Appendices

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Appendix A Cost Factors for a Wind Farm

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

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

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

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

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

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

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

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

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

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

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

Table A-1. Wind Cost Summary

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

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

Levelized Cost Analysis in Class 6 Region*

Private Finance

11.8% Avg. Cost of Capital; 2 cent/kwh Production Tax Credit.

Capital Cost:		
Installed Cost Rate	$1,350	per kw
Capacity	400,000	kw
Total Cost	$540,000,000	
Tax Credit	0%	
Net Cost	$540,000,000	
Utility Finance:		
Avg. Cost of Capital	11.8%	
Term	30	yrs
Financing Cost	$1,911,600,000	
Operation and Maintenance:		
Personnel	64	
Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,520,000	
Maintenance &other rate/capital-yr.	1.6%	
Maintenance & other cost/year	$8,640,000	
Annual O&M	$12,160,000	
Lifecycle O&M	$364,800,000	
Electric Generation:		
Capacity Factor	35%	
Generation rate	3,066	kwh/kw
Gross Annual generation	1,226,400,000	kwh
Parasitic Load factor/loss	0.1%	
Annual Loss	1,226,400	kwh
Net Annual Output	1,225,173,600	kwh

Public Finance

Bond financing no tax credits

Capital Cost:		
Installed Cost Rate	$1,350	per kw
Capacity	400,000	kw
Total Cost	$540,000,000	
Tax Credit	0%	
Net Cost	$540,000,000	
Public Finance:		
Bond Rate	5.25%	
Term	30	yrs
Financing Cost	$850,500,000	
Operation and Maintenance:		
Personnel	64	
Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,520,000	
Maintenance &other rate/capital-yr.	1.6%	
Maintenance & other cost/year	$8,640,000	
Annual O&M	$12,160,000	
Lifecycle O&M	$364,800,000	
Electric Generation:		
Capacity Factor	35%	
Generation rate	3,066	kwh/kw
Gross Annual generation	1,226,400,000	kwh
Parasitic Load factor/loss	0.1%	
Annual Loss	1,226,400	kwh
Net Annual Output	1,225,173,600	kwh

Private Finance

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

Public Finance

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

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

Appendix B Solar Thermal w/ Natural Gas and Cogeneration

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

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

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

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

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

Table B-1. Concentrating Solar Thermal Power

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

Capