1, 2007, pp. 13-17.

[180] Ibid, p. 6-10.

[181] Energy Working Group Meeting Notice and Agenda, *Policy Subcommittee Recommendations for Energy Working Group (EWG) Legislative Efforts*, November 16, 2006.
http://www.sandag.cog.ca.us/uploads/meetingid/meetingid_1551_6114.pdf

[182] CPUC D.0709043, Published Final Decision – *Interim Opinion on Phase I Issues: Shareholder Risk/Reward Incentive Mechanism for Achieving Energy Efficiency Goals*, September 25, 2007.

[183] Kellie Smith, AB 1064 analysis, prepared for Senate Energy, Utilities and Communications Committee, July 2, 2007.

[184] Energy Policy Initiatives Center, summary of 2007-2008 pending California energy legislation, July 2007.

[185] J. Shah, SunEdison LLC, F. Ramirez, Ice Energy, Richard Brent, Solar Turbines, et al, letter to chairman Steven Larsen, chairman of Maryland Public Service Commission and Karl Pfirrman, interim CEO of PJM, LLC requesting thorough study of specific renewable energy, demand management measures, and high efficiency distributed generation as alternative to proposed $1.8 billion transmission line, August 17, 2007.

[186] Ibid.

[187] Fresno Bee, *Let the sun shine: Lennar Homes plans to install solar energy systems on all its new houses*, August 22, 2007.

[188] Voice of San Diego, *AG: City's Global Warming Plan Not Tough Enough*, July 5, 2007.

[189] CPUC Commissioner Grueneich open letter on proposed decision in R.06-04-010 energy efficiency proceeding, *Interim Order on Issues Relating to Future Savings Goals and Program Planning for 2009-2011 Energy Efficiency and Beyond*, September 17, 2007.

Attachments

Attachment A: Proposed Route of Sunrise Powerlink through Anza Borrego State Park

SDG&E's preferred route for the proposed 500 kV Sunrise Powerlink transmission line will pass through the center of Anza Borrego State Park. The proposed route will follow the pathway of an existing 40-foot high, 69 kV transmission line that has been in operation since the 1920s. Anza Borrego State Park is home to the largest population in the United States of the federally-listed endangered Peninsular Bighorn Sheep. The 500 kV transmission towers will be much larger than the existing 69 kV transmission poles in the park and will potentially change the character of the wilderness landscape.

Figure A1. The numbered transmission route in the center of the map below is the preferred route proposed by SDG&E. It will pass through the park on a route that takes it along the Vallecitos Mountain Wilderness, Pinyon Ridge Wilderness, and Grapevine Mountain Wilderness.
[http://www.cpuc.ca.gov/environment/info/aspen/sunrise/sunrise.htm]

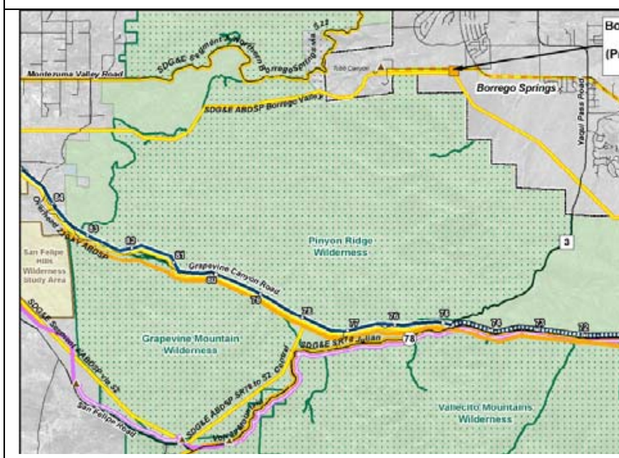


Figure A2. Anza-Borrego State Park is a World Heritage site and the largest state park in California. Two 40-foot high, 69 kV creosote pole transmission lines have been in operation in the area since the 1920s, predating the founding of the park in the 1930s.
[photo by Scot Martin]

Figure A3. Anza Borrego State Park is home to the largest U.S. population of endangered Peninsular Bighorn Sheep.

[photo by Scot Martin]

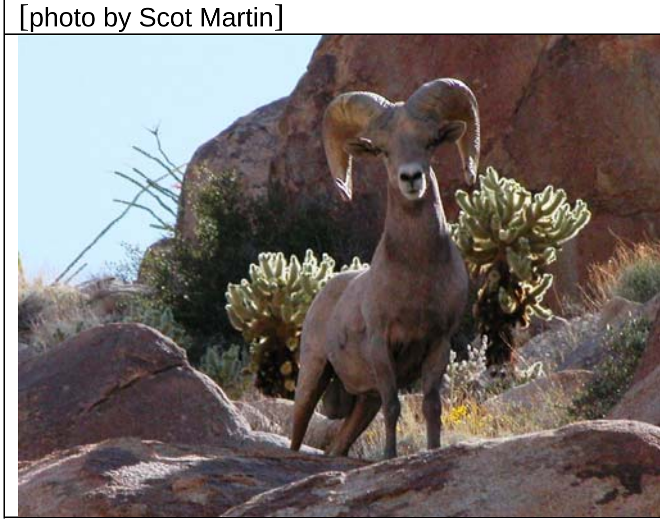
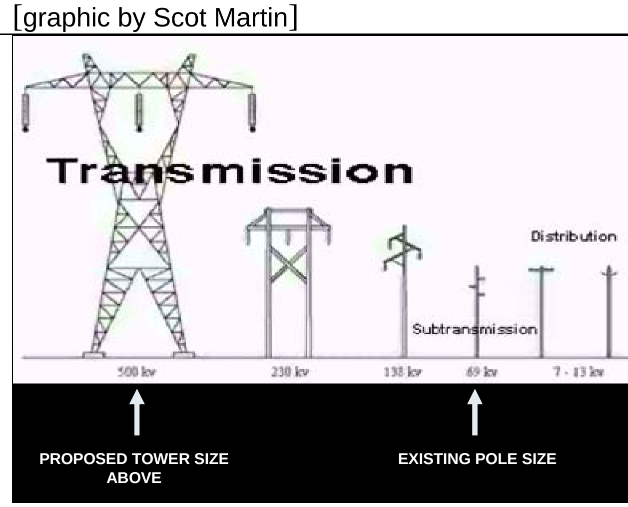


Figure A4. The 500 kV transmission towers proposed by SDG&E will be much larger than the existing 69 kV transmission poles in the park and will potentially change the character of the wilderness landscape.
[graphic by Scot Martin]



Attachment B: Regional Sempra Energy Infrastructure and Projected Sunrise Powerlink Route to Los Angeles

Figure B1. This concept map showing the Sunrise Powerlink ultimately interconnecting with the Los Angeles area transmission grid was submitted by SDG&E in its March 6, 2006 letter to the U.S. DOE requesting "national interest electric transmission corridor" status for the transmission line.

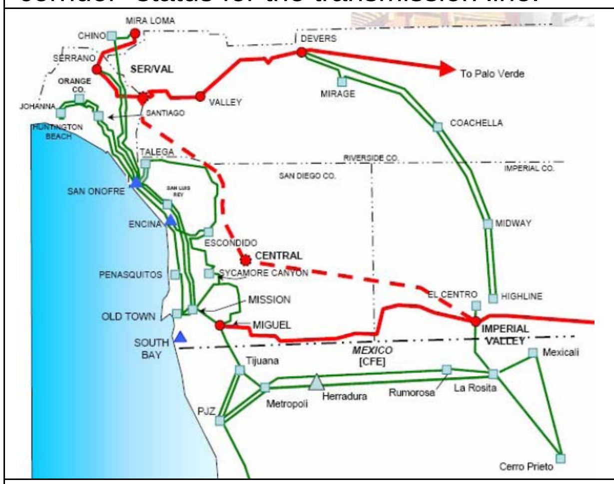
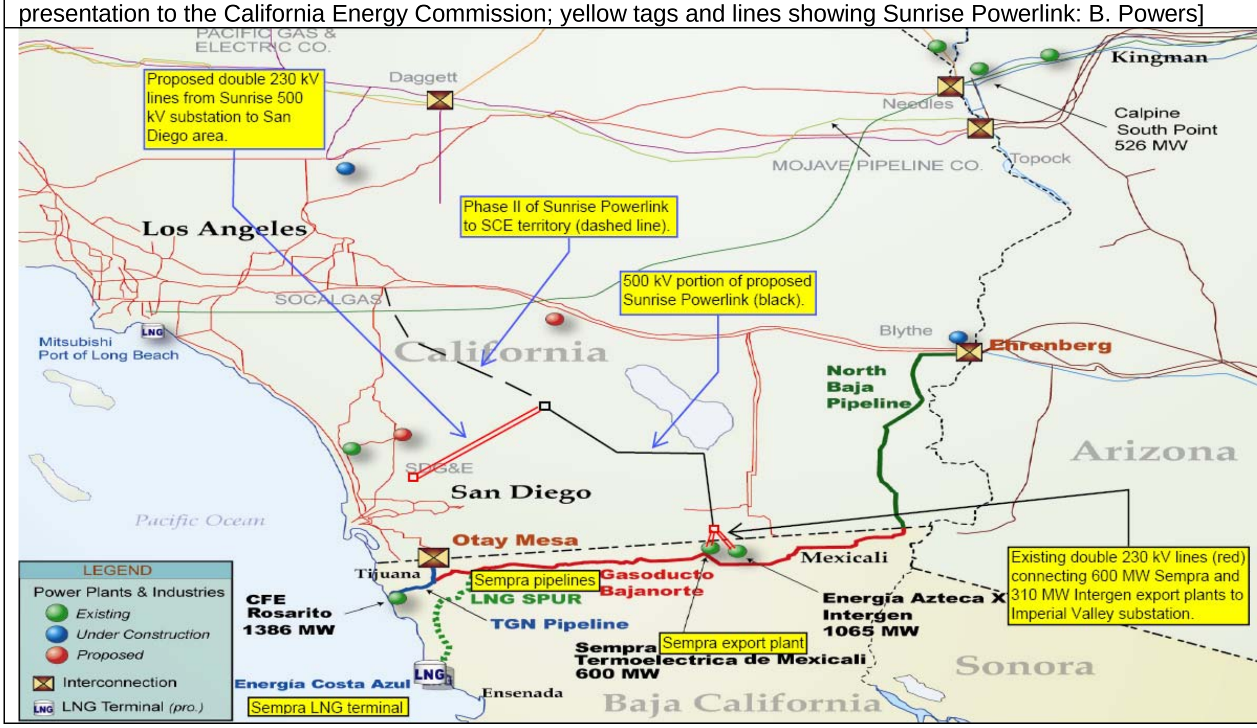


Figure B2. The transmission line will pass through the heart of Anza Borrego State Park. The 500 kV towers proposed by SDG&E will be considerably larger than the existing 69 kV transmission poles in the park. The park is home to the largest U.S. population of federally endangered peninsular bighorn sheep.

Figure B3. This map shows the interrelationship between the Sempra LNG terminal, Sempra natural gas pipelines, and the Sempra export power plant, all in Baja California, and the Sunrise Powerlink on the California side of the border. [source of base map: March 8, 2007 Sempra LNG presentation to the California Energy Commission; yellow tags and lines showing Sunrise Powerlink: B. Powers]



Attachment C: SDG&E Switch to LNG Will Negate Forecast GHG Reductions

SDG&E forecasts a 20 percent reduction in greenhouse gas (GHG) emissions between 2007 and 2016 in its Dec. 11, 2006 Long-Term Procurement Plan.[1] However, the SDG&E forecast does not account for reversal of flow on the SDG&E natural gas pipeline system in 2009 to move imported liquefied natural gas (LNG) from Sempra's LNG import terminal in Baja California to San Diego. Imported LNG carried a GHG burden that is approximately 25 percent greater than domestic natural gas.[2] The additional GHG burden is related to the high CO_2 content (10 percent) of the Indonesian raw gas that will be removed during gas processing[3] and the energy necessary to: 1) cryogenically liquefy natural gas into LNG, 2) transport the LNG across the Pacific in a specially-designed tankers, and 3) regasify the LNG back to gaseous form at Sempra's receiving terminal in Baja California.

All of the power sold by SDG&E in 2016 that produces CO_2 emissions will be generated by power plants burning natural gas.[4] See Figure 1. Approximately 50 percent of the natural gas sold by SDG&E is used in electric generation plants.[5] The remaining 50 percent is used primarily by commercial and residential customers for space heating, water heating, and cooking and related uses. All of this consumption will convert to natural gas derived from imported LNG when flow is permanently reversed on the SDG&E pipeline system in 2009. SDG&E's parent company Sempra Energy will begin operation of its 1,000 million cubic feet per day (mmcfd) Costa Azul LNG import terminal in 2008.[6] Sempra has preliminary approval from the CPUC to reverse flow on the SDG&E natural gas pipeline system to move this LNG from the Costa Azul LNG terminal directly into the San Diego market.[7] The CEC forecasts that this flow reversal will occur in 2009.[8,9]

The lifecycle GHG emissions from natural gas fired power plants in SDG&E service territory, and those served by the Baja California natural gas pipeline system which is interconnected with the Costa Azul LNG terminal, will increase by approximately 25 percent in 2009. As noted, all GHG-emitting power generation sources identified in the 2016 SDG&E forecast are natural gas-fired. Therefore, all CO_2 emissions forecast for 2016 shown in Figure 2 are from natural gas-fired sources. The result of the additional GHG associated with the lifecycle GHG burden of imported LNG will be to increase the SDG&E basecase CO_2 emission estimates for power generation shown in Figure 2 by 25 percent from 2009 forward. See the adjusted CO_2 estimate (red line) in Figure 2. This will nullify the decline in GHG emissions from 2007 to 2016 currently projected by SDG&E.

Lifecycle GHG emissions associated with imported LNG will eliminate the GHG reduction benefits of reaching 20 percent renewable energy generation by 2010 as mandated by AB 107. AB 32 requires a return to the 1990 GHG emission level by 2020. This is an estimated GHG reduction of 25 percent by 2020. The post-2020 phase of AB 32 is even more ambitious, targeting an 80 percent reduction in GHG by 2050. It is unlikely that SDG&E can achieve the 2020 AB 32 target if there is no net lifecycle reduction in GHG emissions from natural gas-fired combustion sources in SDG&E service territory in the 2007-2016 timeframe.

Sempra proposes to import LNG from British Petroleum's Tangguh, Indonesia LNG liquefaction plant. Figure 3 shows a graphic of the route from the liquefaction plant to Sempra's LNG import terminal near Ensenada.. Figure 3 also shows a breakdown of the 25 percent increase in lifecycle GHG emissions from each stage in the LNG process, from production of raw gas near Tangguh, processing and liquefaction of this gas, transport 7,500 miles to the LNG receiving terminal in Baja California, and regasification of the LNG for pipeline delivery to SDG&E service territory.

The current sources of natural gas supply to California are shown in Figure 4. The U.S. DOE domestic natural gas production forecast through 2025 is provided in Table 1. DOE is projecting a 14 percent increase in domestic natural gas production over the 2005-2025 period.

Figure 1. SDG&E Projection of Power Generation Sources to be Used to Meet Electricity Demand, 2007-2016[10]

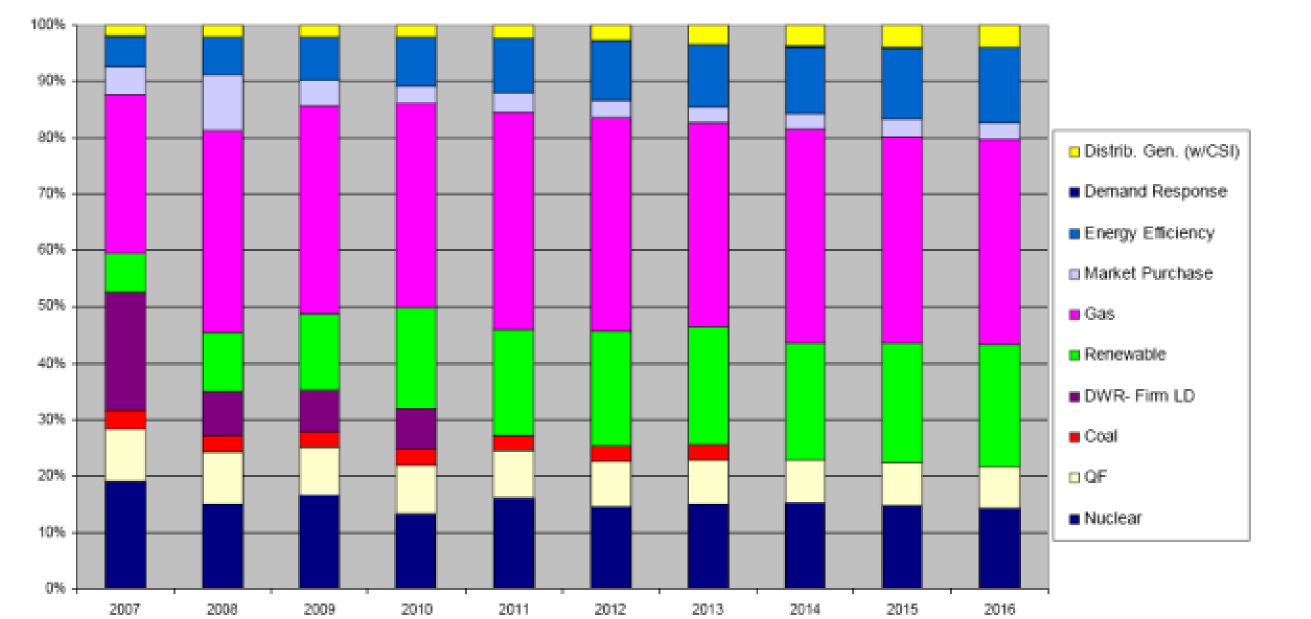


Figure 2. SDG&E Projection of Greenhouse Gas Emissions Trend, 2007-2016, and Powers Engineering Adjustment that Reflects the Lifecycle CO_2 Increase (from electric power generation only) Resulting from SDG&E Switch from Domestic Natural Gas to Imported LNG in 2009[11]

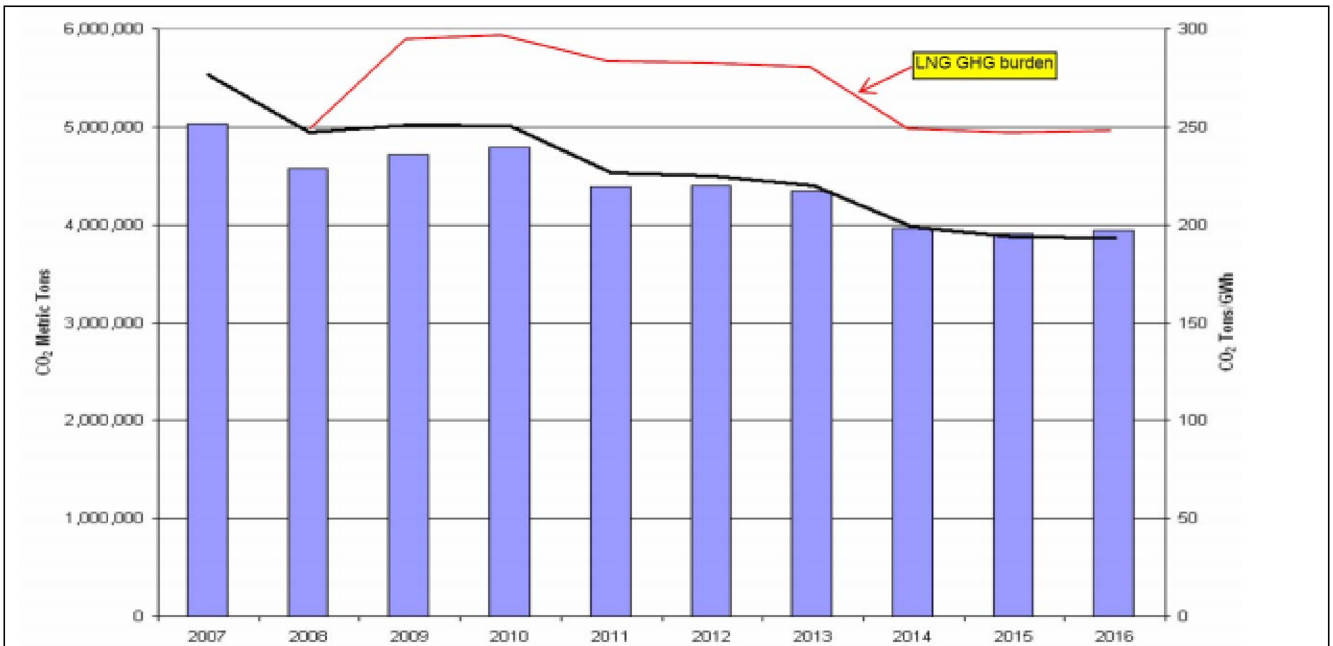


Figure 3. LNG versus Domestic Natural Gas: +25% Increase in Lifecycle Greenhouse Gas Emissions

Source of LNG supply chain graphics: Michelle Foss, Center for Energy Economics Bureau of Economic Geology, University of Texas-Austin, *LNG Access*, PowerPoint presentation, California Energy Commission LNG Access Workshop, June 1-2, 2005.
Source of Tangguh raw gas CO_2 content estimate: BP Indonesia webpage (www.bp.com) - "Greenhouse gas emissions - The natural gas in the Tangguh fields contains approximately 10% CO_2 - relatively high by industry standards."
Source of LNG supply chain greenhouse gas contribution estimates: P. Jaramillo, Carnegie-Mellon University, *Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, published online July 25, 2007.

Figure 4. Sources of California Natural Gas Supplies – 2006

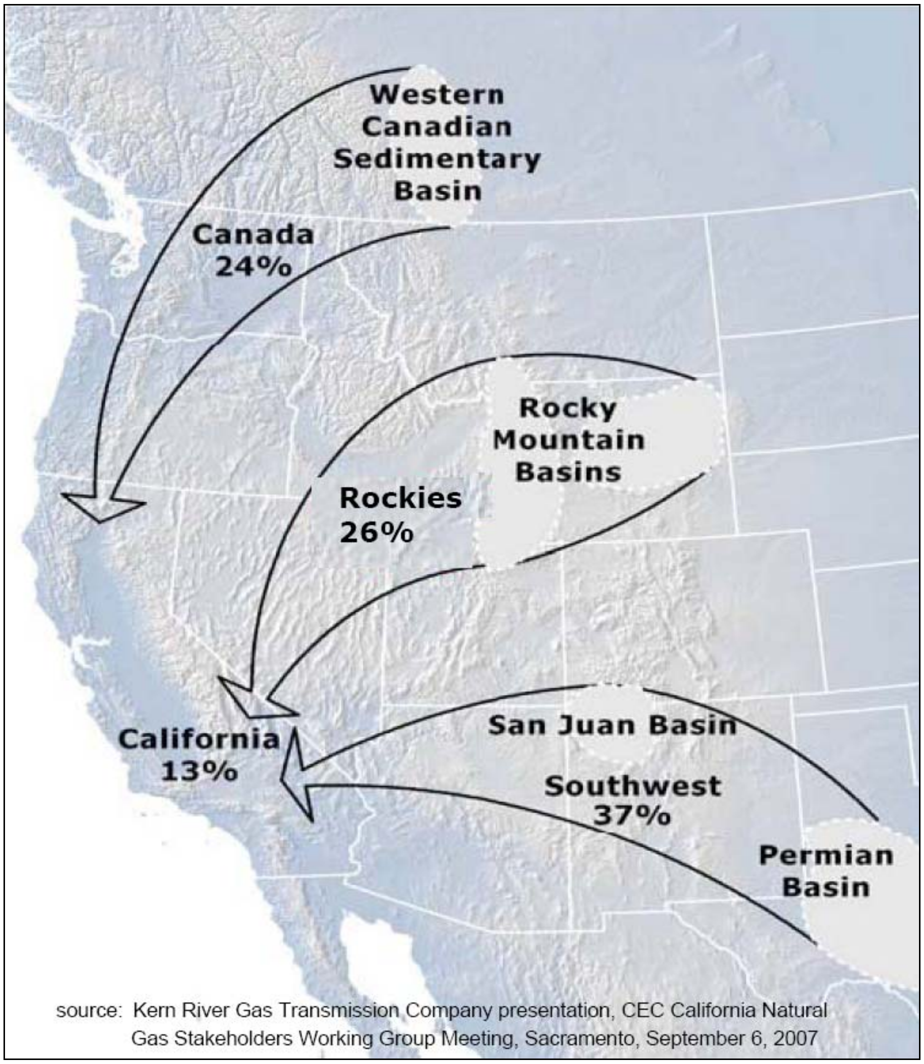


Table 1. U.S. DOE Domestic Natural Gas Production Forecast, 2005 – 2025[a]

Year	Domestic natural gas production[b] (trillion cubic feet)
2005	18.23
2010	19.35
2015	19.60
2020	20.79
2025	20.59

a) U.S. DOE Energy Information Administration, Annual Energy Outlook with Projections to 2030, Report DOE/EIA-0383, February 2007, p. 93. Tabular reference case natural gas production figures online at: http://www.eia.doe.gov/oiaf/aeo/pdf/aeotab_13.pdf

b) Reference case forecast is a 14% increase in U.S. domestic natural gas production from 2005 to 2020, from 18.23 trillion cubic feet per year to 20.79 trillion cubic feet per year.

[1] SDG&E 2007-2016 Long-Term Procurement Plan, December 11, 2006, p. 207.

[2] P. Jaramillo, Carnegie-Mellon University, *Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, published online July 25, 2007, and "Supporting Information" document. All CO_2 emission factors listed in this footnote are from the "Supporting Information" document. Assume the LNG is shipped from BP liquefaction plant in Tangguh, Indonesia, 7,500-mile tanker roundtrip to Sempra LNG regasification terminal in Baja California. The raw gas feeding the Tangguh liquefaction plant contains 10 percent CO_2 which will be vented to atmosphere at the plant (source: BP Indonesia webpage http://www.bp.com/sectiongenericarticle.do?categoryId=9004748&contentId=7008786). This is equivalent to a CO_2 emission rate of 12 lbs CO_2 per MMBtu, per the Carnegie-Mellon estimate of 120 lbs CO_2 per MMBtu of natural gas combusted. Assume average CO_2 generation from liquefaction (14 lb CO_2 per MMBtu without considering CO_2 content in raw gas). 7,500 miles is the same distance as Oman to the Everett, Massachusetts LNG terminal route cited in report, which generates 8 lb CO_2 per MMBtu in transport CO_2 emissions. Assume CO_2 generation from LNG regasification and storage is low due to use of seawater heating to regasify the LNG (1 lb CO_2 per MMBtu). Domestic natural gas emits a maximum of 140 lb CO_2 per MMBtu. Total additional CO_2 associated with LNG from Tangguh, Indonesia is 35 lb CO_2 per MMBtu. Incremental lifecycle CO_2 emissions associated with LNG imported from Tangguh are 35 lb CO_2 ÷ 140 lb CO_2 = 0.25, or a 25 percent increase in lifecycle CO_2 emissions.

[3] BP Indonesia webpage (www.bp.com) - "*Greenhouse gas emissions - The natural gas in the Tangguh fields contains approximately 10% CO_2 - relatively high by industry standards*." This CO_2 must be removed from the raw gas before the gas is liquefied. BP has made no commitment to sequester this CO_2 following removal during gas processing.

[4] Natural gas fired sources included in the 2016 SDG&E plan are "natural gas", "QF" – these are cogeneration plants firing natural gas, "market purchase", and a portion of "distributed generation". SDG&E identifies "market purchase" as having a CO_2 emission rate (915 lb CO_2 per MWh) similar to natural gas fired combined cycle generation (819 lb CO_2 per MWh). For this reason "market purchase is assumed to be natural gas-fired. All fossil fuel-fired cogeneration in SDG&E service territory is natural gas-fired.

[5] 2006 California Natural Gas Report, SDG&E Tabular Data, pp. 98-100. In 2010, electric generation consumes 175 mmcfd of 333 mmcfd total natural gas demand. In 2015, electric generation consumes 175 mmcfd of 348 mmcfd total demand. All other non-electric power generation combustion sources will consume 173 mmcfd in 2015.

[6] Sempra LNG website, Energia Costa Azul – Project Overview. www.sempralng.com.

[7] CPUC Decision 04-09-022, *Rulemaking 04-01-025 to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California*, Phase I, Sept. 2, 2004. Findings of Fact (p. 89): 38. There is potential California customer access to LNG supplies through Otay Mesa, Ehrenberg/Blythe, Oxnard and Long Beach. 39. Designating Otay Mesa as a common receipt point for both the SoCalGas and SDG&E systems will send a signal to potential LNG suppliers that the gas they provide will have access to the utilities' systems.

[8] California Energy Commission, *Natural Gas Market Assessment – Preliminary Results*, staff draft report, in support of CEC 2007 Integrated Energy Policy Report, CEC-200-2007-009-SD, May 2007, p. 23. "*Major findings regarding natural gas supply are: Importation of LNG is expected from Mexico into San Diego through the Transportadora De Gas Natural De Baja California (TGN) pipeline beginning in 2009. Gas imported from Costa Azul is projected to grow from zero to more than 1,500 MMcf per day by 2017*."

[9] J. Fore - CEC Natural Gas Unit, *2007 IEPR Natural Gas Forecast – Revised Reference Case*, PowerPoint presentation, August 16, 2007. Graphic on p. 26 shows natural gas from Costa Azul LNG terminal coming northward through Otay Mesa receipt point to San Diego at rate of 350 million cubic feet per day (mmcfd) in beginning in mid-2009. This flowrate is greater than the average daily natural gas demand forecast by SDG&E for 2010 of 333 mmcfd (see footnote 3). The revised August 16, 2007 LNG flow forecast shows LNG imports rising to 400 mmcfd through Otay Mesa in 2016, significantly less than the initial June 2007 reference case forecasting 1,000 mmcfd of LNG imports by 2016 (this case is also shown in the graphic on p. 26 of the PowerPoint).

[10] SDG&E summary of 2007-2016 LTPP to SANDAG Energy Working Group, January 25, 2007.

[11] The lifecycle CO_2 increase associated with the switch to LNG imports in 2009 is shown for electric power generation only. However, all stationary combustion sources using natural gas in SDG&E service territory will be using natural gas originating at the Costa Azul LNG terminal from mid-2009 onward. As a result, these sources will also see a 25 percent increase in lifecycle CO_2 emissions. Non-electric power generation natural gas consumption in SDG&E service territory will average 173 mmcfd in 2015. The CO_2 emission factor for natural gas consumption is 117 lb CO_2 per million Btu of natural gas combustion (source: SDG&E Dec. 11, 2006 Long-Term Procurement Plan , Vol. I, p. 207). The heating value of natural gas is approximately 1,000 Btu's per cubic foot. Therefore, the forecast CO_2 emissions from non-electric power generation natural gas combustion in SDG&E service territory in 2015 is [173 mmcfd × (1,000 × 10^6 Btu/mmcfd) × 117 lb $CO_2/10^6$ Btu]/2,000 lb/ton = 10,120 tons per day, or 3,694,000 tons per year of CO_2. An increase of 25 percent in these non-electric power generation CO_2 emissions, representing the lifecycle CO_2 emissions increase resulting from the switch from domestic natural gas to LNG, is an increase of 920,000 tons per year of CO_2.

Attachment D: Population Forecast Used by SDG&E in 10-Year Plan

Mnemonic:	FPOPQ.MSAN	FPOPQ.MSAN	**Mnemonic:**	FPOPQ.MSAN	FPOPQ.MSAN		
Description:	Total Populatio	Total Populatio	**Description:**	Total Populatio	Total Population, (Ths.)		
Source:	BOC; Moody's I	BOC; Moody's I	**Source:**	BOC; Moody's I	BOC; Moody's Economy.com		
Native Freq	QUARTERLY	QUARTERLY	**Native Freque**	QUARTERLY	QUARTERLY		
Geography:	San Diego-Carl	San Diego-Carl	**Geography:**	San Diego-Carl	San Diego-Carlsbad-San Marcos, CA Metropolitan Statistical Area		
Last Update	05/17/2007	05/17/2007	**Last Updated:**	05/17/2007	05/17/2007		
1970Q2	1357.85	na	**Dec-1970**	1367.74	na		
1970Q3	1368.35	na	**Dec-1971**	1396.18	2.08		
1970Q4	1377.02	na	**Dec-1972**	1442.52	3.32		
1971Q1	1384.62	na	**Dec-1973**	1503.31	4.21		
1971Q2	1391.90	2.51	**Dec-1974**	1551.99	3.24		
1971Q3	1399.63	2.29	**Dec-1975**	1618.65	4.30		
1971Q4	1408.57	2.29	**Dec-1976**	1652.38	2.08		
1972Q1	1419.47	2.52	**Dec-1977**	1723.08	4.28		
1972Q2	1433.10	2.96	**Dec-1978**	1782.05	3.42		
1972Q3	1449.73	3.58	**Dec-1979**	1833.39	2.88		
1972Q4	1467.76	4.20	**Dec-1980**	1881.93	2.65		
1973Q1	1485.08	4.62	**Dec-1981**	1932.65	2.69		
1973Q2	1499.60	4.64	**Dec-1982**	1978.08	2.35		
1973Q3	1510.06	4.16	**Dec-1983**	2023.96	2.32		
1973Q4	1518.49	3.46	**Dec-1984**	2073.68	2.46		
1974Q1	1527.75	2.87	**Dec-1985**	2134.87	2.95		
1974Q2	1540.70	2.74	**Dec-1986**	2206.35	3.35		
1974Q3	1559.11	3.25	**Dec-1987**	2286.67	3.64		
1974Q4	1580.40	4.08	**Dec-1988**	2374.37	3.84		
1975Q1	1600.89	4.79	**Dec-1989**	2453.58	3.34		
1975Q2	1616.90	4.95	**Dec-1990**	2517.11	2.59		
1975Q3	1626.01	4.29	**Dec-1991**	2559.04	1.67		
1975Q4	1630.81	3.19	**Dec-1992**	2593.53	1.35	0.94%	1992-2006
1976Q1	1635.13	2.14	**Dec-1993**	2601.93	0.32		15-yr ave.
1976Q2	1642.80	1.60	**Dec-1994**	2615.40	0.52		
1976Q3	1656.59	1.88	**Dec-1995**	2626.93	0.44		
1976Q4	1675.01	2.71	**Dec-1996**	2656.75	1.14		
1977Q1	1695.50	3.69	**Dec-1997**	2697.78	1.54		
1977Q2	1715.50	4.43	**Dec-1998**	2743.84	1.71		
1977Q3	1733.01	4.61	**Dec-1999**	2793.82	1.82		
1977Q4	1748.29	4.37	**Dec-2000**	2829.83	1.29		

1978Q1	1762.15	3.93	**Dec-2001**	2869.61	1.41					
1978Q2	1775.40	3.49	**Dec-2002**	2904.30	1.21					
1978Q3	1788.68	3.21	**Dec-2003**	2923.52	0.66					
1978Q4	1801.96	3.07	**Dec-2004**	2934.29	0.37					
1979Q1	1815.00	3.00	**Dec-2005**	2937.04	0.09					
1979Q2	1827.60	2.94	**Dec-2006**	2943.21	0.21	1.03%	1997-2006	0.75%	2000-2006	0.22%
1979Q3	1839.63	2.85	**Dec-2007**	2953.07	0.34		10-yr ave.		7-yr ave.	2004-2006
1979Q4	1851.35	2.74	**Dec-2008**	2968.65	0.53					3-yr ave.
1980Q1	1863.11	2.65	**Dec-2009**	3003.92	1.19	0.73%	2000-2009			
1980Q2	1875.28	2.61	**Dec-2010**	3048.35	1.48		10-yr ave.			
1980Q3	1888.09	2.63	**Dec-2011**	3096.12	1.57					
1980Q4	1901.25	2.70	**Dec-2012**	3145.90	1.61					
1981Q1	1914.36	2.75	**Dec-2013**	3195.59	1.58					
1981Q2	1927.02	2.76	**Dec-2014**	3246.12	1.58					
1981Q3	1938.93	2.69	**Dec-2015**	3297.27	1.58					
1981Q4	1950.28	2.58	**Dec-2016**	3348.66	1.56	1.30%	2007-2016			
1982Q1	1961.32	2.45	**Dec-2017**	3399.61	1.52		10-yr ave.			
1982Q2	1972.36	2.35	**Dec-2018**	3450.34	1.49					
1982Q3	1983.60	2.30	**Dec-2019**	3501.83	1.49	1.55%	2010-2019			
1982Q4	1995.03	2.29	**Dec-2020**	3554.11	1.49		10-yr ave.			
1983Q1	2006.57	2.31	**Dec-2021**	3605.00	1.43					
1983Q2	2018.13	2.32	**Dec-2022**	3655.54	1.40					
1983Q3	2029.69	2.32	**Dec-2023**	3706.26	1.39					
1983Q4	2041.44	2.33	**Dec-2024**	3756.77	1.36					
1984Q1	2053.60	2.34	**Dec-2025**	3807.28	1.34					
1984Q2	2066.42	2.39	**Dec-2026**	3855.32	1.26					
1984Q3	2080.08	2.48	**Dec-2027**	3901.71	1.20					
1984Q4	2094.61	2.60	**Dec-2028**	3947.72	1.18					
1985Q1	2109.95	2.74	**Dec-2029**	3994.00	1.17					
1985Q2	2126.09	2.89	**Dec-2030**	4039.30	1.13					
1985Q3	2142.97	3.02	**Dec-2031**	4082.45	1.07					
1985Q4	2160.47	3.14	**Dec-2032**	4127.07	1.09					
1986Q1	2178.47	3.25	**Dec-2033**	4173.63	1.13					
1986Q2	2196.83	3.33	**Dec-2034**	4222.50	1.17					
1986Q3	2215.49	3.38	**Dec-2035**	4274.91	1.24					
1986Q4	2234.63	3.43	**Dec-2036**	4330.02	1.29					
1987Q1	2254.49	3.49			7.29					

1987Q2	2275.30	3.57
1987Q3	2297.19	3.69
1987Q4	2319.70	3.81
1988Q1	2342.26	3.89
1988Q2	2364.29	3.91
1988Q3	2385.36	3.84
1988Q4	2405.57	3.70
1989Q1	2425.16	3.54
1989Q2	2444.39	3.39
1989Q3	2463.33	3.27
1989Q4	2481.44	3.15
1990Q1	2498.02	3.00
1990Q2	2512.37	2.78
1990Q3	2524.07	2.47
1990Q4	2534.00	2.12
1991Q1	2543.29	1.81
1991Q2	2553.12	1.62
1991Q3	2564.21	1.59
1991Q4	2575.53	1.64
1992Q1	2585.66	1.67
1992Q2	2593.13	1.57
1992Q3	2597.00	1.28
1992Q4	2598.35	0.89
1993Q1	2598.75	0.51
1993Q2	2599.78	0.26
1993Q3	2602.58	0.21
1993Q4	2606.63	0.32
1994Q1	2610.98	0.47
1994Q2	2614.69	0.57
1994Q3	2617.11	0.56
1994Q4	2618.82	0.47
1995Q1	2620.72	0.37
1995Q2	2623.70	0.34
1995Q3	2628.43	0.43
1995Q4	2634.85	0.61
1996Q1	2642.65	0.84
1996Q2	2651.55	1.06

1996Q3	2661.27	1.25
1996Q4	2671.54	1.39
1997Q1	2682.07	1.49
1997Q2	2692.60	1.55
1997Q3	2702.97	1.57
1997Q4	2713.48	1.57
1998Q1	2724.59	1.59
1998Q2	2736.72	1.64
1998Q3	2750.08	1.74
1998Q4	2763.96	1.86
1999Q1	2777.44	1.94
1999Q2	2789.59	1.93
1999Q3	2799.77	1.81
1999Q4	2808.47	1.61
2000Q1	2816.48	1.41
2000Q2	2824.93	1.27
2000Q3	2834.04	1.22
2000Q4	2843.87	1.26
2001Q1	2854.14	1.34
2001Q2	2864.59	1.40
2001Q3	2874.93	1.44
2001Q4	2884.80	1.44
2002Q1	2893.85	1.39
2002Q2	2901.72	1.30
2002Q3	2908.17	1.16
2002Q4	2913.44	0.99
2003Q1	2917.87	0.83
2003Q2	2921.81	0.69
2003Q3	2925.52	0.60
2003Q4	2928.90	0.53
2004Q1	2931.76	0.48
2004Q2	2933.93	0.41
2004Q3	2935.35	0.34
2004Q4	2936.13	0.25
2005Q1	2936.48	0.16
2005Q2	2936.61	0.09
2005Q3	2937.18	0.06

2005Q4	2937.89	0.06		
2006Q1	2939.23	0.09		
2006Q2	2941.45	0.16	0.095%	ave. pop.
2006Q3	2944.74	0.26		Growth, last
2006Q4	2947.43	0.32		
2007Q1	2950.27	0.38		
2007Q2	2952.61	0.38	0.334%	
2007Q3	2953.61	0.30		
2007Q4	2955.80	0.28		
2008Q1	2959.97	0.33		
2008Q2	2964.80	0.41	0.332%	
2008Q3	2971.14	0.59		
2008Q4	2978.68	0.77		
2009Q1	2988.34	0.96		
2009Q2	2998.44	1.13	0.865%	
2009Q3	3009.11	1.28		
2009Q4	3019.77	1.38		
2010Q1	3030.81	1.42		
2010Q2	3042.63	1.47	1.388%	
2010Q3	3054.23	1.50		
2010Q4	3065.72	1.52		
2011Q1	3077.73	1.55		
2011Q2	3090.08	1.56	1.532%	
2011Q3	3102.16	1.57		
2011Q4	3114.51	1.59		
2012Q1	3127.02	1.60		
2012Q2	3139.62	1.60	1.591%	
2012Q3	3152.21	1.61		
2012Q4	3164.78	1.61		
2013Q1	3177.29	1.61		
2013Q2	3189.59	1.59	1.607%	
2013Q3	3201.73	1.57		
2013Q4	3213.77	1.55		
2014Q1	3226.73	1.56		
2014Q2	3239.68	1.57	1.561%	
2014Q3	3252.60	1.59		
2014Q4	3265.49	1.61		

2015Q1	3278.25	1.60	
2015Q2	3290.97	1.58	1.594%
2015Q3	3303.63	1.57	
2015Q4	3316.24	1.55	
2016Q1	3329.20	1.55	
2016Q2	3342.17	1.56	1.558%
2016Q3	3355.14	1.56	
2016Q4	3368.12	1.56	
2017Q1	3380.73	1.55	
2017Q2	3393.33	1.53	1.551%
2017Q3	3405.93	1.51	
2017Q4	3418.44	1.49	
2018Q1	3431.25	1.49	
2018Q2	3443.95	1.49	
2018Q3	3456.63	1.49	
2018Q4	3469.52	1.49	
2019Q1	3482.25	1.49	
2019Q2	3495.22	1.49	
2019Q3	3508.35	1.50	
2019Q4	3521.47	1.50	
2020Q1	3534.66	1.50	
2020Q2	3547.72	1.50	
2020Q3	3560.64	1.49	
2020Q4	3573.43	1.48	
2021Q1	3586.04	1.45	
2021Q2	3598.67	1.44	
2021Q3	3611.32	1.42	
2021Q4	3623.98	1.41	
2022Q1	3636.61	1.41	
2022Q2	3649.11	1.40	
2022Q3	3661.84	1.40	
2022Q4	3674.58	1.40	
2023Q1	3687.33	1.39	
2023Q2	3700.00	1.39	
2023Q3	3712.57	1.39	
2023Q4	3725.15	1.38	
2024Q1	3737.73	1.37	

2024Q2	3750.40	1.36
2024Q3	3763.11	1.36
2024Q4	3775.84	1.36
2025Q1	3788.54	1.36
2025Q2	3801.16	1.35
2025Q3	3813.61	1.34
2025Q4	3825.82	1.32
2026Q1	3837.79	1.30
2026Q2	3849.50	1.27
2026Q3	3861.18	1.25
2026Q4	3872.82	1.23
2027Q1	3884.44	1.22
2027Q2	3896.01	1.21
2027Q3	3907.48	1.20
2027Q4	3918.91	1.19
2028Q1	3930.42	1.18
2028Q2	3941.92	1.18
2028Q3	3953.49	1.18
2028Q4	3965.06	1.18
2029Q1	3976.62	1.18
2029Q2	3988.20	1.17
2029Q3	3999.81	1.17
2029Q4	4011.37	1.17
2030Q1	4022.87	1.16
2030Q2	4033.91	1.15
2030Q3	4044.80	1.12
2030Q4	4055.63	1.10
2031Q1	4066.38	1.08
2031Q2	4077.11	1.07
2031Q3	4087.78	1.06
2031Q4	4098.52	1.06
2032Q1	4109.80	1.07
2032Q2	4121.24	1.08
2032Q3	4132.81	1.10
2032Q4	4144.44	1.12
2033Q1	4156.09	1.13
2033Q2	4167.74	1.13

2033Q3	4179.45	1.13
2033Q4	4191.25	1.13
2034Q1	4203.32	1.14
2034Q2	4215.81	1.15
2034Q3	4228.73	1.18
2034Q4	4242.13	1.21
2035Q1	4255.12	1.23
2035Q2	4268.25	1.24
2035Q3	4281.50	1.25
2035Q4	4294.79	1.24
2036Q1	4308.84	1.26
2036Q2	4322.92	1.28
2036Q3	4337.06	1.30
2036Q4	4351.25	1.31

SANDAG

Energy Working Group
January 25, 2007

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September 8, 2006 File Number 3003000

Mr. William Reed
Senior Vice President, Regulatory and Strategic Planning
San Diego Gas and Electric Company
8306 Century Park Court, Suite 41D
San Diego, CA 92123-1530

Dear Mr. Reed:

SUBJECT: SANDAG Recommendations on SDG&E's Long-Term Procurement Plan

The San Diego Association of Governments Energy Working Group (SANDAG EWG), in cooperation with SDG&E, has had the opportunity to raise questions about and collaborate on future SDG&E energy resource planning and procurement policies. Following an extensive fact-finding project with stakeholders from businesses, environmental groups, and local governments, SANDAG has developed policy guidelines and recommendations for SDG&E to use in moving toward the goals of the San Diego Regional Energy Strategy 2030 (RES), which favors a balanced approach to energy policy issues. These recommendations are to offer guidance to SDG&E in its mandated Long-Term Procurement Plan (LTPP) submittal to the state.

The RES was written by a regional stakeholder group formed as a product of the Regional Energy Infrastructure Study (REIS), prepared in 2002. For over a year, these stakeholders held meetings and reached consensus on the goals for the San Diego region's energy policy. The RES's short-term quantitative assumptions were ultimately voted on and adopted by the SANDAG Board of Directors in 2003 as an energy planning tool for the region. The SANDAG Board also voiced its commitment to revisit the longer-term goals of the RES as needed.

The SDG&E LTPP serves as a roadmap for how the utility plans to address San Diego's resource needs for the next 10 years. In SDG&E's LTPP filing, SANDAG looks for carefully thought out, long-term goals that satisfy a number of concerns, rather than offering quick fixes for the region's energy shortfalls. With respect to renewables and distributed generation procurement goals, SDG&E's goals should be aggressive in the short-term, building up to more aggressive goals in subsequent years.

The following are SANDAG's policy recommendations for SDG&E to consider and implement in its long-term planning, including its upcoming LTPP filing to the California Public Utilities Commission (CPUC).

- Focus on California's preferred loading order
- Evaluate technologies' costs and benefits
- Support renewable energy technologies
- Support distributed generation technologies
- Support in-region generation

Focus on California's Preferred Loading Order

One of the RES Guiding Principles states that, "Energy efficiency and demand management programs will be preferred over the development of new fossil fuel generation resources." In its procurement activities, SDG&E must follow the state-approved loading order, which gives highest priority to energy efficiency and demand response when planning for the state's energy future. These energy-saving measures are followed in priority order by renewable energy and distributed generation, conventional large-scale generation and transmission respectively.

The state's top priorities must also be SDG&E's. The LTPP submittal should clearly demonstrate how the utility is meeting or exceeding the state-mandated energy-saving targets for energy efficiency and demand response followed by renewables and distributed generation. Information imparted to the public should be as accurate, complete, and understandable as possible.

Evaluation of Technologies' Costs and Benefits

Other RES Guiding Principles emphasize an energy supply portfolio that is diversified, cost efficient, environmentally sound, self sustaining, secure, and reliable. A planned approach for procurement should involve developing metrics for evaluation of prospective conventional and renewable technologies. Scoring criteria for each technology should include, but not be confined to, the following:

- *Cost-effectiveness to ratepayers*-All technologies that are selected by SDG&E for their long-term plans need to ensure the costs incurred by ratepayers on a project do not increase their bills unduly or unreasonably, if at all.

- *Cost-effectiveness to systems*-Projects that are selected by SDG&E should not propose higher than reasonable costs to be expended to develop needed technologies.

- *Role in global warming*-Projects should advance the state toward baseline GHG emission standards, e.g. the Governor's Executive Order S-3-05, which states specific reduction goals for California and Assembly Bill 32, which passed the legislature in August 2006.

- *Community economic impact*-A broader set of guidelines reviewing costs related to pollution mitigation, health risks, aesthetic impacts, jobs, etc.

- *Sensitivity to gas supply risk*-When determining the cost of a project, SDG&E should take the cost and projected price volatility of natural gas into consideration as a component of the total cost for the project.

In project evaluation, SDG&E has noted that it already favors those projects that have the least environmental impact, that have the ability to meet specific reliability timelines, and that are the most cost-effective. SANDAG's goal is to recommend enhancements to this procurement procedure to ensure a more open and transparent process. The utility's request for proposals (RFP) should provide prospective developers with the information they need to submit relevant projects to meet San Diego's resource needs. After completion of each bid process, SDG&E could alert all bidders as to why their proposals were accepted or rejected. This could continually improve the solicitation process and quality of bids.

Support for Renewable Energy Technologies

- The RES goal #3 states, "Increase the total electricity supply from renewable resources with an emphasis on in-region installations,"[1] and includes a target of 50 percent of those renewables from in-region. Therefore, it is imperative that SDG&E supports all economically and technically feasible renewable energy technologies. This is especially true for rooftop photovoltaic systems and central plant solar, wind, and geothermal systems as mentioned in the 2005 study: *Potential for Renewable Energy in the San Diego Region*.

- In order to achieve the state's Renewable Portfolio Standard (RPS) goals, SANDAG supports the establishment of in-region "renewable energy parks" and the streamlining of the permitting and transmission process for access to these parks. This measure could effectively intensify interest in renewables in the region. In addition to large-scale projects, this could promote research, development and demonstration (RD&D) projects by greatly expanding the amount of renewable technologies available to study within the San Diego region. RD&D could include next generation renewable technologies as well as studies on the maturity of existing technologies, like fuel cells and combined heat and power (CHP) systems utilizing renewable fuel. These measures will produce vital information for SDG&E and other decision-making bodies that shape energy policy, and will reflect an accurate picture of the energy sources available and their associated costs.

- In addition to this goal, locally placed renewables within and outside of renewable energy parks should be incentivized prior to providing incentives for out-of-region renewables. As part of any RFP bid evaluation, SDG&E should include significant weighting for renewable projects.

- Another issue gaining importance for renewable energy development is ownership of credits that contribute to the state's RPS goals. The CPUC is currently addressing this complex issue for the entire state. Once the CPUC establishes which resources can be counted toward the utilities' RPS goals with Renewable Energy Credits (RECs) and which cannot, SANDAG can revisit how this may or may not impact our regional renewable goals.

Support for Distributed Generation Technologies

RES goal #4 addresses the desire to increase the amount of distributed generation in the San Diego region. This is an area where there has not been significant progress toward the RES goal. SANDAG supports efforts to more aggressively reach the distributed generation target of 12 percent of peak demand by 2010, and recommends that SDG&E also take additional steps to reach this goal. Measures can include supporting the continuation of the Self Generation Incentive Program (SGIP), which provides incentives for distributed generation (DG) projects. (This program is currently scheduled to sunset December 31, 2007.)

Another measure can be an assessment of any barriers in the utility's rate and tariff structures available for end-users who are interested in taking advantage of distributed generation. For

[1] Energy 2030: The San Diego Regional Energy Strategy, May 2003, www.sdenergy.org

instance, the noncoincident peak demand tariff may be cost prohibitive for clean onsite DG use. Although these measures may not directly correlate to the long-term procurement plan filing, SANDAG would appreciate added attention to be given to enhancing the role of distributed generation in the San Diego region. SANDAG, through its Energy Planning program and the EWG, is poised to work with SDG&E and regional stakeholders in this area, both on technology development and on regulatory efforts.

Support In-Region Generation

With regard to renewable and nonrenewable electric generation in the region, SANDAG requests that all cost-effective and viable large-scale in-region generation projects be considered in SDG&E's procurement plans. RES goal #2 calls for achieving and maintaining capacity to generate 65 percent of summer peak demand with in-county generation by 2010.

Sunrise Transmission Project to be Addressed Separate from these Recommendations

RES goal #5 calls for an increase in the transmission system capacity as necessary to maintain required reliability and to promote better access to renewable resources and competitively priced supply. The transmission grid provides for a number of functions, including providing access to out of region power, improving fuel diversity (in particular, renewables), providing access to broader supplies in the market that can help lower and stabilize electric prices, and improving system stability and reliability. These benefits need to be balanced with the fact that siting issues for new transmission lines are often contentious and difficult to achieve due to the large number of parties that are affected by such projects (e.g. visual impacts, potential impacts on property values, concerns for the impacts of electric and magnetic fields). Subsequent to this letter, SANDAG will review the Sunrise Powerlink as it correlates to all aspects of the RES, including the impact on in-region renewable and nonrenewable generation.

We look forward to reviewing your draft submittal of the LTPP prior to your filing with the Public Utilities Commission. We also would like to thank you for the occasion to participate in the LTPP process as a planning partner, and look forward to an ongoing collaborative relationship in this realm.

Sincerely,

MICKEY CAFAGNA
Chair, SANDAG Board of Directors

MC:RR:dd

cc: Commissioner Michael Peevey, CPUC
Administrative Law Judge Carol Brown, CPUC
Senator Christine Kehoe, Chair, Senate Energy, Utilities and Communications Committee

Attachment F: Summary of Strategic Energy Assessments for San Diego Region

1. Energy Parks to Balance Renewable Energy in San Diego Region
(R. Caputo, B. Butler, July 2007)

The current regional energy goal in San Diego is 40 percent renewable electricity by 2030, and having 50 percent come from within San Diego County. In-county land availability is fractured with sizes less than 200 acres at a site. To use this in-country resource, from 50 to 150 smaller solar plants would be required to match the power of one large desert plant. The concept of “energy parks” was suggested to overcome this barrier to in-county renewables and would allow multiple plant sites to be readied for construction and placed in a renewable energy land bank.

A new 64 MW parabolic trough plant by Solargenix is under construction in the Eldorado Valley Solar Energy Park created by Boulder City, Nevada. This is the first solar energy park created in the southwest. We have used this as a model for the Renewable Energy Parks proposed for San Diego County.

Concentrating photovoltaic systems (CPV) are making significant strides. A prototype 1 MW plant was built by Amonix for Arizona Public Service has been operating for several years, and a second 1 MW plant is being built by Sharp for Nevada Power. Concentrations of 400 to 1000 suns are used and cell efficiencies of 28 to 40 percent are achieved, with solar to AC electric efficiencies of 18 to 25 percent.

Flat plate photovoltaics (PV) are used on or near buildings. This is the only distributed solar technology considered and it holds great promise especially because of the recently enacted California Solar Initiative (CSI) program. The California Energy Commission goal for all of California is that 3,000 MW on-site PV be in place in 10 years. For the San Diego region, about 10 percent of this is expected. At the present time, about 30 MW of on-building PV exists in San Diego.

The more remote eastern half of San Diego County is the suggested region for the smaller concentrating solar plants (CSP) that would not require transmission lines to bring the power to the urban center. First of all, what are the characteristics of the available land?

The best match between the smaller (<200 acres) parcels of rolling land in the rural eastern part of San Diego County and the four CSP technologies, is the dish-Stirling and the CPV systems. If 10 percent of the total available land is used as the technical potential of this resource, then 20,740 acres are available. This translates to a technical potential close to 4,000 MW. This is significant since the current peak power demand of the San Diego region is 4,500 MW and the peak load (air conditioning) occurs when the sun is most intense.

The major assumption that this analysis rests on is the creation and vigorous implementation of renewable energy parks with-in San Diego County. It is unlikely that solar energy plant contractors would willingly attempt to site over 1,100 MW of capacity sprinkled over 50 to 150 sites. They would rather pick one or two desert sites to accomplish this and let others worry about constructing transmission lines to the city. The difficulty of about 100 sets of siting would deter all but the very strong hearted.

The energy park idea is to remove most of the initial barriers to small power plant siting. This would involve the plant site to be chosen, the land to be purchased or leased, the zoning changes arranged, the local, county, state and federal (if needed) approval process to be started along with "generic" environment impact assessment. The local grid connection and other utilities would be arranged and the site readied for start of plant construction. This site would be put in the energy land bank and thus made available for rapid plant startup when the date was established for the needed power and the local utility sought to sign a power purchase agreement with a power plant builder.

This 50/50 goal was generated by SANDAG. SANDAG has as it members all 19 local political entities in San Diego County. The proactive support of the separate political entities that make up the SANDAG board, by streamlining their internal procedures, would make a major contribution to bringing this concept to life.

A two step approach is recommended. The first step would be taken by the local political entities (some of the 19 local jurisdictions in San Diego County) to streamline their evaluation and approval process to expedite the processing of the 100 or so small power plants. The second step is for San Diego County to contribute to the up-front costs for studies and the land acquisition or lease. The second step could also be taken by SANDAG to petition the CPUC to support the renewable energy park concept and establish the procedures to authorize and allow funding of all the activities needed to create the energy park.

2. Creating a Sustainable Economy – San Diego/Tijuana Case Study

(Jim Bell, 2nd edition, March 2007)

Jim Bell is a sustainable resource planner who has been heavily involved in energy planning in the San Diego area for many years. The second edition of his book "*Creating a Sustainable Economy and Future on Our Planet - San Diego/Tijuana Region Case Study*" was published in March 2007. Mr. Bell's analysis emphasizes the development of a sustainable local energy economy through maximum use of commercial and residential PV systems. The main elements of his analysis for achieving energy self-sufficiency are described in the following paragraphs.

> "Our region is so rich in renewable energy resources that we could easily become energy self-sufficient even without energy-use efficiency improvements. For example, even with zero efficiency improvements, San Diego County could be self-sufficient for electricity by 2050 if 34 percent (48 square miles) of the 140 square miles of county land projected to be covered by roofs and parking lots in 2050 were covered by photovoltaic (PV) systems. For comparison, in 2005, an estimated 110 square miles of county land was already covered by roofs and parking lots.
>
> With a 40 percent increase in PV efficiency only 20 percent (29 square miles) of the county's roofs and parking lots would need to be covered for the county to be self-sufficient for electricity through 2050. Without efficiency improvements, covering 86 percent (121 square miles) of our county's projected 140 square miles of roofs and parking lots in 2050 with PV systems would produce enough electricity to replace all the imported energy projected to be used in San Diego County in that year. With a 40 percent increase in energy use efficiency,

only 52 percent (73 square miles) of the county's roofs and parking lots would need to be covered with PV systems for San Diego County to be self-sufficient for all energy sources through 2050. Coupling a 40 percent improvement in efficient energy use with covering 100 square miles of roofs and parking lots with PV systems, the county would become a large energy exporter. An additional 37 square miles of PV production at $0.10 per kWh would bring in $1.8 billion per year of revenue.

At $0.10 per kWh, regional energy self-sufficiency in 2002 would have kept about $7 billion in San Diego/Tijuana region, $5.2 billion in San Diego County alone. According to economic multiplier theory, adding $7 billion to our local economy each year would increase local yearly economic activity by $14 billion."

3. Green Energy Options to Replace the South Bay Power Plant
(Local Power, February 2007, prepared for Environmental Health Coalition)

The Green Energy Options (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 GEOs provide three levels of capacity replacement relative to the current 700 MW power plant. The nominal capacity of the GEO options range between 660MW and 1,150 MW, 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".

The targets are established as meeting 50 percent, 70 percent and 90 percent of the current South Bay Power Plant's capacity for supplying power during the hours of peak demand. Thus the portfolio is 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. A summary of the energy replacement options for South Bay are provided in the following table:

Summary of Energy Portfolio Replacement Options for South Bay

Facility	50 percent		70 percent		90 percent	
	MW	GWh	MW	GWh	MW	GWh
Wind farm	150	460	325	990	400	1,200
Pumped water storage	60	250	90	250	150	420
Concentrating solar	160	450	160	450	160	450
Natural gas peaker	90	250	190	530	240	670
PV	20	30	20	30	20	30
Peak demand reduction	20	35	20	35	20	35
Transmission	--	--	--	--	--	--
Replacement target (MW)	350		490		630	
Electricity generation (GWh)	1,270		1,960		2,270	
Ave. peak power cost (¢/kWh)	8.7-10.4		8.4-10.8		8.5-10.3	

Community Choice Aggregation (CCA) is the best approach to eliminating the need for power generation at the South Bay site. 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.

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.

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 ensure 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.

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.

Renewable and conservation facility assets will retain their market value and generate revenue after the revenue 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.

4. Potential for Renewable Energy in the San Diego Region

(San Diego Regional Renewable Energy Study Group, August 2005, www.renewablesg.org)

The purpose of this study was to estimate the size of the regional renewable energy resource base and the approximate cost of renewable energy power generation. The projected regional renewable energy technical potential is summarized in the following table:

Region's Renewable Energy Technical Potential in 2020[1]

SOLAR PV - Commercial and Residential			SOLAR - Concentrating Solar Power (CSP)			WIND		
	Capacity (MW AC)	Energy (GWh)		Capacity (MW AC)	Energy (GWh)		Capacity (MW)	Energy (GWh)
SD County	4,691	10,224	SD County	2,900	5,080	SD County & Parts of Imperial County and Northern Baja California, Mexico		
			Imperial County	29,000	50,808		1,650 - 1,830	4,530 - 5,020

BIOMASS (SD County)			SMALL HYDRO			GEOTHERMAL		
	Capacity (MW)	Energy (GWh)		Capacity (MW)	Energy (GWh)		Capacity (MW)	Energy (GWh)
Landfill Gas	72	505	SD County	8.32	15	Imperial County	2,500	22,000
			Imperial County	86.5	152			
Other Biomass	75	525	Northern Baja CA, Mexico	75	131	Northern Baja CA, Mexico	840	6,000

The SDG&E system peak demand for 2004 was 4,065 MW. Total energy requirement in the region, include customers served by SDG&E as well as other energy providers, was 20,578 GWh.

The estimated peak demand technical potential of residential and commercial PV in 2010 is 4,400 MW, with an annual energy production of approximately 6,600 GWh. The estimated peak demand technical potential of residential and commercial PV in 2020 is 4,700 MW, with an annual energy production of approximately 7,000 GWh. This PV estimate does not include the technical PV potential of parking areas and parking structures. The technology potential of CSP technology in more rural areas of San Diego County was estimated at 2,900 MW and 5,000 GWh.

Solar trough was the only concentrating solar power (CSP) technology evaluated. There are 354 MW of solar trough CSP plants in operation in California. Dish Stirling, the CSP technology that SDG&E has contracted for in Imperial Valley, was identified as a pre-commercial technology in the report and was not evaluated for that reason.

[1] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region,* August 2005, Executive Summary, p. 5.

Attachment G: California Statewide 2005 Electricity Usage During Peak Periods

Welcome to the California Energy Commission

WWW.ENERGY.CA.GOV / ELECTRICITY / PEAK LOADS

2005 Electricity Usage During Peak Periods

	Megawatts	Percentage of Total
Commercial Sector	**20,907**	**39%**
Air Conditioning	7,690	14%
Cooking	120	0%
Exterior Lighting	63	0%
Hot Water	153	0%
Interior Lighting	6,171	11%
Office Equipment	277	1%
Other	3,489	6%
Refrigeration	978	2%
Space Heating	-	0%
Ventilation	1,967	4%
Residential Sector	**21,765**	**40%**
Air Conditioning	11,154	21%
Cooking	1,187	2%
Dishwasher	331	1%
Domestic Hot Water*	300	1%
Dryer	1,196	2%
Freezer	377	1%
Miscellaneous**	3,568	7%
Pools & Spas***	995	2%
Refrigeration	1,827	3%
Space Heating	-	0%
Television, Video, Satellite	544	1%
Washer	135	0%
Waterbed	153	0%
Industrial Sector	**7,415**	**14%**
Assembly	3,615	7%
Process	2,906	5%
Other	893	2%
Agricultural Sector	**1,959**	**4%**
TCU & Street Lighting	**1,973**	**4%**
Statewide Total	**54,020**	**100%**

* Includes sfamdhw, mfamdhw, soldhw, and soldhwp

** Lighting, fans, electronics

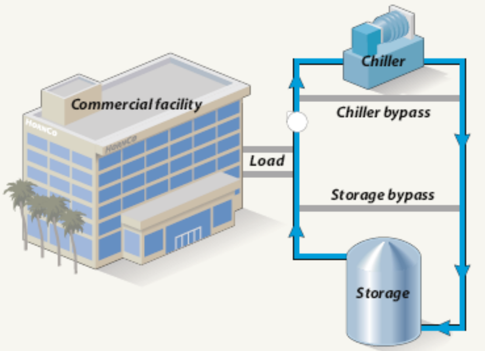
*** Includes pool heat, pool pump, spa heater, spa pump, and solar pool pump

Source: Demand Analysis Office, California Energy Commission

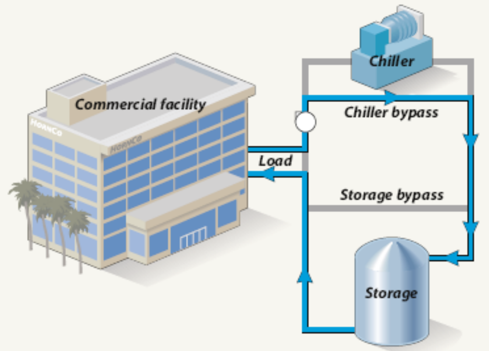
Thermal Energy Storage

Thermal energy storage (TES) systems shift energy usage to a later period to take advantage of cheaper time-based utility rates and/or to reduce overall energy demand. In California, the primary use of thermal energy storage is for cool storage since summer air conditioning is the dominant electric load. Cooling storage mediums of choice are water, ice, and eutectic salts.

Nighttime operation



Daytime operation



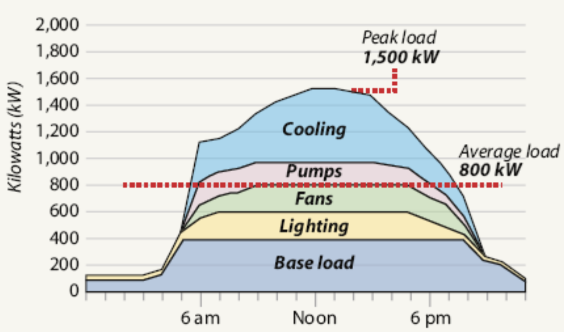
TES systems produce chilled water (or ice) during the night and store for use during the day. This allows central plant equipment to operate at night when energy is readily available, cheaper, and the chiller equipment can run more efficiently. By doing so, buildings can reduce peak demand on the electrical grid and decrease their electrical usage and demand costs.

Benefits of Thermal Energy Storage:

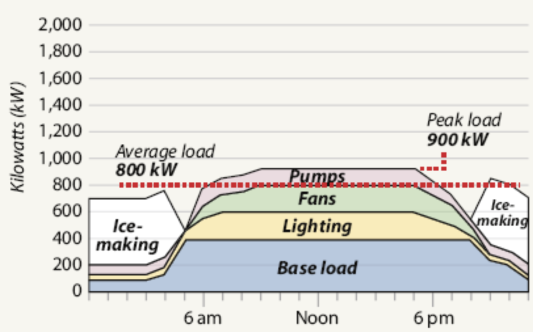
1. Reduce peak demand
2. Decreased electric usage and demand costs.
3. Increased central plant redundancy
4. Reduced emissions from inefficient peaker plants
5. Reduced chiller plant size and corresponding infrastructure

DAILY ELECTRICITY LOAD

Building without Thermal Energy Storage



Building with Thermal Energy Storage



These two graphs show electrical load profiles for similar buildings with and without Thermal Energy Storage. The graph on the left represents a building without TES. The graph on the right represents a building with TES, where all the ice making is done at night, during off-peak hours.

2007 Energy-Efficiency Rebates for Your Home

When shopping for a new appliance or considering a home improvement, think energy efficiency. It helps you save energy for many years to come, and could contribute to lower energy bills at your home. Helping you be more energy-efficient is one of the ways SDG&E® strives to provide exceptional customer service. Here are the rebates SDG&E offers for single family homes.

ENERGY-EFFICIENT MEASURE	YOUR REBATE
Appliances	
Dishwasher ENERGY STAR®-qualified (Energy Factor of 0.65 or greater)	$30/unit
Refrigerator ENERGY STAR®-qualified	$50/unit
Refrigerator (or freezer) recycling, with free pickup	$35/unit
Recycling program run by a 3rd party, not SDG&E. For more on the recycling program call them at 1-800-599-5792.	
Cooling/Heating	
Room Air Conditioner ENERGY STAR®-qualified	$50/unit
Whole House Fan (Must have existing central air conditioning to qualify)	$50/unit
Central Natural Gas Furnace (✣ 92% AFUE)	$200/unit
Insulation	
Attic or Wall Insulation	$0.15/sq. ft.
Swimming Pool	
Pool pump and motor – single speed	$30/unit
Pool pump and motor with automatic controller- multi speed	$100/unit
Time Clock Reset	$25/pool
(Must reduce filtering time by two hours or more and filter during off-peak hours - before noon or after 6PM - daily.)	
Water Heaters *(minimum storage of 30 gallons)*	
Efficient Natural Gas (Energy Factor of 0.62 or greater)	$30/unit
Electric Water Heater (Energy Factor of 0.93 or greater)	$30/unit

Before you buy:

Please review the application for specific requirements and rebate qualifications. Applications for rebates are accepted on a first-come, first-served basis until program funds are no longer available. The amount and availability of rebates may change during the year. Rebates apply only to specific makes and models.

SDG&E and participating retailers are now making it easy for customers to receive rebates instantly. There is no need to fill out an application and wait for a check; instead, the rebate amount is taken off the purchase price at the point of sale. Only one rebate per item - items rebated at the point of sale do not qualify for a mail-in rebate.

Mail-in rebate applications and the list of participating instant rebate retailers are available at *www.sdge.com*. For more information, call the Energy Information Center at **1-800-644-6133** or e-mail *info@sdge.com.* The Energy Information Center is open Monday through Friday, 8am to 5pm.

The Energy Efficiency Rebate Program may be modified or terminated without prior notice. SDG&E is not responsible for any particular contractor selected or equipment/materials installed, or for purchases not meeting applicable qualifications. SDG&E is not responsible for any goods and services obtained by the customer from third parties. This program is funded by California utility customers and administrated by SDG&E, under the auspices of the California Public Utilities Commission.

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Attachment J: San Diego Solar Initiative $1.5 Billion Financing Plan to Achieve 50% GHG Reduction

Overview

The San Diego Solar Initiative financial plan described in this attachment, with a $1.5 billion photovoltaic (PV) incentives budget, results in the installation of 3,004 MW of direct current PV without battery storage. However, as shown on p. J9 titled "PV Installations by Month," there is some degradation in PV performance over time. This results in a net installed direct current PV capacity of 2,941 MW in 2018.

The PV panels generate direct current (DC) electricity. All buildings or residences that receive electricity from the transmission grid use alternating current (AC) electricity. The DC electricity from the PV panels must be converted to alternating current (AC) via an inverter to be compatible with the AC electricity moving over the transmission grid. About a quarter of the potential power is lost in this conversion process.

There are significant losses in converting the DC power from the panels into AC power ready for transmission over the grid. The assumption used in estimating the AC capacity that will be installed under the San Diego Solar Initiative is that only 77 percent of the maximum DC power potential of the panels is converted to AC power. The AC output from 2,941 MW of direct current PV is 0.77 x 2,941 MW = 2,265 MW. The total amount of grid-compatible AC capacity that would be installed under the San Diego Solar Initiative, if no battery storage is included, is 2,265 MW.

PV systems that are equipped with sufficient battery storage can continue to operate at rated capacity during the afternoon peak demand period. This is when electric power is most needed and most valuable. Southern California Edison began a demonstration project using rooftop PV systems as peaking plants in the summer of 2007. These demonstration units use Gaia Power Towers for storage and energy management. Use of Gaia Power Towers adds somewhat less than 10 percent to the gross PV system cost.

A basic assumption of the San Diego Solar Initiative is that all PV installed under the Initiative would be equipped with battery storage to allow this PV capacity to be available to meet afternoon peak demand. Ten (10) percent of the incentives budget is allocated to the purchase of battery storage and associated control hardware instead of PV panels. Therefore the net PV capacity is reduced 10 percent from the 2,265 MW AC figure to allow for all of these PV systems to be equipped with battery storage. The net PV capacity with battery storage is 2,265 MW – (2,265 MW × 0.10) = 2,040 MW.

The San Diego Solar Initiative with a $1.5 billion incentives budget would result in 2,040 MW AC of net rooftop PV with battery storage being added to the generation base in San Diego County.

Total - San Diego Solar Initiative, $1.5 billion incentives budget

1. Solar Electricity Production (MWh)

Initial Year of Operation*	Total Solar Electricity Produced	% of Total MWhs	Large Systems	Small Systems	Residential
2008	1,811	0.0%	1,409	201	201
2009	12,587	0.0%	9,790	1,399	1,399
2010	30,142	0.0%	23,443	3,349	3,349
2011	63,598	0.0%	49,465	7,066	7,066
2012	127,398	0.0%	99,087	14,155	14,155
2013	249,090	0.1%	193,737	27,677	27,677
2014	481,244	0.2%	374,301	53,472	53,472
2015	924,157	0.3%	718,789	102,684	102,684
2016	1,769,200	0.6%	1,376,045	196,578	196,578
2017	3,381,507	1.2%	2,630,061	375,723	375,723
2018	4,312,292	1.5%	3,354,005	479,144	479,144
2019	4,288,355	1.5%	3,335,387	476,484	476,484

INVISIBLE CALCULATIONS - DO NOT MOVE

2. Solar Electric Capacity Installed/Reserved (MW direct current - DC)

Initial Year of Operation*	*New Solar Capacity Installed*	*Cumulative Solar Capacity*	*Large Systems >100 kW*	Small Systems 20-100 kW	Residential <20 kW
2008	*4.3*	*4.3*	3.3	0.5	0.5
2009	*8.1*	*12.4*	6.3	0.9	0.9
2010	*15.5*	*28.0*	12.1	1.7	1.7
2011	*29.6*	*57.6*	23.1	3.3	3.3
2012	*56.6*	*114.2*	44.0	6.3	6.3
2013	*107.9*	*222.1*	84.0	12.0	12.0
2014	*205.9*	*428.1*	160.2	22.9	22.9
2015	*392.9*	*821.0*	305.6	43.7	43.7
2016	*749.7*	*1570.7*	583.1	83.3	83.3
2017	*1430.5*	*3001.2*	1112.6	158.9	158.9
2018	*1.3*	*3002.5*	1.0	0.1	0.1
2019	*1.3*	*3003.8*	1.0	0.1	0.1
Totals:	**3,004**		**2,336**	**334**	**334**

PV Installations (MW DC)

Initial Year of Operation*	Large Systems >100 kW	Small Systems 20-100 kW	Residential <20 kW	Total CA MWhs
2008	3.3	0.5	0.5	255,000,000
2009	6.3	0.9	0.9	257,550,000
2010	12	2	2	260,125,500
2011	23	3	3	262,726,755
2012	44	6	6	265,354,023
2013	84	12	12	268,007,563
2014	160	23	23	270,687,638
2015	306	44	44	273,394,515
2016	583	83	83	276,128,460
2017	1,113	159	159	278,889,745
2018	1	0	0	281,678,642
2019	1	0	0	290,129,001

3. Total Funding Requirement

Initial Year of Operation*	Total Direct Incentives Budget	Admin Costs (3%)	Total Annual Funding Available to Projects	Remaining Funding Rolling Forward	Direct Incentive Sub-Totals: Large Systems	Small Systems	Residential
2008	$5,589,272	$167,678	$4,589,272	$832,322	$1,728,796	$1,300,216	$1,560,259
2009	$10,433,388	$313,002	$9,433,388	$1,544,290	$4,631,146	$2,182,838	$2,619,405
2010	$18,464,795	$553,944	$17,464,795	$2,036,675	$9,465,630	$3,635,984	$4,363,181
2011	$31,479,588	$944,388	$30,479,588	$2,153,387	$17,381,669	$5,953,600	$7,144,320
2012	$52,020,385	$1,560,612	$51,020,385	$1,657,377	$30,053,502	$9,530,401	$11,436,482
2013	$81,837,799	$2,455,134	$80,837,799	$251,965	$48,106,589	$14,877,823	$17,853,388
2014	$124,752,158	$3,742,565	$123,752,158	-$2,483,041	$74,793,540	$22,253,917	$26,704,700
2015	$180,705,960	$5,421,179	$179,705,960	-$6,978,711	$111,301,134	$31,093,103	$37,311,723
2016	$241,731,577	$7,251,947	$240,731,577	-$13,440,020	$155,124,040	$38,912,517	$46,695,020
2017	$285,220,795	$8,556,624	$284,220,795	-$21,399,844	$195,856,976	$40,165,372	$48,198,446
2018	$177,075,093	$5,312,253	$176,075,093	-$26,354,092	$176,075,093	$0	$0
2019	$147,485,792	$4,424,574	$146,485,792	-$30,569,289	$146,485,792	$0	$0
2020	$106,143,713	$3,184,311	$105,143,713	-$33,670,679	$105,143,713	$0	$0
2021	$54,404,769	$1,632,143	$53,404,769	-$35,312,942	$53,404,769	$0	$0
2022	$1,000,000	$30,000	$0	-$35,402,331	$0	$0	$0
2023	$1,000,000	$30,000	$0	-$35,494,401	$0	$0	$0
2024	$1,000,000	$30,000	$0	-$35,589,233	$0	$0	$0
2025	$1,000,000	$30,000	$0	-$35,686,910	$0	$0	$0
2026	$1,000,000	$30,000	$0	-$35,787,517	$0	$0	$0
2027	$1,000,000	$30,000	$0	-$35,891,142	$0	$0	$0
2028	$1,000,000	$30,000	$0	-$35,997,877	$0	$0	$0
Subtotals:	$1,524,345,084	$45,730,353	$1,503,345,084		$1,129,552,390	$169,905,770	$203,886,924
Avg. Annual Totals	$76,217,254	$2,286,518	$75,167,254	100.0%	$56,477,619	$10,194,346	$8,495,289

$1,503,345,084 **TOTAL FUNDING REQUIREMENT (2008-2028)**

*** Reflects actual payment schedule; incentives and rebates will be reserved 6 months to 1 year prior to being paid.**

San Diego Solar Initiative - Residential PV Systems

Avg. Production per kWac-real	1,410	IOU Annual Avg. Rate Increase	0.0%	Assumptions	< 20 kW
In-State Bonus	0%	DC rating to AC-real rating factor	77%	From Other Chart	
Distributed Energy Bonus	0%	IOU Peak Residential Elec. Rate ($/kWh)	0.190		

Initial Year of Operation*	Annual PBI plus rebate expenditures	San Diego Solar Initiative Program - Residential PV Systems <20 kW								
		Solar MWhs annually eligible for PBI Program	ANNUAL SOLAR MWdc Installed	PBI payment per MWh	Customer Bill Savings per kWh	Capital Rebate	Value of Electricity	Tax Credits	Net System Cost	System Cost Decline
				See Data Table on the Right						
2008	$1,560,259	201	0.5			$3.29	$2.84	$2.40	$8.00	
2009	$2,619,405	1,399	0.9			$2.89	$2.84	$2.28	$7.60	5.00%
2010	$4,363,181	3,349	1.7			$2.53	$2.84	$2.17	$7.22	5.00%
2011	$7,144,320	7,066	3.3			$2.17	$2.84	$2.06	$6.86	5.00%
2012	$11,436,482	14,155	6.3			$1.82	$2.84	$1.95	$6.52	5.00%
2013	$17,853,388	27,677	12.0			$1.49	$2.84	$1.86	$6.19	5.00%
2014	$26,704,700	53,472	22.9			$1.17	$2.84	$1.76	$5.88	5.00%
2015	$37,311,723	102,684	43.7			$0.85	$2.84	$1.68	$5.59	5.00%
2016	$46,695,020	196,578	83.3			$0.56	$2.84	$1.59	$5.31	5.00%
2017	$48,198,446	375,723	158.9			$0.30	$2.84	$1.51	$5.04	5.00%
2018	$0	479,144	0.1			$0.00	$2.84	$1.44	$4.79	5.00%
2019	$0	476,484	0.1			$0.00	$2.84	$1.42	$4.74	1.00%
2020	$0	471,719				$0.00	$2.84	$1.41	$4.69	1.00%
2021	$0	467,002				$0.00	$2.84	$1.39	$4.65	1.00%
2022	$0	462,332				$0.00	$2.84	$1.38	$4.60	1.00%
2023	$0	457,708								1.00%
2024	$0	453,131								1.00%
2025	$0	448,600								1%
2026	$0	444,114								1%
2027	$0	439,673								1%
2028	$0									1%
2029	$0									1%
2030	$0									1%
2031	$0									1%
2032	$0									1%
2033	$0									1%
2034	$0									1%
2035	$0									1%
2036	$0									1%
2037	$0									1%
Total for Program	**$203,886,924**	**5,382,211**	**334**		**Average $/Wac-cec =**	$0.61				

*** Reflects actual payment schedule; incentives and rebates will be reserved 6 months to 1 year prior to being paid.**

San Diego Solar Initiative - Small Commercial PV Systems

Avg. Production per kWac-real	1,410	IOU Annual Avg. Rate Increase	0.0%	Assumptions	20 kW to 100 kW
In-State Bonus	0%	DC rating to AC-real rating factor	77%	From Other Chart	
Distributed Energy Bonus	0%	IOU Peak Residential Elec. Rate ($/kWh)	0.190		

		San Diego Solar Initiative Program - Small Commercial PV Systems 20 kW to 100 kW								
Initial Year of Operation*	**Annual PBI plus rebate expenditures**	Solar MWhs produced annually	ANNUAL SOLAR MWdc Installed	PBI payment per MWh	Customer Bill Savings per kWh	Capital Rebate	Value of Electricity	Tax Credits	Net System Cost	System Cost Decline
				See Data Table on the Right						
2008	$1,300,216	201	0.5			$2.74	$2.84	$4.03	$7.00	
2009	$2,182,838	1,399	0.9			$2.41	$2.84	$3.83	$6.65	5.0%
2010	$3,635,984	3,349	1.7			$2.11	$2.84	$3.64	$6.32	5.0%
2011	$5,953,600	7,066	3.3			$1.81	$2.84	$3.46	$6.00	5.0%
2012	$9,530,401	14,155	6.3			$1.52	$2.84	$3.29	$5.70	5.0%
2013	$14,877,823	27,677	12.0			$1.24	$2.84	$3.12	$5.42	5.0%
2014	$22,253,917	53,472	22.9			$0.97	$2.84	$2.97	$5.15	5.0%
2015	$31,093,103	102,684	43.7			$0.71	$2.84	$2.82	$4.89	5.0%
2016	$38,912,517	196,578	83.3			$0.47	$2.84	$2.68	$4.64	5.0%
2017	$40,165,372	375,723	158.9			$0.25	$2.84	$2.54	$4.41	5.0%
2018	$0	479,144	0.1			$0.00	$2.84	$2.42	$4.19	5.0%
2019	$0	476,484	0.1			$0.00	$2.84	$2.39	$4.15	1.0%
2020	$0					$0.00	$2.84	$0.00	$4.11	1.0%
2021	$0					$0.00	$2.84	$0.00	$4.07	1.0%
2022	$0					$0.00	$2.84	$0.00	$4.03	1%
2023	$0								$3.99	1%
2024	$0								$3.95	1%
2025	$0								$3.91	1%
2026	$0								$3.87	1%
2027	$0								$3.83	1%
2028	$0								$3.79	1%
2029	$0								$3.75	1%
2030	$0								$3.71	1%
2031	$0								$3.68	1%
2032	$0								$3.64	1%
2033	$0								$3.60	1%
2034	$0								$3.57	1%
2035	$0								$3.53	1%
2036	$0								$3.50	1%
2037	$0								$3.46	1%
Total for Program	**$169,905,770**	**1,737,931**	**334**		**Average $/Wac-cec =**	$0.51				

*** Reflects actual payment schedule; incentives and rebates will be reserved 6 months to 1 year prior to being paid.**

San Diego Solar Initiative - Large Commercial PV Systems

Year 1 Installation Cost ($/Wdc)	$6.25
Avg. Production per kWac-real	1,889
Performance Degradation	0.60%
AC-cec rating to AC-real rating factor	77%
Blended Avg. IOU Elec. Rate	0.120
Annual Avg. Rate Increase	1.8%

PBI Annual Decline	0%
PBI Pay-out Term (years)	5
In-State Bonus	0%
Distribution Energy Bonus	19%

Federal Tax Rate	35.0%
State Tax Rate	7.8%
Blended Federal & State	40.1%
Discount Rate	7.0%

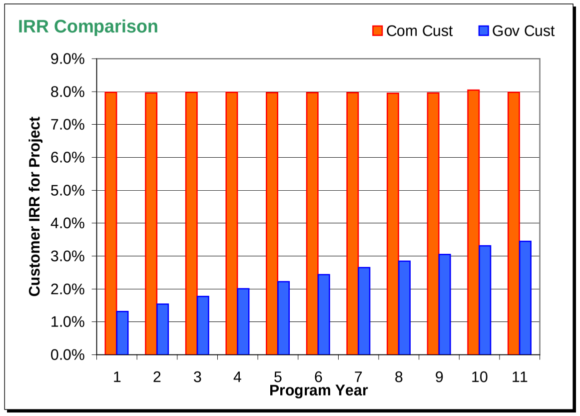
Assumptions > 100 kW
From Other Chart
Recalculate

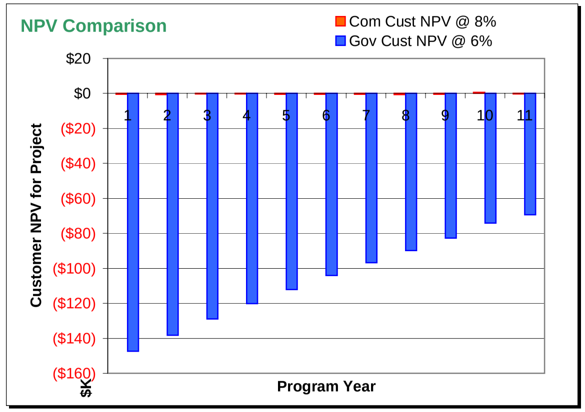
San Diego Solar Initiative Program - Large Commercial PV Systems >100 kW

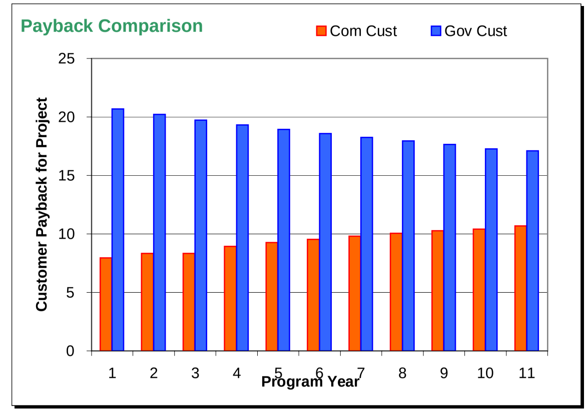
Target IRR: **8.0%**

See Data Table on the Right

Initial Year of Operation*	Annual Encumberance from PBI Program	New Solar MWhs annually eligible for PBI Program	ANNUAL SOLAR MWdc Installed	PBI payment per MWh	Customer Bill Savings per kWh	CBI Equivalent using discount rate	*Fed ITC*	*CA ITC*	Value of Tax Benefits (% of Net Cost)	*Avg Install Price ($/Wdc)*	System Cost Decline	Com IRR	Gov IRR
2008	$1,728,796	1,409	3.3	**358**	0.120	$2.28	**30%**	0%	57.6%	*$6.25*		8.0%	1.3%
2009	$4,631,146	9,790	6.3	315	0.122	$2.01	**30%**	0%	57.6%	*$5.94*	5.0%	8.0%	1.5%
2010	$9,465,630	23,443	12.1	275	0.124	$1.75	**30%**	0%	57.6%	*$5.64*	5.0%	8.0%	1.8%
2011	$17,381,669	49,465	23.1	236	0.127	$1.51	30%	0%	57.6%	*$5.36*	5.0%	8.0%	2.0%
2012	$30,053,502	99,087	44.0	198	0.129	$1.26	30%	0%	57.6%	*$5.09*	5.0%	8.0%	2.2%
2013	$48,106,589	193,737	84.0	162	0.131	$1.03	30%	0%	57.6%	*$4.84*	5.0%	8.0%	2.4%
2014	$74,793,540	374,301	160.2	127	0.134	$0.81	30%	0%	57.6%	*$4.59*	5.0%	8.0%	2.6%
2015	$111,301,134	718,789	305.6	93	0.136	$0.59	30%	0%	57.6%	*$4.36*	5.0%	8.0%	2.8%
2016	$155,124,040	1,376,045	583.1	61	0.138	$0.39	30%	0%	57.6%	*$4.15*	5.0%	8.0%	3.1%
2017	$195,856,976	2,630,061	1112.6	33	0.141	$0.21	30%	0%	57.6%	*$3.94*	5.0%	8.0%	3.3%
2018	$176,075,093	3,354,005	1.0		0.143	$0.00	30%		57.6%	*$3.74*	5.0%	8.0%	3.5%
2019	$146,485,792	3,335,387	1.0		0.146	$0.00	30%		57.6%	*$3.70*	1%	8.3%	3.7%
2020	$105,143,713				0.149	$0.00				*$3.67*	1%		
2021	$53,404,769				0.151	$0.00				*$3.63*	1%		
2022	$0				0.154	$0.00				*$3.59*	1%		
2023	$0				0.157	$0.00				*$3.56*	1%		
2024	$0				0.160	$0.00				*$3.52*	1%		
2025	$0				0.163	$0.00				*$3.49*	1%		
2026	$0				0.165	$0.00				*$3.45*	1%		
2027	$0				0.168	$0.00				*$3.42*	1%		
2028	$0				0.171	$0.00				*$3.38*	1%		
2029	$0				0.175	$0.00				*$3.35*	1%		
2030	$0				0.178	$0.00				*$3.32*	1%		
2031	$0				0.181	$0.00				*$3.28*	1%		
2032	$0				0.184	$0.00				*$3.25*	1%		
2033	$0				0.187					*$3.22*	1%		
2034	$0				0.191					*$3.19*	1%		
2035	$0				0.194					*$3.15*	1%		
2036	$0				0.198					*$3.12*	1%		
2037	$0				0.201					*$3.09*	1%		
Totals for Program	**$1,129,552,390**	**12,165,519**	**2,334**			**Average $/Wac-cec =**	$0.48						







Commercial Customers			
Year	IRR	NPV (8%)	Payback
1	8.0%	($378)	7.9
2	8.0%	($603)	8.3
3	8.0%	($373)	8.3
4	8.0%	($346)	8.9
5	8.0%	($490)	9.3
6	8.0%	($433)	9.5
7	8.0%	($492)	9.8
8	8.0%	($641)	10.1
9	8.0%	($511)	10.3
10	8.0%	$610	10.4
11	8.0%	($354)	10.7
12	8.3%	($354)	10.7

	2008			2009			2010			2011			2012			2013		
	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New
CBI ($/W)		$2.74	$3.29		$2.41	$2.89		$2.11	$2.53		$1.81	$2.17		$1.52	$1.82		$1.24	$1.49
PBI ($/kWh) Y1	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y2	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y3	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y4	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y5	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y6	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y7	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y8	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y9	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y10	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
CBI Equivalent	$ 2.28			$ 2.01			$ 1.75			$ 1.51			$ 1.26			$ 1.03		

Government Customers			
Year	IRR	NPV (6%)	Payback
1	1.3%	($147,451)	20.7
2	1.5%	($138,335)	20.2
3	1.8%	($128,856)	19.7
4	2.0%	($120,146)	19.3
5	2.2%	($112,130)	18.9
6	2.4%	($104,133)	18.6
7	2.6%	($96,693)	18.2
8	2.8%	($89,746)	17.9
9	3.1%	($82,625)	17.6
10	3.3%	($74,060)	17.3
11	3.5%	($69,449)	17.1
12	3.7%	($69,449)	17.1

	2014			2015			2016			2017			2018			2019		
	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New
CBI ($/W)		$0.97	$1.17		$0.71	$0.85		$0.47	$0.56		$0.25	$0.30		$0.00	$0.00		$0.00	$0.00
PBI ($/kWh) Y1	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y2	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y3	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y4	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y5	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y6	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y7	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y8	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y9	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y10	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		

Year 1

Capacity Based Incentive (CBI)	
CBI Rebate Cap:	100%
CBI Rebate ($/W):	
CBI Payee (1=PL, 0=Host)	0

Performance Based Incentive (PBI)	
Y1 PBI ($/kWh)	$0.36
PBI Term (years)	5
Annual Rate of Decline	0%
PBI Payee (1=PL, 0=Host)	0

System Statistics	
System Size (kWaccec):	100
Yr 1 Annual kWh:	145,453
Yr 1 Annual kWh / kWaccec:	1,455
Performance degradation	0.6%
Maintenance Y1-Y25 (% gross cost):	0.30%
Y1 Avoided Cost ($/kWh):	$0.120

Declining PBI	
Year	PBI Schedule
1	0.358
2	0.358
3	0.358
4	0.358
5	0.358
6	0.000
7	0.000
8	0.000
9	0.000
10	0.000
11	0.000
12	0.000
13	0.000
14	0.000
15	0.000
16	0.000
17	0.000
18	0.000
19	0.000
20	0.000
21	0.000
22	0.000
23	0.000
24	0.000
25	0.000

System Costs		
Gross Price ($/W):	$6.25	
Total Gross Price:	$ 625,000	100%
CBI Incentives:	$ -	0%
Net Price	$ 625,000	
% Downpayment:	100%	
Loan Rate (%):	5.0%	
Loan Term (yrs):	10	

Customer Assumptions	
Federal Tax Rate:	35.0%
State Tax Rate:	7.8%
Federal Tax Credit	30.0%
State Tax Credit	0.0%
Com Disc Rate	8%
Gov Disc Rate	6%
Annual Inflation:	0.0%
Elect. Inflation:	1.8%

OutPut		
Total Rebate $	$	257
Total Rebate $	$	1.03
IRR - Private S		8.0%
Payback Com		7.95
IRR - Public Se		1.3%
Payback Gov		20.68

PBI equ value	
payout	$2.57
NPV (5%)	$2.23
npv(10%)	$1.95

Performance Incentive	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance (kWh/year)	3,386,821	145,453	144,583	143,718	142,858	142,003	141,153	140,309	139,469	138,635	137,805	136,980	136,161	135,346	134,536	133,731	132,931	132,136	131,345	130,559	129,778	129,001	128,229	127,462	126,700	125,941
Cumulative Performance		145,453	290,036	433,753	576,611	718,614	859,767	1,000,075	1,139,544	1,278,179	1,415,984	1,552,964	1,689,125	1,824,471	1,959,007	2,092,739	2,225,670	2,357,805	2,489,150	2,619,709	2,749,487	2,878,489	3,006,718	3,134,180	3,260,880	3,386,821
Average Performance to date		145,453	145,018	144,584	144,153	143,723	143,294	142,868	142,443	142,020	141,598	141,179	140,760	140,344	139,929	139,516	139,104	138,694	138,286	137,879	137,474	137,071	136,669	136,269	135,870	135,473
PBI $	257,264	52,072	51,761	51,451	51,143	50,837	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Commercial Customer

Savings:	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance Based Incentive	257,264	52,072	51,761	51,451	51,143	50,837	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Electricity Purchases	504,803	17,454	17,662	17,873	18,085	18,301	18,519	18,739	18,962	19,188	19,417	19,648	19,882	20,119	20,358	20,601	20,846	21,094	21,346	21,600	21,857	22,117	22,381	22,647	22,917	23,190
Total Cost Savings:	762,066	69,527	69,423	69,323	69,228	69,138	18,519	18,739	18,962	19,188	19,417	19,648	19,882	20,119	20,358	20,601	20,846	21,094	21,346	21,600	21,857	22,117	22,381	22,647	22,917	23,190
Expenses:																										
Maintenance	(46,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)
Total Expenses:		(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)
Financing:		$																								
% Downpayment:	100%	625,000																								
% Loan:	0%	0																								
Estimated interest rate on loan (%):	5.0%																									
Term of loan (full yrs):	10																									
Initial Capital Cost (Downpayment)		(625,000)																								
Equipment Loan Principal Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipment Loan Interest Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Financing Cost:	(625,000)	(625,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRE-TAX CASH FLOW, NET*:	90,191	(557,348)	67,548	67,448	67,353	67,263	16,644	16,864	17,087	17,313	17,542	17,773	18,007	18,244	18,483	18,726	18,971	19,219	19,471	19,725	19,982	20,242	20,506	20,772	21,042	21,315
PRE-TAX CASH FLOW, CUMULATIVE:		(557,348)	(489,801)	(422,352)	(354,999)	(287,736)	(271,092)	(254,228)	(237,141)	(219,827)	(202,286)	(184,513)	(166,506)	(148,262)	(129,779)	(111,053)	(92,082)	(72,863)	(53,392)	(33,667)	(13,685)	6,557	27,063	47,835	68,877	90,191
Federal tax calculation (+ = refund)																										
Savings as a result of project	(715,191)	(67,652)	(67,548)	(67,448)	(67,353)	(67,263)	(16,644)	(16,864)	(17,087)	(17,313)	(17,542)	(17,773)	(18,007)	(18,244)	(18,483)	(18,726)	(18,971)	(19,219)	(19,471)	(19,725)	(19,982)	(20,242)	(20,506)	(20,772)	(21,042)	(21,315)
MACRS Accelerated Depr. w/yr 1 bonus (%)		20.0%	32.0%	19.2%	11.5%	11.5%	5.8%																			
Federal Depreciation	531,250	106,250	170,000	102,000	61,094	61,094	30,813	0	0	0	0	0	0	0												
Interest deduction on loan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
State tax deduction	7,035	3,246	1,206	1,198	1,191	1,184	(2,764)	(2,747)	(2,730)	(2,712)	(2,694)	(2,676)	(2,658)	(608)	1,442	1,461	1,480	1,499	1,519	1,539	1,559	1,579	1,599	1,620	1,641	1,663
Annual taxable income	(176,905)	41,844	103,659	35,750	(5,068)	(4,985)	11,405	(19,611)	(19,817)	(20,025)	(20,236)	(20,449)	(20,665)	(18,852)	(17,042)	(17,265)	(17,491)	(17,720)	(17,952)	(18,186)	(18,423)	(18,663)	(18,906)	(19,152)	(19,401)	(19,652)
Taxes due before ITC (+ = refund)	(61,917)	14,645	36,281	12,513	(1,774)	(1,745)	3,992	(6,864)	(6,936)	(7,009)	(7,083)	(7,157)	(7,233)	(6,598)	(5,965)	(6,043)	(6,122)	(6,202)	(6,283)	(6,365)	(6,448)	(6,532)	(6,617)	(6,703)	(6,790)	(6,878)
Federal tax credit (ITC)	187,500	187,500																								
Taxes due after ITC	125,583	202,145	36,281	12,513	(1,774)	(1,745)	3,992	(6,864)	(6,936)	(7,009)	(7,083)	(7,157)	(7,233)	(6,598)	(5,965)	(6,043)	(6,122)	(6,202)	(6,283)	(6,365)	(6,448)	(6,532)	(6,617)	(6,703)	(6,790)	(6,878)
State tax calculation (+ = refund)																										
Savings as a result of project	(715,191)	(67,652)	(67,548)	(67,448)	(67,353)	(67,263)	(16,644)	(16,864)	(17,087)	(17,313)	(17,542)	(17,773)	(18,007)	(18,244)	(18,483)	(18,726)	(18,971)	(19,219)	(19,471)	(19,725)	(19,982)	(20,242)	(20,506)	(20,772)	(21,042)	(21,315)
State Depreciation	625,000	26,042	52,083	52,083	52,083	52,083	52,083	52,083	52,083	52,083	52,083	52,083	52,083	26,042	0											
Interest deduction on loan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual taxable income	(90,191)	(41,610)	(15,464)	(15,365)	(15,270)	(15,179)	35,440	35,219	34,996	34,770	34,542	34,310	34,076	7,798	(18,483)	(18,726)	(18,971)	(19,219)	(19,471)	(19,725)	(19,982)	(20,242)	(20,506)	(20,772)	(21,042)	(21,315)
Taxes due before ITC (+ = refund)	(7,035)	(3,246)	(1,206)	(1,198)	(1,191)	(1,184)	2,764	2,747	2,730	2,712	2,694	2,676	2,658	608	(1,442)	(1,461)	(1,480)	(1,499)	(1,519)	(1,539)	(1,559)	(1,579)	(1,599)	(1,620)	(1,641)	(1,663)
State tax credit (ITC to 200 kW)	0	0																								
Taxes due after ITC	(7,035)	(3,246)	(1,206)	(1,198)	(1,191)	(1,184)	2,764	2,747	2,730	2,712	2,694	2,676	2,658	608	(1,442)	(1,461)	(1,480)	(1,499)	(1,519)	(1,539)	(1,559)	(1,579)	(1,599)	(1,620)	(1,641)	(1,663)
AFTER-TAX CASH FLOW, NET*:	208,740	(358,449)	102,622	78,763	64,388	64,334	23,400	12,747	12,881	13,016	13,153	13,292	13,432	12,254	11,077	11,222	11,369	11,518	11,669	11,821	11,975	12,131	12,289	12,449	12,610	12,774
AFTER-TAX CASH FLOW, CUMULATIVE:		(358,449)	(255,826)	(177,064)	(112,675)	(48,341)	(24,942)	(12,194)	687	13,703	26,856	40,148	53,581	65,834	76,911	88,134	99,503	111,021	122,690	134,511	146,486	158,617	170,906	183,355	195,966	208,740
		(398,337)	117,072	88,904	75,881	65,533	49,075	39,564	36,960	34,675	32,676	13,038	13,420	13,809	14,207	14,613	15,163	15,543	15,978	16,422	16,876	17,339	17,812	18,294	18,787	19,290

8.0%	**Internal Rate of Return**
7.95	**Payback Term**
(378)	**NPV @ 8.0% Discount Rate**

Not For Profit / Government

Savings:	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance Based Incentive	257,264	52,072	51,761	51,451	51,143	50,837	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Electricity Purchases	504,803	17,454	17,662	17,873	18,085	18,301	18,519	18,739	18,962	19,188	19,417	19,648	19,882	20,119	20,358	20,601	20,846	21,094	21,346	21,600	21,857	22,117	22,381	22,647	22,917	23,190
Total Cost Savings:	762,066	69,527	69,423	69,323	69,228	69,138	18,519	18,739	18,962	19,188	19,417	19,648	19,882	20,119	20,358	20,601	20,846	21,094	21,346	21,600	21,857	22,117	22,381	22,647	22,917	23,190
Expenses:																										
Maintenance	(46,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)
Total Expenses:		(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)
Financing:		$																								
% Downpayment:	100%	625,000																								
% Loan:	0%	0																								
Estimated interest rate on loan (%):	5.0%																									
Term of loan (full yrs):	10																									
Initial Capital Cost (Downpayment)		(625,000)																								
Equipment Loan Principal Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipment Loan Interest Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Financing Cost:	(625,000)	(625,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH FLOW, NET*:	90,191	(557,348)	67,548	67,448	67,353	67,263	16,644	16,864	17,087	17,313	17,542	17,773	18,007	18,244	18,483	18,726	18,971	19,219	19,471	19,725	19,982	20,242	20,506	20,772	21,042	21,315
CASH FLOW, CUMULATIVE:		(557,348)	(489,801)	(422,352)	(354,999)	(287,736)	(271,092)	(254,228)	(237,141)	(219,827)	(202,286)	(184,513)	(166,506)	(148,262)	(129,779)	(111,053)	(92,082)	(72,863)	(53,392)	(33,667)	(13,685)	6,557	27,063	47,835	68,877	90,191

1.3%	**Internal Rate of Return**
20.68	**Payback Term**
($147,451)	**NPV @ 6.0% Discount Rate**

Year 10

Capacity Based Incentive (CBI)	
CBI Rebate Cap:	100%
CBI Rebate ($/W):	
CBI Payee (1=PL, 0=Host)	0

Performance Based Incentive (PBI)	
Y1 PBI ($/kWh)	$0.03
PBI Term (years)	5
Annual Rate of Decline	0%
PBI Payee (1=PL, 0=Host)	0

System Statistics	
System Size (kWaccec):	100
Yr 1 Annual kWh:	145,453
Yr 1 Annual kWh / kWaccec:	1,455
Performance degradation	0.6%
Maintenance Y1-Y25 (% gross cost):	0.30%
Y1 Avoided Cost ($/kWh):	$0.141

Declining PBI	
Year	PBI Schedule
1	0.033
2	0.033
3	0.033
4	0.033
5	0.033
6	0.000
7	0.000
8	0.000
9	0.000
10	0.000
11	0.000
12	0.000
13	0.000
14	0.000
15	0.000
16	0.000
17	0.000

System Costs		
Gross Price ($/W):	$3.94	
Total Gross Price:	$ 393,906	100%
CBI Incentives:	$ -	0%
Net Price	$ 393,906	
% Downpayment:	100%	
Loan Rate (%):	5.0%	
Loan Term (yrs):	10	

Customer Assumptions	
Federal Tax Rate:	35.0%
State Tax Rate:	7.8%
Federal Tax Credit	30.0%
State Tax Credit	0.0%
Com Disc Rate	8%
Gov Disc Rate	6%
Annual inflation:	0.0%
Elect. Inflation:	1.8%

Outputs	
Total Rebate $ $	24
Total Rebate $ $	0.09
IRR - Private S	8.0%
Payback Com	10.41
IRR - Public Sc	3.3%
Payback Gov	17.28

PBI equiv. value	
payout	$0.24
NPV (5%)	$0.21
npv(10%)	$0.18

Performance Incentive	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance (kWh/year)	3,386,821	145,453	144,583	143,718	142,858	142,003	141,153	140,309	139,469	138,635	137,805	136,980	136,161	135,346	134,536	133,731	132,931	132,136	131,345	130,559	129,778	129,001	128,229	127,462	126,700	125,941
Cumulative Performance		145,453	290,036	433,753	576,611	718,614	859,767	1,000,075	1,139,544	1,278,179	1,415,984	1,552,964	1,689,125	1,824,471	1,959,007	2,092,739	2,225,670	2,357,805	2,489,150	2,619,709	2,749,487	2,878,489	3,006,718	3,134,180	3,260,880	3,386,821
Average Performance to date		145,453	145,018	144,584	144,153	143,723	143,294	142,868	142,443	142,020	141,598	141,179	140,760	140,344	139,929	139,516	139,104	138,694	138,286	137,879	137,474	137,071	136,669	136,269	135,870	135,473
PBI $	23,714	4,800	4,771	4,743	4,714	4,686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Commercial Customer

Savings:	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance Based Incentive	23,714	4,800	4,771	4,743	4,714	4,686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Electricity Purchases	592,723	20,494	20,738	20,985	21,235	21,488	21,744	22,003	22,265	22,530	22,798	23,070	23,345	23,623	23,904	24,189	24,477	24,768	25,063	25,362	25,664	25,969	26,279	26,592	26,908	27,229
Total Cost Savings:	616,437	25,294	25,510	25,728	25,950	26,174	21,744	22,003	22,265	22,530	22,798	23,070	23,345	23,623	23,904	24,189	24,477	24,768	25,063	25,362	25,664	25,969	26,279	26,592	26,908	27,229
Expenses:																										
Maintenance	(29,543)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)
Total Expenses:		(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)
Financing:		$																								
% Downpayment:	100%	393,906																								
% Loan:	0%	0																								
Estimated interest rate on loan (%):	5.0%																									
Term of loan (full yrs):	10																									
Initial Capital Cost (Downpayment)		(393,906)																								
Equipment Loan Principal Payment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipment Loan Interest Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Financing Cost:	(393,906)	(393,906)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRE-TAX CASH FLOW, NET*:	192,988	(369,793)	24,328	24,546	24,768	24,993	20,562	20,821	21,083	21,348	21,617	21,888	22,163	22,441	22,722	23,007	23,295	23,587	23,882	24,180	24,482	24,788	25,097	25,410	25,727	26,047
PRE-TAX CASH FLOW, CUMULATIVE:		(369,793)	(345,465)	(320,919)	(296,151)	(271,159)	(250,596)	(229,775)	(208,692)	(187,343)	(165,726)	(143,838)	(121,675)	(99,234)	(76,512)	(53,505)	(30,210)	(6,623)	17,258	41,438	65,920	90,708	115,805	141,215	166,941	192,988
Federal tax calculation (+ = refund)																										
Savings as a result of project	(586,894)	(24,113)	(24,328)	(24,546)	(24,768)	(24,993)	(20,562)	(20,821)	(21,083)	(21,348)	(21,617)	(21,888)	(22,163)	(22,441)	(22,722)	(23,007)	(23,295)	(23,587)	(23,882)	(24,180)	(24,482)	(24,788)	(25,097)	(25,410)	(25,727)	(26,047)
MACRS Accelerated Depr. w/yr 1 bonus (%)		20.0%	32.0%	19.2%	11.5%	11.5%	5.8%																			
Federal Depreciation	334,820	66,964	107,142	64,285	38,504	38,504	19,420	0	0	0	0	0	0	0												
Interest deduction on loan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
State tax deduction	15,053	601	(663)	(646)	(628)	(611)	(957)	(936)	(916)	(895)	(874)	(853)	(832)	470	1,772	1,795	1,817	1,840	1,863	1,886	1,910	1,933	1,958	1,982	2,007	2,032
Annual taxable income	(237,020)	43,452	82,152	39,094	13,108	12,901	(2,099)	(21,758)	(21,999)	(22,244)	(22,491)	(22,741)	(22,995)	(21,971)	(20,950)	(21,212)	(21,478)	(21,747)	(22,019)	(22,294)	(22,572)	(22,854)	(23,139)	(23,428)	(23,720)	(24,015)
Taxes due before ITC (+ = refund)	(82,957)	15,208	28,753	13,683	4,588	4,515	(735)	(7,615)	(7,700)	(7,785)	(7,872)	(7,959)	(8,048)	(7,690)	(7,332)	(7,424)	(7,517)	(7,611)	(7,707)	(7,803)	(7,900)	(7,999)	(8,099)	(8,200)	(8,302)	(8,405)
Federal tax credit (ITC)	118,172	118,172																								
Taxes due after ITC	35,215	133,380	28,753	13,683	4,588	4,515	(735)	(7,615)	(7,700)	(7,785)	(7,872)	(7,959)	(8,048)	(7,690)	(7,332)	(7,424)	(7,517)	(7,611)	(7,707)	(7,803)	(7,900)	(7,999)	(8,099)	(8,200)	(8,302)	(8,405)
State tax calculation (+ = refund)																										
Savings as a result of project	(586,894)	(24,113)	(24,328)	(24,546)	(24,768)	(24,993)	(20,562)	(20,821)	(21,083)	(21,348)	(21,617)	(21,888)	(22,163)	(22,441)	(22,722)	(23,007)	(23,295)	(23,587)	(23,882)	(24,180)	(24,482)	(24,788)	(25,097)	(25,410)	(25,727)	(26,047)
State Depreciation	393,906	16,413	32,825	32,825	32,825	32,825	32,825	32,825	32,825	32,825	32,825	32,825	32,825	16,413	0											
Interest deduction on loan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual taxable income	(192,988)	(7,700)	8,498	8,279	8,058	7,833	12,263	12,004	11,742	11,477	11,209	10,937	10,662	(6,028)	(22,722)	(23,007)	(23,295)	(23,587)	(23,882)	(24,180)	(24,482)	(24,788)	(25,097)	(25,410)	(25,727)	(26,047)
Taxes due before ITC (+ = refund)	(15,053)	(601)	663	646	628	611	957	936	916	895	874	853	832	(470)	(1,772)	(1,795)	(1,817)	(1,840)	(1,863)	(1,886)	(1,910)	(1,933)	(1,958)	(1,982)	(2,007)	(2,032)
State tax credit (ITC to 200 kW)	0	0																								
Taxes due after ITC	(15,053)	(601)	663	646	628	611	957	936	916	895	874	853	832	(470)	(1,772)	(1,795)	(1,817)	(1,840)	(1,863)	(1,886)	(1,910)	(1,933)	(1,958)	(1,982)	(2,007)	(2,032)
AFTER-TAX CASH FLOW, NET*:	213,150	(237,014)	53,744	38,875	29,984	30,119	20,784	14,142	14,299	14,458	14,619	14,782	14,947	14,281	13,617	13,788	13,961	14,135	14,312	14,491	14,672	14,855	15,041	15,228	15,418	15,610
AFTER-TAX CASH FLOW, CUMULATIVE:		(237,014)	(183,270)	(144,395)	(114,411)	(84,292)	(63,508)	(49,366)	(35,066)	(20,608)	(5,988)	8,793	23,740	38,021	51,639	65,427	79,387	93,523	107,835	122,326	136,998	151,853	166,894	182,122	197,540	213,150

8.0%	**Internal Rate of Return**
10.41	**Payback Term**
610	**NPV @ 8.0% Discount Rate**

Not For Profit / Government

Savings:	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance Based Incentive	23,714	4,800	4,771	4,743	4,714	4,686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Electricity Purchases	592,723	20,494	20,738	20,985	21,235	21,488	21,744	22,003	22,265	22,530	22,798	23,070	23,345	23,623	23,904	24,189	24,477	24,768	25,063	25,362	25,664	25,969	26,279	26,592	26,908	27,229
Total Cost Savings:	616,437	25,294	25,510	25,728	25,950	26,174	21,744	22,003	22,265	22,530	22,798	23,070	23,345	23,623	23,904	24,189	24,477	24,768	25,063	25,362	25,664	25,969	26,279	26,592	26,908	27,229
Expenses:																										
Maintenance	(29,543)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)
Total Expenses:		(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)
Financing:		$																								
% Downpayment:	100%	393,906																								
% Loan:	0%	0																								
Estimated interest rate on loan (%):	5.0%																									
Term of loan (full yrs):	10																									
Initial Capital Cost (Downpayment)		(393,906)																								
Equipment Loan Principal Payment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipment Loan Interest Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Financing Cost:	(393,906)	(393,906)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH FLOW, NET*:	192,988	(369,793)	24,328	24,546	24,768	24,993	20,562	20,821	21,083	21,348	21,617	21,888	22,163	22,441	22,722	23,007	23,295	23,587	23,882	24,180	24,482	24,788	25,097	25,410	25,727	26,047
CASH FLOW, CUMULATIVE:		(369,793)	(345,465)	(320,919)	(296,151)	(271,159)	(250,596)	(229,775)	(208,692)	(187,343)	(165,726)	(143,838)	(121,675)	(99,234)	(76,512)	(53,505)	(30,210)	(6,623)	17,258	41,438	65,920	90,708	115,805	141,215	166,941	192,988

3.3%	**Internal Rate of Return**
17.28	**Payback Term**
($74,060)	**NPV @ 6.0% Discount Rate**

PV Installations by Month

year	month	Total MW solar installed by month-end	New solar MW DC installed each month	Monthly solar MWh eligible for PBI	Total solar MWh eligible for PBI by year-end
2008	6	0.001		1	
2008	7	0.7	#N/A	86	
2008	8	1.4	0.71	173	
2008	9	2.1	0.71	259	
2008	10	2.8	0.71	345	
2008	11	3.6	0.71	431	
2008	12	4.3	0.71	517	*1811*
2009	1	4.9	0.68	599	
2009	2	5.6	0.68	681	
2009	3	6.3	0.68	763	
2009	4	7.0	0.68	845	
2009	5	7.6	0.68	927	
2009	6	8.3	0.67	1008	
2009	7	9.0	0.67	1090	
2009	8	9.7	0.67	1172	
2009	9	10.3	0.67	1253	
2009	10	11.0	0.67	1335	
2009	11	11.7	0.67	1417	
2009	12	12.4	0.67	1498	*12587*
2010	1	13.6	1.29	1654	
2010	2	14.9	1.29	1811	
2010	3	16.2	1.29	1967	
2010	4	17.5	1.29	2123	
2010	5	18.8	1.29	2279	
2010	6	20.1	1.29	2434	
2010	7	21.4	1.28	2590	
2010	8	22.7	1.28	2746	
2010	9	23.9	1.28	2901	
2010	10	25.2	1.28	3057	
2010	11	26.5	1.28	3212	
2010	12	27.8	1.28	3368	*30142*
2011	1	30.2	2.46	3665	
2011	2	32.7	2.46	3963	
2011	3	35.2	2.45	4261	
2011	4	37.6	2.45	4558	
2011	5	40.1	2.45	4855	
2011	6	42.5	2.45	5152	
2011	7	45.0	2.45	5449	
2011	8	47.4	2.45	5746	
2011	9	49.9	2.45	6043	
2011	10	52.3	2.45	6339	
2011	11	54.7	2.44	6635	
2011	12	57.2	2.44	6932	*63598*
2012	1	61.9	4.69	7499	
2012	2	66.6	4.68	8067	
2012	3	71.2	4.68	8635	
2012	4	75.9	4.68	9202	
2012	5	80.6	4.68	9768	
2012	6	85.3	4.67	10335	
2012	7	89.9	4.67	10901	
2012	8	94.6	4.67	11467	
2012	9	99.3	4.67	12033	
2012	10	103.9	4.66	12598	
2012	11	108.6	4.66	13163	
2012	12	113.3	4.66	13728	*127398*
2013	1	122.2	8.94	14812	
2013	2	131.1	8.93	15895	
2013	3	140.1	8.93	16977	
2013	4	149.0	8.92	18059	
2013	5	157.9	8.92	19140	
2013	6	166.8	8.92	20221	
2013	7	175.7	8.91	21301	
2013	8	184.6	8.91	22380	
2013	9	193.5	8.90	23459	
2013	10	202.4	8.90	24538	
2013	11	211.3	8.89	25616	
2013	12	220.2	8.89	26693	*249090*

Adj.(1) --> 99.95%
to reflect assumed monthly degradation in solar output.

Year of Operation	Solar MWh Generated & Eligible for PBI	*Cumulative MW of solar electricity installations (DC adjusted for degradation)*
2007	1,811	4.3
2008	12,587	12.4
2009	30,142	27.8
2010	63,598	57.2
2011	127,398	113.3
2012	249,090	220.2
2013	481,244	424.3
2014	924,157	813.6
2015	1,769,200	1556.4
2016	3,381,507	2973.7
2017	4,312,292	2957.2
2018	4,288,355	2940.8

2014	1	237.3	17.05	28760	
2014	2	254.3	17.04	30826	
2014	3	271.4	17.03	32891	
2014	4	288.4	17.03	34955	
2014	5	305.4	17.02	37018	
2014	6	322.4	17.01	39079	
2014	7	339.4	17.00	41140	
2014	8	356.4	16.99	43200	
2014	9	373.4	16.98	45258	
2014	10	390.4	16.98	47316	
2014	11	407.3	16.97	49373	
2014	12	424.3	16.96	51428	*481244*
2015	1	456.8	32.53	55371	
2015	2	489.3	32.52	59313	
2015	3	521.8	32.50	63252	
2015	4	554.3	32.48	67190	
2015	5	586.8	32.47	71125	
2015	6	619.2	32.45	75059	
2015	7	651.7	32.44	78990	
2015	8	684.1	32.42	82920	
2015	9	716.5	32.40	86848	
2015	10	748.9	32.39	90773	
2015	11	781.3	32.37	94697	
2015	12	813.6	32.35	98619	*924157*
2016	1	875.7	62.07	106142	
2016	2	937.7	62.04	113662	
2016	3	999.7	62.01	121179	
2016	4	1,061.7	61.98	128691	
2016	5	1,123.7	61.95	136200	
2016	6	1,185.6	61.92	143705	
2016	7	1,247.5	61.89	151206	
2016	8	1,309.3	61.85	158703	
2016	9	1,371.1	61.82	166197	
2016	10	1,432.9	61.79	173687	
2016	11	1,494.7	61.76	181173	
2016	12	1,556.4	61.73	188655	*1769200*
2017	1	1,674.9	118.43	203010	
2017	2	1,793.2	118.37	217358	
2017	3	1,911.5	118.31	231699	
2017	4	2,029.8	118.25	246032	
2017	5	2,148.0	118.19	260359	
2017	6	2,266.1	118.13	274678	
2017	7	2,384.2	118.08	288990	
2017	8	2,502.2	118.02	303295	
2017	9	2,620.2	117.96	317593	
2017	10	2,738.1	117.90	331883	
2017	11	2,855.9	117.84	346166	
2017	12	2,973.7	117.78	360443	*3381507*
2018	1	2,972.3	-1.38	360275	
2018	2	2,970.9	-1.38	360108	
2018	3	2,969.5	-1.38	359941	
2018	4	2,968.2	-1.38	359774	
2018	5	2,966.8	-1.38	359607	
2018	6	2,965.4	-1.38	359441	
2018	7	2,964.0	-1.38	359274	
2018	8	2,962.7	-1.37	359107	
2018	9	2,961.3	-1.37	358941	
2018	10	2,959.9	-1.37	358774	
2018	11	2,958.5	-1.37	358608	
2018	12	2,957.2	-1.37	358441	*4312292*
2019	1	2,955.8	-1.37	358275	
2019	2	2,954.4	-1.37	358109	
2019	3	2,953.1	-1.37	357943	
2019	4	2,951.7	-1.37	357777	
2019	5	2,950.3	-1.37	357611	
2019	6	2,949.0	-1.37	357445	
2019	7	2,947.6	-1.37	357280	
2019	8	2,946.2	-1.37	357114	
2019	9	2,944.9	-1.37	356948	
2019	10	2,943.5	-1.37	356783	
2019	11	2,942.1	-1.36	356617	
2019	12	2,940.8	-1.36	356452	*4288355*

Attachment K: San Diego Solar Initiative Financing Plan Limited to $700 Million Solar Incentives Budget

Overview

The limited San Diego Solar Initiative financial plan described in this attachment, with a $700 million photovoltaic (PV) incentives budget, results in the installation of 1,346 MW of direct current PV without battery storage. However, as shown on p. K9 titled "PV Installations by Month," there is some degradation in PV performance over time. This results in a net installed direct current PV of 1,332 MW in 2018.

The PV panels generate direct current (DC) electricity. All buildings or residences that receive electricity from the transmission grid use alternating current (AC) electricity. The DC electricity from the PV panels must be converted to alternating current (AC) via an inverter to be compatible with the AC electricity moving over the transmission grid. About a quarter of the potential power is lost in this conversion process.

There are significant losses in converting the DC power from the panels into AC power ready for transmission over the grid. The assumption used in estimating the AC capacity that will be installed under the San Diego Solar Initiative is that only 77 percent of the maximum DC power potential of the panels is converted to AC power. The AC output from 1,332 MW of direct current PV is 0.77 x 1,332 MW = 1,026 MW. The total amount of grid-compatible AC capacity that would be installed under the San Diego Solar Initiative, if no battery storage is included, is 1,026 MW.

PV systems that are equipped with sufficient battery storage can continue to operate at rated capacity during the afternoon peak demand period. This is when electric power is most needed and most valuable. Southern California Edison began a demonstration project using rooftop PV systems as peaking plants in the summer of 2007. These demonstration units use Gaia Power Towers for storage and energy management. Use of Gaia Power Towers adds somewhat less than 10 percent to the gross PV system cost.

A basic assumption of the San Diego Solar Initiative is that all PV installed under the Initiative would be equipped with battery storage to allow this PV capacity to be available to meet afternoon peak demand. Ten (10) percent of the incentives budget is allocated to the purchase of battery storage and associated control hardware instead of PV panels. Therefore the net PV capacity is reduced 10 percent from the 1,026 MW AC figure to allow for all of these PV systems to be equipped battery storage. The net PV capacity with battery storage is 1,026 MW – (1,026 MW × 0.10) = 923 MW.

The limited version of the San Diego Solar Initiative with a $700 million incentives budget would result in 923 MW AC of net rooftop PV with battery storage being added to the generation base in San Diego County.

Total - Limited San Diego Solar Initiative, $700 million incentives budget

1. Solar Electricity Production (MWh)

Initial Year of Operation*	Total Solar Electricity Produced	% of Total MWhs	Large Systems	Small Systems	Residential
2008	1,092	0.0%	849	121	121
2009	7,446	0.0%	5,791	827	827
2010	17,390	0.0%	13,526	1,932	1,932
2011	35,665	0.0%	27,740	3,963	3,963
2012	69,269	0.0%	53,876	7,697	7,697
2013	131,079	0.0%	101,951	14,564	14,564
2014	244,788	0.1%	190,391	27,199	27,199
2015	453,991	0.2%	353,104	50,443	50,443
2016	838,903	0.3%	652,480	93,211	93,211
2017	1,547,119	0.6%	1,203,315	171,902	171,902
2018	1,951,706	0.7%	1,517,994	216,856	216,856
2019	1,941,893	0.7%	1,510,361	215,766	215,766

INVISIBLE CALCULATIONS - DO NOT MOVE

2. Solar Electric Capacity Installed/Reserved (MW)

Initial Year of Operation*	*New Solar Capacity Installed*	*Cumulative Solar Capacity*	*Large Systems >100 kW*	Small Systems 20 to 100 kW	Residential <20 kW
2008	*2.6*	*2.6*	2.0	0.3	0.3
2009	*4.7*	*7.3*	3.7	0.5	0.5
2010	*8.7*	*16.0*	6.8	1.0	1.0
2011	*16.0*	*32.0*	12.5	1.8	1.8
2012	*29.5*	*61.5*	22.9	3.3	3.3
2013	*54.2*	*115.7*	42.2	6.0	6.0
2014	*99.8*	*215.5*	77.6	11.1	11.1
2015	*183.6*	*399.1*	142.8	20.4	20.4
2016	*337.8*	*737.0*	262.8	37.5	37.5
2017	*621.6*	*1358.6*	483.5	69.1	69.1
2018	*1.3*	*1359.9*	1.0	0.1	0.1
2019	*1.3*	*1361.2*	1.0	0.1	0.1
Totals:	**1,361**		**1,059**	**151**	**151**

PV Installations (MW)

Initial Year of Operation*	Large Systems >100 kW	Small Systems 20 - 100 kW	Residential <20 kW	Total CA MWhs
2008	2.0	0.3	0.3	255,000,000
2009	3.7	0.5	0.5	257,550,000
2010	7	1	1	260,125,500
2011	12	2	2	262,726,755
2012	23	3	3	265,354,023
2013	42	6	6	268,007,563
2014	78	11	11	270,687,638
2015	143	20	20	273,394,515
2016	263	38	38	276,128,460
2017	483	69	69	278,889,745
2018	1	0	0	281,678,642
2019	1	0	0	290,129,001
	84%	**-6%**	**-6%**	

3. Total Funding Requirement

Initial Year of Operation*	Total Direct Incentives Budget	Admin Costs (3%)	Total Annual Funding Available to Projects	Remaining Funding Rolling Forward	Direct Incentive Sub-Totals: Large Systems	Direct Incentive Sub-Totals: Small Systems	Direct Incentive Sub-Totals: Residential
2008	$3,764,621	$112,939	$2,764,621	$887,061	$1,041,443	$783,263	$939,915
2009	$6,517,350	$195,521	$5,517,350	$1,718,153	$2,727,535	$1,268,098	$1,521,718
2010	$10,917,404	$327,522	$9,917,404	$2,442,175	$5,435,986	$2,037,008	$2,444,410
2011	$17,789,182	$533,675	$16,789,182	$2,981,765	$9,712,778	$3,216,547	$3,859,856
2012	$28,239,033	$847,171	$27,239,033	$3,224,047	$16,314,985	$4,965,476	$5,958,572
2013	$42,658,523	$1,279,756	$41,658,523	$3,041,013	$25,212,865	$7,475,299	$8,970,359
2014	$62,586,294	$1,877,589	$61,586,294	$2,254,654	$37,863,941	$10,782,888	$12,939,466
2015	$87,436,947	$2,623,108	$86,436,947	$699,185	$54,473,411	$14,528,880	$17,434,656
2016	$113,087,272	$3,392,618	$112,087,272	-$1,672,457	$73,511,064	$17,534,640	$21,041,568
2017	$129,515,422	$3,885,463	$128,515,422	-$4,608,094	$90,116,286	$17,454,153	$20,944,984
2018	$81,176,963	$2,435,309	$80,176,963	-$6,181,645	$80,176,963	$0	$0
2019	$66,839,796	$2,005,194	$65,839,796	-$7,372,288	$65,839,796	$0	$0
2020	$47,521,875	$1,425,656	$46,521,875	-$8,019,113	$46,521,875	$0	$0
2021	$24,207,429	$726,223	$23,207,429	-$7,985,910	$23,207,429	$0	$0
2022	$1,000,000	$30,000	$0	-$7,255,487	$0	$0	$0
2023	$1,000,000	$30,000	$0	-$6,503,152	$0	$0	$0
2024	$1,000,000	$30,000	$0	-$5,728,246	$0	$0	$0
2025	$1,000,000	$30,000	$0	-$4,930,093	$0	$0	$0
2026	$1,000,000	$30,000	$0	-$4,107,996	$0	$0	$0
2027	$1,000,000	$30,000	$0	-$3,261,236	$0	$0	$0
2028	$1,000,000	$30,000	$0	-$2,389,073	$0	$0	$0
Subtotals:	$729,258,110	$21,877,743	$708,258,110		$532,156,355	$80,046,252	$96,055,503
Avg. Annual Totals	$36,462,906	$1,093,887	$35,412,906	100.0%	$26,607,818	$4,802,775	$4,002,313

$708,258,110 **TOTAL FUNDING REQUIREMENT (2008-2028)**

*** Reflects actual payment schedule; incentives and rebates will be reserved 6 months to 1 year prior to being paid.**

San Diego Solar Initiative - Residential PV Systems

Avg. Production per kWac-real	1,410	IOU Annual Avg. Rate Increase	0.0%	Assumptions	<20 kW
In-State Bonus	0%	DC rating to AC-real rating factor	77%	From Other Chart	
Distributed Energy Bonus	0%	IOU Peak Residential Elec. Rate ($/kWh)	0.190		

Initial Year of Operation*	Annual PBI plus rebate expenditures	San Diego Solar Initiative Program - Residential PV Systems <20 kW								
		Solar MWhs annually eligible for PBI Program	ANNUAL SOLAR MWdc Installed	PBI payment per MWh	Customer Bill Savings per kWh	Capital Rebate	Value of Electricity	Tax Credits	Net System Cost	System Cost Decline
				See Data Table on the Right						
2008	$939,915	121	0.3			$3.29	$2.84	$2.40	$8.00	
2009	$1,521,718	827	0.5			$2.89	$2.84	$2.28	$7.60	5.00%
2010	$2,444,410	1,932	1.0			$2.53	$2.84	$2.17	$7.22	5.00%
2011	$3,859,856	3,963	1.8			$2.17	$2.84	$2.06	$6.86	5.00%
2012	$5,958,572	7,697	3.3			$1.82	$2.84	$1.95	$6.52	5.00%
2013	$8,970,359	14,564	6.0			$1.49	$2.84	$1.86	$6.19	5.00%
2014	$12,939,466	27,199	11.1			$1.17	$2.84	$1.76	$5.88	5.00%
2015	$17,434,656	50,443	20.4			$0.85	$2.84	$1.68	$5.59	5.00%
2016	$21,041,568	93,211	37.5			$0.56	$2.84	$1.59	$5.31	5.00%
2017	$20,944,984	171,902	69.1			$0.30	$2.84	$1.51	$5.04	5.00%
2018	$0	216,856	0.1			$0.00	$2.84	$1.44	$4.79	5.00%
2019	$0	215,766	0.1			$0.00	$2.84	$1.42	$4.74	1.00%
2020	$0	213,608				$0.00	$2.84	$1.41	$4.69	1.00%
2021	$0	211,472				$0.00	$2.84	$1.39	$4.65	1.00%
2022	$0	209,357				$0.00	$2.84	$1.38	$4.60	1.00%
2023	$0	207,264								1.00%
2024	$0	205,191								1.00%
2025	$0	203,139								1%
2026	$0	201,108								1%
2027	$0	199,097								1%
2028	$0									1%
2029	$0									1%
2030	$0									1%
2031	$0									1%
2032	$0									1%
2033	$0									1%
2034	$0									1%
2035	$0									1%
2036	$0									1%
2037	$0									1%
Total for Program	**$96,055,503**	**2,454,719**	**151**		**Average $/Wac-cec =**	$0.64				

*** Reflects actual payment schedule; incentives and rebates will be reserved 6 months to 1 year prior to being paid.**

San Diego Solar Initiative - Small Commercial PV Systems

Avg. Production per kWac-real	1,410	IOU Annual Avg. Rate Increase	0.0%	Assumptions	20 - 100 kW
In-State Bonus	0%	DC rating to AC-real rating factor	77%	From Other Chart	
Distributed Energy Bonus	0%	IOU Peak Residential Elec. Rate ($/kWh)	0.190		

San Diego Solar Initiative Program - Small Commercial PV Systems 20 to 100 kW

Initial Year of Operation*	**Annual PBI plus rebate expenditures**	Solar MWhs produced annually	ANNUAL SOLAR MWdc Installed	PBI payment per MWh	Customer Bill Savings per kWh	Capital Rebate	Value of Electricity	Tax Credits	Net System Cost	System Cost Decline
				See Data Table on the Right						
2008	$783,263	121	0.3			$2.74	$2.84	$4.03	$7.00	
2009	$1,268,098	827	0.5			$2.41	$2.84	$3.83	$6.65	5.0%
2010	$2,037,008	1,932	1.0			$2.11	$2.84	$3.64	$6.32	5.0%
2011	$3,216,547	3,963	1.8			$1.81	$2.84	$3.46	$6.00	5.0%
2012	$4,965,476	7,697	3.3			$1.52	$2.84	$3.29	$5.70	5.0%
2013	$7,475,299	14,564	6.0			$1.24	$2.84	$3.12	$5.42	5.0%
2014	$10,782,888	27,199	11.1			$0.97	$2.84	$2.97	$5.15	5.0%
2015	$14,528,880	50,443	20.4			$0.71	$2.84	$2.82	$4.89	5.0%
2016	$17,534,640	93,211	37.5			$0.47	$2.84	$2.68	$4.64	5.0%
2017	$17,454,153	171,902	69.1			$0.25	$2.84	$2.54	$4.41	5.0%
2018	$0	216,856	0.1			$0.00	$2.84	$2.42	$4.19	5.0%
2019	$0	215,766	0.1			$0.00	$2.84	$2.39	$4.15	1.0%
2020	$0					$0.00	$2.84	$0.00	$4.11	1.0%
2021	$0					$0.00	$2.84	$0.00	$4.07	1.0%
2022	$0					$0.00	$2.84	$0.00	$4.03	1%
2023	$0								$3.99	1%
2024	$0								$3.95	1%
2025	$0								$3.91	1%
2026	$0								$3.87	1%
2027	$0								$3.83	1%
2028	$0								$3.79	1%
2029	$0								$3.75	1%
2030	$0								$3.71	1%
2031	$0								$3.68	1%
2032	$0								$3.64	1%
2033	$0								$3.60	1%
2034	$0								$3.57	1%
2035	$0								$3.53	1%
2036	$0								$3.50	1%
2037	$0								$3.46	1%
Total for Program	**$80,046,252**	**804,483**	**151**		**Average $/Wac-cec =**	$0.53				

*** Reflects actual payment schedule; incentives and rebates will be reserved 6 months to 1 year prior to being paid.**

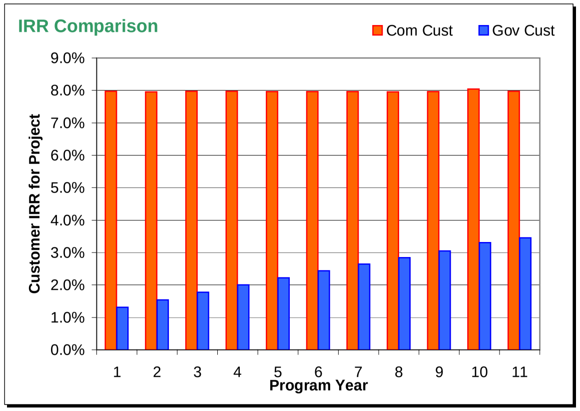
San Diego Solar Initiative - Large Commercial PV Systems

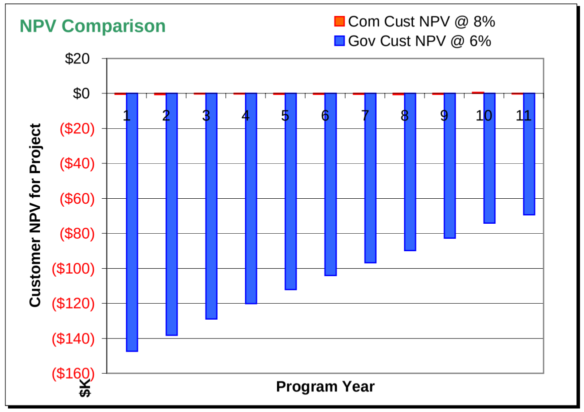
Year 1 Installation Cost ($/Wdc)	$6.25	PBI Annual Decline	0%	Federal Tax Rate	35.0%		
Avg. Production per kWac-real	1,889	PBI Pay-out Term (years)	5	State Tax Rate	7.8%	Assumptions	>100 kW
Performance Degradation	0.60%	In-State Bonus	0%	Blended Federal & State	40.1%	From Other Chart	
AC-cec rating to AC-real rating factor	77%	Distribution Energy Bonus	19%	Discount Rate	7.0%	Recalculate	
Blended Avg. IOU Elec. Rate	0.120						
Annual Avg. Rate Increase	1.8%						

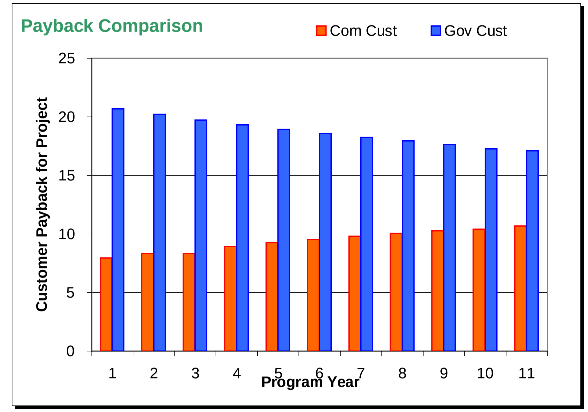
San Diego Solar Initiative Program - Large Commercial PV Systems >100 kW

Target IRR: 8.0%

Initial Year of Operation*	Annual Encumberance from PBI Program	New Solar MWhs annually eligible for PBI Program	ANNUAL SOLAR MWdc Installed	PBI payment per MWh	Customer Bill Savings per kWh	CBI Equivalent using discount rate	*Fed ITC*	*CA ITC*	Value of Tax Benefits (% of Net Cost)	*Avg Install Price ($/Wdc)*	System Cost Decline	Com IRR	Gov IRR
				See Data Table on the Right									
2008	$1,041,443	849	2.0	**358**	0.120	$2.28	**30%**	0%	57.6%	*$6.25*		8.0%	1.3%
2009	$2,727,535	5,791	3.7	315	0.122	$2.01	**30%**	0%	57.6%	*$5.94*	5.0%	8.0%	1.5%
2010	$5,435,986	13,526	6.8	275	0.124	$1.75	**30%**	0%	57.6%	*$5.64*	5.0%	8.0%	1.8%
2011	$9,712,778	27,740	12.5	236	0.127	$1.51	30%	0%	57.6%	*$5.36*	5.0%	8.0%	2.0%
2012	$16,314,985	53,876	22.9	198	0.129	$1.26	30%	0%	57.6%	*$5.09*	5.0%	8.0%	2.2%
2013	$25,212,865	101,951	42.2	162	0.131	$1.03	30%	0%	57.6%	*$4.84*	5.0%	8.0%	2.4%
2014	$37,863,941	190,391	77.6	127	0.134	$0.81	30%	0%	57.6%	*$4.59*	5.0%	8.0%	2.6%
2015	$54,473,411	353,104	142.8	93	0.136	$0.59	30%	0%	57.6%	*$4.36*	5.0%	8.0%	2.8%
2016	$73,511,064	652,480	262.8	61	0.138	$0.39	30%	0%	57.6%	*$4.15*	5.0%	8.0%	3.1%
2017	$90,116,286	1,203,315	483.5	33	0.141	$0.21	30%	0%	57.6%	*$3.94*	5.0%	8.0%	3.3%
2018	$80,176,963	1,517,994	1.0		0.143	$0.00	30%		57.6%	*$3.74*	5.0%	8.0%	3.5%
2019	$65,839,796	1,510,361	1.0		0.146	$0.00	30%		57.6%	*$3.70*	1%	8.3%	3.7%
2020	$46,521,875				0.149	$0.00				*$3.67*	1%		
2021	$23,207,429				0.151	$0.00				*$3.63*	1%		
2022	$0				0.154	$0.00				*$3.59*	1%		
2023	$0				0.157	$0.00				*$3.56*	1%		
2024	$0				0.160	$0.00				*$3.52*	1%		
2025	$0				0.163	$0.00				*$3.49*	1%		
2026	$0				0.165	$0.00				*$3.45*	1%		
2027	$0				0.168	$0.00				*$3.42*	1%		
2028	$0				0.171	$0.00				*$3.38*	1%		
2029	$0				0.175	$0.00				*$3.35*	1%		
2030	$0				0.178	$0.00				*$3.32*	1%		
2031	$0				0.181	$0.00				*$3.28*	1%		
2032	$0				0.184	$0.00				*$3.25*	1%		
2033	$0				0.187					*$3.22*	1%		
2034	$0				0.191					*$3.19*	1%		
2035	$0				0.194					*$3.15*	1%		
2036	$0				0.198					*$3.12*	1%		
2037	$0				0.201					*$3.09*	1%		
Totals for Program	**$532,156,355**	**5,631,378**	**1,057**			**Average $/Wac-cec =**	$0.50						







Commercial Customers			
Year	IRR	NPV (8%)	Payback
1	8.0%	($378)	7.9
2	8.0%	($603)	8.3
3	8.0%	($373)	8.3
4	8.0%	($346)	8.9
5	8.0%	($490)	9.3
6	8.0%	($433)	9.5
7	8.0%	($492)	9.8
8	8.0%	($641)	10.1
9	8.0%	($511)	10.3
10	8.0%	$610	10.4
11	8.0%	($354)	10.7
12	8.3%	($354)	10.7

	2008			2009			2010			2011			2012			2013		
	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New
CBI ($/W)		$2.74	$3.29		$2.41	$2.89		$2.11	$2.53		$1.81	$2.17		$1.52	$1.82		$1.24	$1.49
PBI ($/kWh) Y1	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y2	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y3	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y4	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y5	$0.36			$0.32			$0.28			$0.24			$0.20			$0.16		
Y6	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y7	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y8	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y9	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y10	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
CBI Equivalent	$ 2.28			$ 2.01			$ 1.75			$ 1.51			$ 1.26			$ 1.03		

Government Customers			
Year	IRR	NPV (6%)	Payback
1	1.3%	($147,451)	20.7
2	1.5%	($138,335)	20.2
3	1.8%	($128,856)	19.7
4	2.0%	($120,146)	19.3
5	2.2%	($112,130)	18.9
6	2.4%	($104,133)	18.6
7	2.6%	($96,693)	18.2
8	2.8%	($89,746)	17.9
9	3.1%	($82,625)	17.6
10	3.3%	($74,060)	17.3
11	3.5%	($69,449)	17.1
12	3.7%	($69,449)	17.1

	2014			2015			2016			2017			2018			2019		
	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New	Com	Res Retro	Res New
CBI ($/W)		$0.97	$1.17		$0.71	$0.85		$0.47	$0.56		$0.25	$0.30		$0.00	$0.00		$0.00	$0.00
PBI ($/kWh) Y1	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y2	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y3	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y4	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y5	$0.13			$0.09			$0.06			$0.03			$0.00			$0.00		
Y6	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y7	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y8	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y9	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		
Y10	$0.00			$0.00			$0.00			$0.00			$0.00			$0.00		

Capacity Based Incentive (CBI)	
CBI Rebate Cap:	100%
CBI Rebate ($/W):	
CBI Payee (1=PL, 0=Host)	0

Performance Based Incentive (PBI)	
Y1 PBI ($/kWh)	$0.36
PBI Term (years)	5
Annual Rate of Decline	0%
PBI Payee (1=PL, 0=Host)	0

System Statistics	
System Size (kWaccec):	100
Yr 1 Annual kWh:	145,453
Yr 1 Annual kWh / kWaccec:	1,455
Performance degradation	0.6%
Maintenance Y1-Y25 (% gross cost):	0.30%
Y1 Avoided Cost ($/kWh):	$0.120

Declining PBI	
Year	PBI Schedule
1	0.358
2	0.358
3	0.358
4	0.358
5	0.358
6	0.000
7	0.000
8	0.000
9	0.000
10	0.000
11	0.000
12	0.000
13	0.000
14	0.000
15	0.000
16	0.000
17	0.000
18	0.000
19	0.000
20	0.000
21	0.000
22	0.000
23	0.000
24	0.000
25	0.000

System Costs		
Gross Price ($/W):	$6.25	
Total Gross Price:	$ 625,000	100%
CBI Incentives:	$ -	0%
Net Price	$ 625,000	
% Downpayment:	100%	
Loan Rate (%):	5.0%	
Loan Term (yrs):	10	

Customer Assumptions	
Federal Tax Rate:	35.0%
State Tax Rate:	7.8%
Federal Tax Credit	30.0%
State Tax Credit	0.0%
Com Disc Rate	8%
Gov Disc Rate	6%
Annual Inflation:	0.0%
Elect. Inflation:	1.8%

OutPut		
Total Rebate $/	$	257
Total Rebate $/	$	1.03
IRR - Private S		8.0%
Payback Com		7.95
IRR - Public Se		1.3%
Payback Gov		20.68

PBI equ value	
payout	$2.57
NPV (5%)	$2.23
npv(10%)	$1.95

Year 1

Performance Incentive	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance (kWh/year)	3,386,821	145,453	144,583	143,718	142,858	142,003	141,153	140,309	139,469	138,635	137,805	136,980	136,161	135,346	134,536	133,731	132,931	132,136	131,345	130,559	129,778	129,001	128,229	127,462	126,700	125,941
Cumulative Performance		145,453	290,036	433,753	576,611	718,614	859,767	1,000,075	1,139,544	1,278,179	1,415,984	1,552,964	1,689,125	1,824,471	1,959,007	2,092,739	2,225,670	2,357,805	2,489,150	2,619,709	2,749,487	2,878,489	3,006,718	3,134,180	3,260,880	3,386,821
Average Performance to date		145,453	145,018	144,584	144,153	143,723	143,294	142,868	142,443	142,020	141,598	141,179	140,760	140,344	139,929	139,516	139,104	138,694	138,286	137,879	137,474	137,071	136,669	136,269	135,870	135,473
PBI $	257,264	52,072	51,761	51,451	51,143	50,837	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Commercial Customer

Savings:	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance Based Incentive	257,264	52,072	51,761	51,451	51,143	50,837	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Electricity Purchases	504,803	17,454	17,662	17,873	18,085	18,301	18,519	18,739	18,962	19,188	19,417	19,648	19,882	20,119	20,358	20,601	20,846	21,094	21,346	21,600	21,857	22,117	22,381	22,647	22,917	23,190
Total Cost Savings:	762,066	69,527	69,423	69,323	69,228	69,138	18,519	18,739	18,962	19,188	19,417	19,648	19,882	20,119	20,358	20,601	20,846	21,094	21,346	21,600	21,857	22,117	22,381	22,647	22,917	23,190
Expenses:																										
Maintenance	(46,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)
Total Expenses:		(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)
Financing:		$																								
% Downpayment:	100%	625,000																								
% Loan:	0%	0																								
Estimated interest rate on loan (%):	5.0%																									
Term of loan (full yrs):	10																									
Initial Capital Cost (Downpayment)		(625,000)																								
Equipment Loan Principal Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipment Loan Interest Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Financing Cost:	(625,000)	(625,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRE-TAX CASH FLOW, NET*:	90,191	(557,348)	67,548	67,448	67,353	67,263	16,644	16,864	17,087	17,313	17,542	17,773	18,007	18,244	18,483	18,726	18,971	19,219	19,471	19,725	19,982	20,242	20,506	20,772	21,042	21,315
PRE-TAX CASH FLOW, CUMULATIVE:		(557,348)	(489,801)	(422,352)	(354,999)	(287,736)	(271,092)	(254,228)	(237,141)	(219,827)	(202,286)	(184,513)	(166,506)	(148,262)	(129,779)	(111,053)	(92,082)	(72,863)	(53,392)	(33,667)	(13,685)	6,557	27,063	47,835	68,877	90,191
Federal tax calculation (+ = refund)																										
Savings as a result of project	(715,191)	(67,652)	(67,548)	(67,448)	(67,353)	(67,263)	(16,644)	(16,864)	(17,087)	(17,313)	(17,542)	(17,773)	(18,007)	(18,244)	(18,483)	(18,726)	(18,971)	(19,219)	(19,471)	(19,725)	(19,982)	(20,242)	(20,506)	(20,772)	(21,042)	(21,315)
MACRS Accelerated Depr. w/yr 1 bonus (%)		20.0%	32.0%	19.2%	11.5%	11.5%	5.8%																			
Federal Depreciation	531,250	106,250	170,000	102,000	61,094	61,094	30,813	0	0	0	0	0	0	0												
Interest deduction on loan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
State tax deduction	7,035	3,246	1,206	1,198	1,191	1,184	(2,764)	(2,747)	(2,730)	(2,712)	(2,694)	(2,676)	(2,658)	(608)	1,442	1,461	1,480	1,499	1,519	1,539	1,559	1,579	1,599	1,620	1,641	1,663
Annual taxable income	(176,905)	41,844	103,659	35,750	(5,068)	(4,985)	11,405	(19,611)	(19,817)	(20,025)	(20,236)	(20,449)	(20,665)	(18,852)	(17,042)	(17,265)	(17,491)	(17,720)	(17,952)	(18,186)	(18,423)	(18,663)	(18,906)	(19,152)	(19,401)	(19,652)
Taxes due before ITC (+ = refund)	(61,917)	14,645	36,281	12,513	(1,774)	(1,745)	3,992	(6,864)	(6,936)	(7,009)	(7,083)	(7,157)	(7,233)	(6,598)	(5,965)	(6,043)	(6,122)	(6,202)	(6,283)	(6,365)	(6,448)	(6,532)	(6,617)	(6,703)	(6,790)	(6,878)
Federal tax credit (ITC)	187,500	187,500																								
Taxes due after ITC	125,583	202,145	36,281	12,513	(1,774)	(1,745)	3,992	(6,864)	(6,936)	(7,009)	(7,083)	(7,157)	(7,233)	(6,598)	(5,965)	(6,043)	(6,122)	(6,202)	(6,283)	(6,365)	(6,448)	(6,532)	(6,617)	(6,703)	(6,790)	(6,878)
State tax calculation (+ = refund)																										
Savings as a result of project	(715,191)	(67,652)	(67,548)	(67,448)	(67,353)	(67,263)	(16,644)	(16,864)	(17,087)	(17,313)	(17,542)	(17,773)	(18,007)	(18,244)	(18,483)	(18,726)	(18,971)	(19,219)	(19,471)	(19,725)	(19,982)	(20,242)	(20,506)	(20,772)	(21,042)	(21,315)
State Depreciation	625,000	26,042	52,083	52,083	52,083	52,083	52,083	52,083	52,083	52,083	52,083	52,083	52,083	26,042	0											
Interest deduction on loan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual taxable income	(90,191)	(41,610)	(15,464)	(15,365)	(15,270)	(15,179)	35,440	35,219	34,996	34,770	34,542	34,310	34,076	7,798	(18,483)	(18,726)	(18,971)	(19,219)	(19,471)	(19,725)	(19,982)	(20,242)	(20,506)	(20,772)	(21,042)	(21,315)
Taxes due before ITC (+ = refund)	(7,035)	(3,246)	(1,206)	(1,198)	(1,191)	(1,184)	2,764	2,747	2,730	2,712	2,694	2,676	2,658	608	(1,442)	(1,461)	(1,480)	(1,499)	(1,519)	(1,539)	(1,559)	(1,579)	(1,599)	(1,620)	(1,641)	(1,663)
State tax credit (ITC to 200 kW)	0	0																								
Taxes due after ITC	(7,035)	(3,246)	(1,206)	(1,198)	(1,191)	(1,184)	2,764	2,747	2,730	2,712	2,694	2,676	2,658	608	(1,442)	(1,461)	(1,480)	(1,499)	(1,519)	(1,539)	(1,559)	(1,579)	(1,599)	(1,620)	(1,641)	(1,663)
AFTER-TAX CASH FLOW, NET*:	208,740	(358,449)	102,622	78,763	64,388	64,334	23,400	12,747	12,881	13,016	13,153	13,292	13,432	12,254	11,077	11,222	11,369	11,518	11,669	11,821	11,975	12,131	12,289	12,449	12,610	12,774
AFTER-TAX CASH FLOW, CUMULATIVE:		(358,449)	(255,826)	(177,064)	(112,675)	(48,341)	(24,942)	(12,194)	687	13,703	26,856	40,148	53,581	65,834	76,911	88,134	99,503	111,021	122,690	134,511	146,486	158,617	170,906	183,355	195,966	208,740
		(398,337)	117,072	88,904	75,881	65,533	49,075	39,564	36,960	34,675	32,676	13,038	13,420	13,809	14,207	14,613	15,163	15,543	15,978	16,422	16,876	17,339	17,812	18,294	18,787	19,290

8.0%	**Internal Rate of Return**
7.95	**Payback Term**
(378)	**NPV @ 8.0% Discount Rate**

Not For Profit / Government

Savings:	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance Based Incentive	257,264	52,072	51,761	51,451	51,143	50,837	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Electricity Purchases	504,803	17,454	17,662	17,873	18,085	18,301	18,519	18,739	18,962	19,188	19,417	19,648	19,882	20,119	20,358	20,601	20,846	21,094	21,346	21,600	21,857	22,117	22,381	22,647	22,917	23,190
Total Cost Savings:	762,066	69,527	69,423	69,323	69,228	69,138	18,519	18,739	18,962	19,188	19,417	19,648	19,882	20,119	20,358	20,601	20,846	21,094	21,346	21,600	21,857	22,117	22,381	22,647	22,917	23,190
Expenses:																										
Maintenance	(46,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)
Total Expenses:		(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)	(1,875)
Financing:		$																								
% Downpayment:	100%	625,000																								
% Loan:	0%	0																								
Estimated interest rate on loan (%):	5.0%																									
Term of loan (full yrs):	10																									
Initial Capital Cost (Downpayment)		(625,000)																								
Equipment Loan Principal Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipment Loan Interest Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Financing Cost:	(625,000)	(625,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH FLOW, NET*:	90,191	(557,348)	67,548	67,448	67,353	67,263	16,644	16,864	17,087	17,313	17,542	17,773	18,007	18,244	18,483	18,726	18,971	19,219	19,471	19,725	19,982	20,242	20,506	20,772	21,042	21,315
CASH FLOW, CUMULATIVE:		(557,348)	(489,801)	(422,352)	(354,999)	(287,736)	(271,092)	(254,228)	(237,141)	(219,827)	(202,286)	(184,513)	(166,506)	(148,262)	(129,779)	(111,053)	(92,082)	(72,863)	(53,392)	(33,667)	(13,685)	6,557	27,063	47,835	68,877	90,191

1.3%	**Internal Rate of Return**
20.68	**Payback Term**
($147,451)	**NPV @ 6.0% Discount Rate**

Year 10

Capacity Based Incentive (CBI)	
CBI Rebate Cap:	100%
CBI Rebate ($/W):	
CBI Payee (1=PL, 0=Host)	0

Performance Based Incentive (PBI)	
Y1 PBI ($/kWh)	$0.03
PBI Term (years)	5
Annual Rate of Decline	0%
PBI Payee (1=PL, 0=Host)	0

System Statistics	
System Size (kWaccec):	100
Yr 1 Annual kWh:	145,453
Yr 1 Annual kWh / kWaccec:	1,455
Performance degradation	0.6%
Maintenance Y1-Y25 (% gross cost):	0.30%
Y1 Avoided Cost ($/kWh):	$0.141

Declining PBI	
Year	PBI Schedule
1	0.033
2	0.033
3	0.033
4	0.033
5	0.033
6	0.000
7	0.000
8	0.000
9	0.000
10	0.000
11	0.000
12	0.000
13	0.000
14	0.000
15	0.000
16	0.000
17	0.000

System Costs		
Gross Price ($/W):	$3.94	
Total Gross Price:	$ 393,906	100%
CBI Incentives:	$ -	0%
Net Price	$ 393,906	
% Downpayment:	100%	
Loan Rate (%):	5.0%	
Loan Term (yrs):	10	

Customer Assumptions	
Federal Tax Rate:	35.0%
State Tax Rate:	7.8%
Federal Tax Credit	30.0%
State Tax Credit	0.0%
Com Disc Rate	8%
Gov Disc Rate	6%
Annual inflation:	0.0%
Elect. Inflation:	1.8%

Outputs	
Total Rebate $ $	24
Total Rebate $ $	0.09
IRR - Private S	8.0%
Payback Com	10.41
IRR - Public Se	3.3%
Payback Gov	17.28

PBI equiv. value	
payout	$0.24
NPV (5%)	$0.21
npv(10%)	$0.18

Performance Incentive	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance (kWh/year)	3,386,821	145,453	144,583	143,718	142,858	142,003	141,153	140,309	139,469	138,635	137,805	136,980	136,161	135,346	134,536	133,731	132,931	132,136	131,345	130,559	129,778	129,001	128,229	127,462	126,700	125,941
Cumulative Performance		145,453	290,036	433,753	576,611	718,614	859,767	1,000,075	1,139,544	1,278,179	1,415,984	1,552,964	1,689,125	1,824,471	1,959,007	2,092,739	2,225,670	2,357,805	2,489,150	2,619,709	2,749,487	2,878,489	3,006,718	3,134,180	3,260,880	3,386,821
Average Performance to date		145,453	145,018	144,584	144,153	143,723	143,294	142,868	142,443	142,020	141,598	141,179	140,760	140,344	139,929	139,516	139,104	138,694	138,286	137,879	137,474	137,071	136,669	136,269	135,870	135,473
PBI $	23,714	4,800	4,771	4,743	4,714	4,686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Commercial Customer

Savings:	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance Based Incentive	23,714	4,800	4,771	4,743	4,714	4,686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Electricity Purchases	592,723	20,494	20,738	20,985	21,235	21,488	21,744	22,003	22,265	22,530	22,798	23,070	23,345	23,623	23,904	24,189	24,477	24,768	25,063	25,362	25,664	25,969	26,279	26,592	26,908	27,229
Total Cost Savings:	616,437	25,294	25,510	25,728	25,950	26,174	21,744	22,003	22,265	22,530	22,798	23,070	23,345	23,623	23,904	24,189	24,477	24,768	25,063	25,362	25,664	25,969	26,279	26,592	26,908	27,229
Expenses:																										
Maintenance	(29,543)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)
Total Expenses:		(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)
Financing:		$																								
% Downpayment:	100%	393,906																								
% Loan:	0%	0																								
Estimated interest rate on loan (%):	5.0%																									
Term of loan (full yrs):	10																									
Initial Capital Cost (Downpayment)		(393,906)																								
Equipment Loan Principal Payment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipment Loan Interest Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Financing Cost:	(393,906)	(393,906)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRE-TAX CASH FLOW, NET*:	192,988	(369,793)	24,328	24,546	24,768	24,993	20,562	20,821	21,083	21,348	21,617	21,888	22,163	22,441	22,722	23,007	23,295	23,587	23,882	24,180	24,482	24,788	25,097	25,410	25,727	26,047
PRE-TAX CASH FLOW, CUMULATIVE:		(369,793)	(345,465)	(320,919)	(296,151)	(271,159)	(250,596)	(229,775)	(208,692)	(187,343)	(165,726)	(143,838)	(121,675)	(99,234)	(76,512)	(53,505)	(30,210)	(6,623)	17,258	41,438	65,920	90,708	115,805	141,215	166,941	192,988
Federal tax calculation (+ = refund)																										
Savings as a result of project	(586,894)	(24,113)	(24,328)	(24,546)	(24,768)	(24,993)	(20,562)	(20,821)	(21,083)	(21,348)	(21,617)	(21,888)	(22,163)	(22,441)	(22,722)	(23,007)	(23,295)	(23,587)	(23,882)	(24,180)	(24,482)	(24,788)	(25,097)	(25,410)	(25,727)	(26,047)
MACRS Accelerated Depr. w/yr 1 bonus (%)		20.0%	32.0%	19.2%	11.5%	11.5%	5.8%																			
Federal Depreciation	334,820	66,964	107,142	64,285	38,504	38,504	19,420	0	0	0	0	0	0	0												
Interest deduction on loan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
State tax deduction	15,053	601	(663)	(646)	(628)	(611)	(957)	(936)	(916)	(895)	(874)	(853)	(832)	470	1,772	1,795	1,817	1,840	1,863	1,886	1,910	1,933	1,958	1,982	2,007	2,032
Annual taxable income	(237,020)	43,452	82,152	39,094	13,108	12,901	(2,099)	(21,758)	(21,999)	(22,244)	(22,491)	(22,741)	(22,995)	(21,971)	(20,950)	(21,212)	(21,478)	(21,747)	(22,019)	(22,294)	(22,572)	(22,854)	(23,139)	(23,428)	(23,720)	(24,015)
Taxes due before ITC (+ = refund)	(82,957)	15,208	28,753	13,683	4,588	4,515	(735)	(7,615)	(7,700)	(7,785)	(7,872)	(7,959)	(8,048)	(7,690)	(7,332)	(7,424)	(7,517)	(7,611)	(7,707)	(7,803)	(7,900)	(7,999)	(8,099)	(8,200)	(8,302)	(8,405)
Federal tax credit (ITC)	118,172	118,172																								
Taxes due after ITC	35,215	133,380	28,753	13,683	4,588	4,515	(735)	(7,615)	(7,700)	(7,785)	(7,872)	(7,959)	(8,048)	(7,690)	(7,332)	(7,424)	(7,517)	(7,611)	(7,707)	(7,803)	(7,900)	(7,999)	(8,099)	(8,200)	(8,302)	(8,405)
State tax calculation (+ = refund)																										
Savings as a result of project	(586,894)	(24,113)	(24,328)	(24,546)	(24,768)	(24,993)	(20,562)	(20,821)	(21,083)	(21,348)	(21,617)	(21,888)	(22,163)	(22,441)	(22,722)	(23,007)	(23,295)	(23,587)	(23,882)	(24,180)	(24,482)	(24,788)	(25,097)	(25,410)	(25,727)	(26,047)
State Depreciation	393,906	16,413	32,825	32,825	32,825	32,825	32,825	32,825	32,825	32,825	32,825	32,825	32,825	16,413	0											
Interest deduction on loan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual taxable income	(192,988)	(7,700)	8,498	8,279	8,058	7,833	12,263	12,004	11,742	11,477	11,209	10,937	10,662	(6,028)	(22,722)	(23,007)	(23,295)	(23,587)	(23,882)	(24,180)	(24,482)	(24,788)	(25,097)	(25,410)	(25,727)	(26,047)
Taxes due before ITC (+ = refund)	(15,053)	(601)	663	646	628	611	957	936	916	895	874	853	832	(470)	(1,772)	(1,795)	(1,817)	(1,840)	(1,863)	(1,886)	(1,910)	(1,933)	(1,958)	(1,982)	(2,007)	(2,032)
State tax credit (ITC to 200 kW)	0	0																								
Taxes due after ITC	(15,053)	(601)	663	646	628	611	957	936	916	895	874	853	832	(470)	(1,772)	(1,795)	(1,817)	(1,840)	(1,863)	(1,886)	(1,910)	(1,933)	(1,958)	(1,982)	(2,007)	(2,032)
AFTER-TAX CASH FLOW, NET*:	213,150	(237,014)	53,744	38,875	29,984	30,119	20,784	14,142	14,299	14,458	14,619	14,782	14,947	14,281	13,617	13,788	13,961	14,135	14,312	14,491	14,672	14,855	15,041	15,228	15,418	15,610
AFTER-TAX CASH FLOW, CUMULATIVE:		(237,014)	(183,270)	(144,395)	(114,411)	(84,292)	(63,508)	(49,366)	(35,066)	(20,608)	(5,988)	8,793	23,740	38,021	51,639	65,427	79,387	93,523	107,835	122,326	136,998	151,853	166,894	182,122	197,540	213,150

8.0%	**Internal Rate of Return**
10.41	**Payback Term**
610	**NPV @ 8.0% Discount Rate**

Not For Profit / Government

Savings:	25-Yr Totals	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Performance Based Incentive	23,714	4,800	4,771	4,743	4,714	4,686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Electricity Purchases	592,723	20,494	20,738	20,985	21,235	21,488	21,744	22,003	22,265	22,530	22,798	23,070	23,345	23,623	23,904	24,189	24,477	24,768	25,063	25,362	25,664	25,969	26,279	26,592	26,908	27,229
Total Cost Savings:	616,437	25,294	25,510	25,728	25,950	26,174	21,744	22,003	22,265	22,530	22,798	23,070	23,345	23,623	23,904	24,189	24,477	24,768	25,063	25,362	25,664	25,969	26,279	26,592	26,908	27,229
Expenses:																										
Maintenance	(29,543)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)
Total Expenses:		(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)	(1,182)
Financing:		$																								
% Downpayment:	100%	393,906																								
% Loan:	0%	0																								
Estimated interest rate on loan (%):	5.0%																									
Term of loan (full yrs):	10																									
Initial Capital Cost (Downpayment)		(393,906)																								
Equipment Loan Principal Payment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipment Loan Interest Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Financing Cost:	(393,906)	(393,906)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CASH FLOW, NET*:	192,988	(369,793)	24,328	24,546	24,768	24,993	20,562	20,821	21,083	21,348	21,617	21,888	22,163	22,441	22,722	23,007	23,295	23,587	23,882	24,180	24,482	24,788	25,097	25,410	25,727	26,047
CASH FLOW, CUMULATIVE:		(369,793)	(345,465)	(320,919)	(296,151)	(271,159)	(250,596)	(229,775)	(208,692)	(187,343)	(165,726)	(143,838)	(121,675)	(99,234)	(76,512)	(53,505)	(30,210)	(6,623)	17,258	41,438	65,920	90,708	115,805	141,215	166,941	192,988

3.3%	**Internal Rate of Return**
17.28	**Payback Term**
($74,060)	**NPV @ 6.0% Discount Rate**

PV Installations by Month

year	month	Total MW solar installed by month-end	New solar MW DC installed each month	Monthly solar MWh eligible for PBI	Total solar MWh eligible for PBI by year-end
2008	6	0.001		1	
2008	7	0.4	#N/A	52	
2008	8	0.9	0.43	104	
2008	9	1.3	0.43	156	
2008	10	1.7	0.43	208	
2008	11	2.1	0.43	260	
2008	12	2.6	0.43	311	*1092*
2009	1	3.0	0.39	359	
2009	2	3.4	0.39	407	
2009	3	3.7	0.39	454	
2009	4	4.1	0.39	502	
2009	5	4.5	0.39	549	
2009	6	4.9	0.39	597	
2009	7	5.3	0.39	644	
2009	8	5.7	0.39	692	
2009	9	6.1	0.39	739	
2009	10	6.5	0.39	787	
2009	11	6.9	0.39	834	
2009	12	7.3	0.39	881	*7446*
2010	1	8.0	0.72	969	
2010	2	8.7	0.72	1056	
2010	3	9.4	0.72	1144	
2010	4	10.2	0.72	1231	
2010	5	10.9	0.72	1319	
2010	6	11.6	0.72	1406	
2010	7	12.3	0.72	1493	
2010	8	13.0	0.72	1580	
2010	9	13.8	0.72	1667	
2010	10	14.5	0.72	1754	
2010	11	15.2	0.72	1842	
2010	12	15.9	0.72	1929	*17390*
2011	1	17.2	1.33	2089	
2011	2	18.6	1.33	2250	
2011	3	19.9	1.33	2411	
2011	4	21.2	1.32	2571	
2011	5	22.5	1.32	2732	
2011	6	23.9	1.32	2892	
2011	7	25.2	1.32	3053	
2011	8	26.5	1.32	3213	
2011	9	27.8	1.32	3373	
2011	10	29.2	1.32	3533	
2011	11	30.5	1.32	3693	
2011	12	31.8	1.32	3853	*35665*
2012	1	34.2	2.44	4149	
2012	2	36.7	2.44	4445	
2012	3	39.1	2.44	4740	
2012	4	41.5	2.44	5036	
2012	5	44.0	2.44	5331	
2012	6	46.4	2.43	5626	
2012	7	48.8	2.43	5921	
2012	8	51.3	2.43	6216	
2012	9	53.7	2.43	6510	
2012	10	56.1	2.43	6805	
2012	11	58.6	2.43	7099	
2012	12	61.0	2.43	7393	*69269*
2013	1	65.5	4.49	7937	
2013	2	70.0	4.49	8481	
2013	3	74.5	4.48	9025	
2013	4	78.9	4.48	9568	
2013	5	83.4	4.48	10111	
2013	6	87.9	4.48	10654	
2013	7	92.4	4.48	11196	
2013	8	96.8	4.47	11738	
2013	9	101.3	4.47	12280	
2013	10	105.8	4.47	12822	
2013	11	110.2	4.47	13363	
2013	12	114.7	4.46	13904	*131079*

Adj.(1) --> 99.95%
to reflect assumed monthly degradation in solar output.

Year of Operation	Solar MWh Generated & Eligible for PBI	*Cumulative MW of solar electricity installations (DC adjusted for degradation)*
2007	1,092	2.6
2008	7,446	7.3
2009	17,390	15.9
2010	35,665	31.8
2011	69,269	61.0
2012	131,079	114.7
2013	244,788	213.5
2014	453,991	395.4
2015	838,903	729.9
2016	1,547,119	1345.5
2017	1,951,706	1338.7
2018	1,941,893	1332.0

2014	1	123.0	8.26	14905	
2014	2	131.2	8.25	15906	
2014	3	139.5	8.25	16906	
2014	4	147.7	8.25	17905	
2014	5	156.0	8.24	18904	
2014	6	164.2	8.24	19903	
2014	7	172.4	8.23	20901	
2014	8	180.7	8.23	21898	
2014	9	188.9	8.23	22895	
2014	10	197.1	8.22	23892	
2014	11	205.3	8.22	24888	
2014	12	213.5	8.21	25883	*244788*
2015	1	228.7	15.19	27725	
2015	2	243.9	15.19	29566	
2015	3	259.1	15.18	31406	
2015	4	274.3	15.17	33245	
2015	5	289.4	15.16	35083	
2015	6	304.6	15.16	36920	
2015	7	319.7	15.15	38756	
2015	8	334.9	15.14	40591	
2015	9	350.0	15.13	42426	
2015	10	365.1	15.13	44259	
2015	11	380.3	15.12	46092	
2015	12	395.4	15.11	47923	*453991*
2016	1	423.3	27.96	51312	
2016	2	451.3	27.94	54699	
2016	3	479.2	27.93	58084	
2016	4	507.1	27.91	61467	
2016	5	535.0	27.90	64849	
2016	6	562.9	27.89	68229	
2016	7	590.8	27.87	71608	
2016	8	618.6	27.86	74984	
2016	9	646.5	27.84	78359	
2016	10	674.3	27.83	81733	
2016	11	702.1	27.82	85104	
2016	12	729.9	27.80	88474	*838903*
2017	1	781.4	51.44	94709	
2017	2	832.8	51.41	100941	
2017	3	884.2	51.39	107170	
2017	4	935.5	51.36	113395	
2017	5	986.9	51.34	119617	
2017	6	1,038.2	51.31	125837	
2017	7	1,089.4	51.28	132053	
2017	8	1,140.7	51.26	138266	
2017	9	1,191.9	51.23	144476	
2017	10	1,243.1	51.21	150683	
2017	11	1,294.3	51.18	156886	
2017	12	1,345.5	51.16	163087	*1547119*
2018	1	1,344.9	-0.57	163018	
2018	2	1,344.4	-0.57	162950	
2018	3	1,343.8	-0.57	162881	
2018	4	1,343.2	-0.56	162813	
2018	5	1,342.7	-0.56	162745	
2018	6	1,342.1	-0.56	162676	
2018	7	1,341.5	-0.56	162608	
2018	8	1,341.0	-0.56	162539	
2018	9	1,340.4	-0.56	162471	
2018	10	1,339.8	-0.56	162403	
2018	11	1,339.3	-0.56	162335	
2018	12	1,338.7	-0.56	162267	*1951706*
2019	1	1,338.2	-0.56	162198	
2019	2	1,337.6	-0.56	162130	
2019	3	1,337.0	-0.56	162062	
2019	4	1,336.5	-0.56	161994	
2019	5	1,335.9	-0.56	161926	
2019	6	1,335.3	-0.56	161858	
2019	7	1,334.8	-0.56	161790	
2019	8	1,334.2	-0.56	161722	
2019	9	1,333.7	-0.56	161654	
2019	10	1,333.1	-0.56	161587	
2019	11	1,332.5	-0.56	161519	
2019	12	1,332.0	-0.56	161451	*1941893*

1.3.4 ENERGY STORAGE

Technology Description


A 5-MVA battery energy-storage system for power quality and peak shaving.

Advanced storage technologies under active development include processes that are mechanical (flywheels, pneumatic), electrochemical (advanced batteries, reversible fuel cells, hydrogen, ultracapacitors), and purely electrical (superconducting magnetic storage). Energy storage devices are added to the utility grid to improve productivity, increase reliability or defer equipment upgrades. Energy storage devices must be charged and recharged with electricity generated elsewhere. Because the storage efficiency (output compared to input energy) is less than 100%, on a kilowatt-per-kilowatt basis, energy storage does not directly decrease CO_2 production. The exception to this rule is the use of advanced energy storage in conjunction with intermittent renewable energy sources, such as photovoltaics and wind, that produce no direct CO_2. Energy storage allows these intermittent resources to be dispatchable.

Energy-storage devices do positively affect CO_2 production on an industrial output basis by providing high-quality power, maximizing industrial productivity. New battery technologies, including sodium sulfur and flow batteries, significantly improve the energy and power densities for stationary battery storage as compared to traditional flooded lead-acid batteries.

System Concepts

- *Stationary applications:* The efficiency of a typical steam-power plant falls from about 38% at peak load to 28%-31% at night. Utilities and customers could store electrical energy at off-peak times, allowing power plants to operate near peak efficiency. The stored energy could be used during high-demand periods displacing low-efficiency peaking generators. CO_2 emissions would be reduced if the efficiency of the energy storage were greater than 85%. Energy storage also can be used to alleviate the pressure on highly loaded components in the grid (transmission lines, transformers, etc.) These components are typically only loaded heavily for a small portion of the day. The storage system would be placed downstream from the heavily loaded component. This would reduce electrical losses of overloaded systems. Equipment upgrades also would be postponed, allowing the most efficient use of capital by utility companies. For intermittent renewables, advnaced energy storage technology would improve their applicability.
- *Power quality:* The operation of modern, computerized manufacturing depends directly on the quality of power the plant receives. Any voltage sag or momentary interruption can trip off a manufacturing line and electronic equipment. Industries that are particularly sensitive are semiconductor manufacturing, plastics and paper manufacturing, electronic retailers, and financial services such as banking, stock brokerages, and credit card-processing centers. If an interruption occurs that disrupts these processes, product is often lost, plant cleanup can be required, equipment can be damaged, and transactions can be lost. Any loss must be made up decreasing the overall efficiency of the operation, thereby increasing the amount of CO_2 production required for each unit of output. Energy-storage value is usually measured economically with

the cost of power-quality losses, which is estimated in excess of $1.5 B/year in the United States alone. Industry is also installing energy-storage systems to purchase relatively cheap off-peak power for use during on-peak times. This use dovetails very nicely with the utilities' interest in minimizing the load on highly loaded sections of the electric grid. Many energy-storage systems offer multiple benefits. (An example is shown in the photo.) This 5-MVA, 3.5-MWh valve-regulated lead-acid battery system is installed at a lead recycling plant in the Los Angeles, California, area. The system provides power-quality protection for the plant's pollution-control equipment, preventing an environmental release in the event of a loss of power. The system carries the critical plant loads while an orderly shutdown occurs. The battery system also in discharged daily during the afternoon peak (and recharged nightly), reducing the plant's energy costs.

Representative Technologies

For utilities, the most mature storage technology is pumped hydro; however, it requires topography with significant differences in elevation, so it's only practical in certain locations. Compressed-air energy storage uses off-peak electricity to force air into underground caverns or dedicated tanks, and releases the air to drive turbines to generate on-peak electricity; this, too, is location specific. Batteries, both conventional and advanced, are commonly used for energy-storage systems. Advanced flowing electrolyte batteries offer the promise of longer lifetimes and easier scalability to large, multi-MW systems. Superconducting magnetic energy storage (SMES) is largely focused on high-power, short-duration applications such as power quality and transmission system stability. Ultracapacitors have very high power density but currently have relatively low total energy capacity and are also applicable for high-power, short-duration applications. Flywheels are now commercially viable in power quality and UPS applications, and emerging for high power, high-energy applications.

Technology Status - Utilities

Technology	Efficiency [%]	Energy density [W-h/kg]	Power density [kW/kg]	Sizes [MW-h]	Comments
Pumped hydro	75	0.27/100 m	low	5,000-20,000	37 existing in U.S.
Compressed gas	70	0	low	250-2,200	1 U.S., 1 German
SMES	90+	0	high	20 MW	high-power applications
Batteries	70–84	30-50	0.2-0.4	17-40	Most common device
Flywheels	90+	15-30	1-3	0.1-20 kWh	US & foreign development
Ultracapacitors	90+	2-10	high	0.1-0.5 kWh	High-power density

System Components

Each energy-storage system consists of four major components: the storage device (battery, flywheel, etc.); a power-conversion system; a control system for the storage system, possibly tied in with a utility SCADA (Supervisory Control And Data Acquisition) system or industrial facility control system; and interconnection hardware connecting the storage system to the grid. All common energy-storage devices are DC devices (battery) or produce a varying output (flywheels) requiring a power conversion system to connect it to the AC grid. The control system must manage the charging and discharging of the system, monitor the state of health of the various components and interface with the local environment at a minimum to receive on/off signals. Interconnection hardware allows for the safe connection between the storage system and the local grid.

Current Research, Development, and Demonstration

RD&D Goals

- Research program goals in this area focus on energy-storage technologies with high reliability and affordable costs. For capital cost this is interpreted to mean less than or equal to those of some of lower cost new power generation options ($400–$600/kW). Battery storage systems range from $300-$2000/kW. For operating cost, this figure would range from compressed gas energy storage, which can cost as little as $1 to $5/kWh, to pumped hydro storage, which can range between $10 and $45/kWh.

RD&D Challenges

- The major hurdles for all storage technologies are cost reduction and developing methods of accurately identifying all the potential value streams from a given installation. Advanced batteries need field experience and manufacturing increases to bring down costs. Flywheels need further development of failsafe designs and/or lightweight containment. Magnetic bearings could reduce parasitic loads and make flywheels attractive for small uninterruptible power supplies and possibly larger systems using multiple individual units. Ultracapacitor development requires improved large modules to deliver the required larger energies. Advanced higher-power batteries with greater energy storage and longer cycle life are necessary for economic large-scale utility and industrial applications.

RD&D Activities

- The Japanese are investing heavily in high-temperature, sodium-sulfur batteries for utility load-leveling applications. They also are pursuing large-scale vanadium reduction-oxidation battery chemistries. The British are developing a utility-scale flow battery system based on sodium bromine/sodium bromide chemistry. DOE's Energy Storage Systems Program works on improved and advanced electrical energy storage for stationary (utility, customer-side, and renewables) applications. It focuses on three areas: system integration using near-term components including field evaluations, advanced component development, and systems analysis. This work is being done in collaboration with a number of universities and industrial partners.

Commercialization and Deployment Activities

- For utilities, only pumped hydro has made a significant penetration with approximately 37 GW.
- Approximately 150 MW of utility peak-shaving batteries are in service in Japan.
- Two 10-MW flow battery systems are under construction – one in the United Kingdom and the other in the United States.
- Megawatt-scale power quality systems are cost effective and entering the marketplace today.

Olivenhain-Hodges
Pumped Storage Project

Olivenhain-Hodges Pumped Storage Project

San Diego County Water Authority

FACT SHEET

The Water Authority is a public agency serving the San Diego region as a wholesale supplier of water. The Water Authority works through its 23 member agencies to provide a safe, reliable water supply to support the region's $130 billion economy and the quality of life of 3 million residents.

San Diego County Water Authority

4677 Overland Ave.
San Diego, CA
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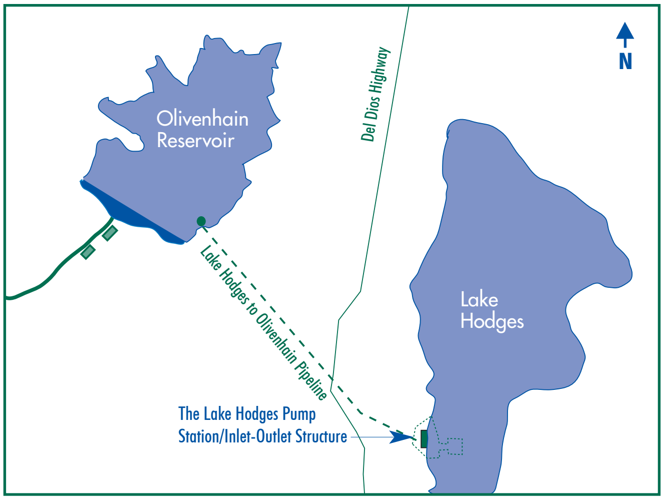
The Olivenhain-Hodges Pumped Storage Project is an integral component of the Lake Hodges projects, providing electrical generating capacity while enhancing Emergency Storage Project requirements to ensure regional water reliability.

Background

In 2005, the Water Authority is scheduled to begin construction of the Lake Hodges projects, which include the Lake Hodges to Olivenhain Pipeline and the Lake Hodges Pump Station/Inlet-Outlet structure.

- The Lake Hodges to Olivenhain Pipeline is a 1¼-mile-long water transmission tunnel between the Lake Hodges Pump Station and Olivenhain Reservoir.
- The Lake Hodges Pump Station/Inlet-Outlet structure, located at Lake Hodges, will pump water from the lake to the Olivenhain Reservoir. It will also control the flow of water from Olivenhain Reservoir to Lake Hodges.



By providing a means to convey water between Lake Hodges and the Olivenhain Reservoir, these projects will increase operational flexibility and water storage capacity for San Diego County. The water will also be available for emergency use in case of a natural disaster such as earthquake or drought. Water pumped from Lake Hodges to Olivenhain Reservoir can readily be conveyed to the Water Authority's Second Aqueduct for further distribution throughout the county.

Conserving Energy

During the planning phase of the Lake Hodges projects' design, the Water Authority recognized the hydroelectric generating potential of the 770-foot elevation difference between Olivenhain Reservoir and Lake Hodges. The Lake Hodges Pump Station, as originally planned, contained three vertical pumps and two pressure-control valves. By replacing the pressure-control valves, pumps and motors with reversible motor-generator/pump turbines and appropriately sizing the tunnel pipeline, all of the elements of a pumped-storage capability became available. Energy created during the transfer of water from the Olivenhain Reservoir to Lake Hodges would now be captured and utilized in the region. This captured energy will provide revenue to pay back the cost of the pumped-storage equipment and facilities and support other Water Authority activities.

The Lake Hodges Pump Station's pump-turbines will produce a maximum output of 40 megawatts during water transfers from Olivenhain Reservoir to Lake Hodges. The electricity generated will be transmitted to an outdoor switchyard located adjacent to the pump station, then to a 1,400-foot-long transmission line that will connect to the existing local transmission system.

The original above-ground pump station structure was modified to be mostly below ground to accommodate the pumped storage equipment, providing the added benefit of reduced visual impact to the area.

When considering both revenue generated and energy saved, the pumped-storage facility will be a major enhancement to the Lake Hodges projects. Construction of the Lake Hodges projects is scheduled to be complete by 2008.

JULY 2004

FuelCell Energy
World Leader in Secure, Ultra-Clean Power

Sheraton San Diego

problem:

Starwood Hotels, managers of the Sheraton San Diego Hotel & Marina in San Diego, California, sought to find an affordable and efficient means of producing environmentally-friendly baseload electrical power for this popular hotel and resort.

solution:

FuelCell Energy® provided the answer, installing a one-megawatt (1 MW) stationary fuel cell power plant made up of four 250-kilowatt Direct FuelCell® 300A (DFC300A®) power plants from FuelCell Energy that are classified as an "Ultra-Clean" technology under California law, thus qualifying the new system for considerable financial subsidies. Benefits such as high-reliability, ultra-low emissions, and quiet operation made the fuel cell system a perfect fit for the hotel's needs. As an added benefit, heat produced within the fuel cell is used to support the hotel's hot water needs and to heat three of the facility's large pools.

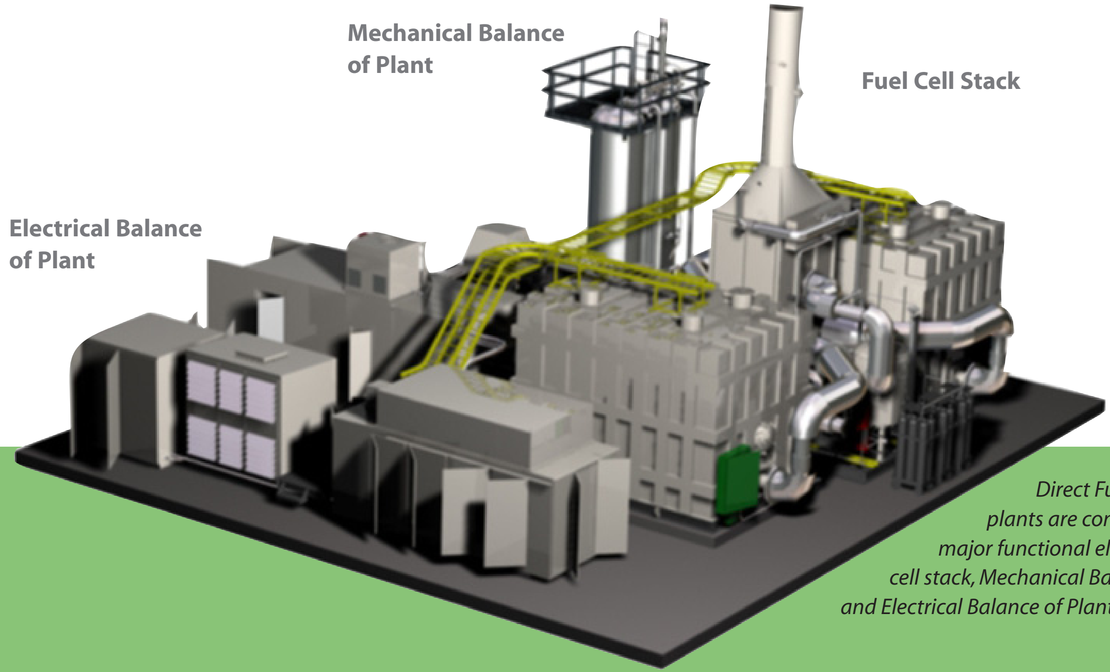
result:

The fuel cell plant supplies 60 - 80% of the hotel's baseload power requirements. Inconspicuously located adjacent to the Sheraton's tennis courts, the fuel cell system generates so little noise pollution, it is virtually unnoticeable. The system has proven very reliable, attaining a reliability rating of more than 98% since operation began.

The power plant has also generated substantial interest from hotel guests, who are curious about the new power system and how it operates. In fact, the Sheraton estimates they have booked more than 1,000 rooms in the last year due to interest in the fuel cell system, and their reputation for environmentally-friendly practices.

About DFC Power Plants

FuelCell Energy's DFC systems are self-contained commercial-grade power plants providing high-quality, baseload electric power using biofuels – gases from wastewater treatment, food processing, and landfills – in addition to natural gas.



Direct FuelCells power plants are comprised of three major functional elements; the fuel cell stack, Mechanical Balance of Plant and Electrical Balance of Plant.

As a result of the resounding success attained after one year of operating the initial 1 MW fuel cell plant, Starwood added a second fuel cell installation to the property in July 2006. Two 250-kilowatt DFC300MA™ fuel cells were installed at the West Tower portion of the property, bringing the total power output to 1.5 MW, making it the single largest commercial fuel cell installation in the world. The West Tower fuel cell plant provides 100% of the power requirement and 100% of the domestic hot water heat source for the West Tower.

About Starwood Hotels

Starwood Hotels & Resorts Worldwide, Inc. is one of the leading hotel and leisure companies in the world with approximately 870 properties in more than 100 countries. Starwood owns, operates, and franchises such internationally renowned brands as St. Regis®, The Luxury Collection®, Sheraton®, Westin®, Four Points® by Sheraton, W® Hotels and Resorts, and Starwood Vacation Ownership, Inc. For more information, please visit **www.starwoodhotels.com.**

About FuelCell Energy

FuelCell Energy develops and markets Ultra-Clean power plants that generate electricity with higher efficiency than distributed generation plants of similar size and with virtually no air pollution. For more information on the company, its products, and its world-wide commercial distribution alliances, please visit **www.fuelcellenergy.com.**

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FuelCell Energy
World Leader in Secure, Ultra-Clean Power

Attachment O: Clean Energy Coalition Letter to Chairman of Maryland Public Service Commission

August 17, 2007

Chairman Steven B. Larsen
Maryland Public Service Commission
6 St. Paul Street, 16th Floor
Baltimore, MD 21202

Mr. Karl V. Pfirrman
Interim President and CEO
PJM, LLC
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

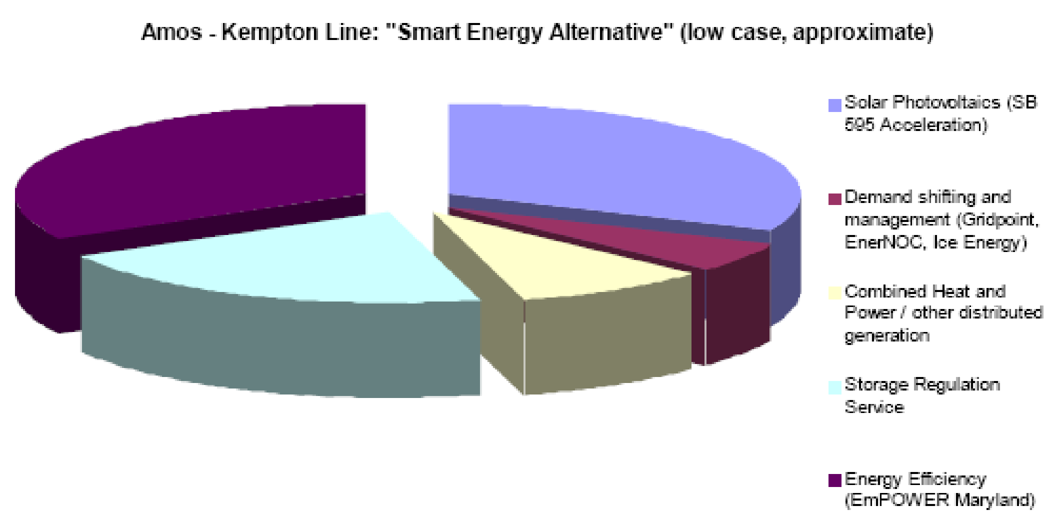
Dear Chairman Larsen and President Pfirrman:

We write you as a coalition of clean energy developers to urge that the Maryland Public Service Commission undertake a thorough study of specific renewable energy and demand management measures as an alternative to the proposed Amos, West Virginia to Kempton, Maryland transmission expansion project.

Though comprehensive capacity numbers have not yet been released, we understand that the 290 mile, estimated $1.8 billion line, proposed for completion in 2012, is required to service approximately 1800 MW in demand. We understand that the electricity will be wheeled in from coal fired power plants in the Midwest.

As you are no doubt aware, landmark legislation passed by the General Assembly and signed by Governor O'Malley has placed Maryland on track to add approximately 1500 MW of solar energy over the next 15 years. It is our considered opinion that accelerating the deployment of peak-coincident solar energy , along with other high efficiency distributed generation and "smart grid" technologies, can offset the need for the Amos – Kempton line.

We believe that this accelerated, continuous development could be had at a ratepayer cost less than the proposed $1.8 billion and with significantly reduced delivery and financial risk as compared to a single massive transmission corridor.



Further, these resources would bring low-emissions *generation* capability into Maryland. The choice is between expending ratepayer funding on low-risk, low-emissions distributed generation, or relying on a single, controversial, high-risk project that will only enable the export of our energy dollars to produce air pollution upwind.

It is time that the PJM and the Commission begin to consider alternatives to the expensive solutions provided by 20th century technologies.

Collectively the undersigned are convinced we can provide at least 1800 MW of distributed generation and resources in the specified time frame. Based on the information available, we feel that this should be sufficient to offset the relevant congestion concerns.

However, we cannot provide a more accurate or thorough analysis of this alternative without access to PJM's modeling capabilities. We urge you to have the probabilistic consumption models used by PJM adapted to the scenario we present, and we stand ready to provide the appropriate inputs and generator profiles.

With almost two billion dollars on the table, and facing profound and controversial changes to the landscape, we feel that the Commission and PJM have the responsibility to consider all practicable alternatives. We would sincerely appreciate the opportunity to discuss our alternative in greater depth and contribute to the development of a more thorough and comprehensive analysis for Maryland.

Sincerely,

Jigar Shah /s/

Jigar Shah, Chief Strategy Officer
SunEdison, LLC
443-909-7200

Charlie Gay /s/

Charlie Gay, Vice President and
General Manager
Solar Business Unit, Applied Materials

Todd Foley /s/

Todd Foley, Director of External Affairs
BP Solar

Lisa Krueger /s/

Lisa Krueger, Vice President,
Sustainable Development
First Solar

Peter Corsell /s/

Peter Corsell, President and CEO
GridPoint

Roger Efird /s/

Roger Efird, CEO
SunTech America

Richard Feldt /s/

Richard Feldt, CEO
Evergreen Solar

Frank Ramirez /s/

Frank Ramirez, CEO
Ice Energy

Tim Healey /s/

Tim Healey, CEO
EnerNOC

Richard Brent /s/

Richard S. Brent
Director, Government Affairs
Solar Turbines, Incorporated

cc: People's Counsel, Paula Carmody,
Maryland Office of the People's Counsel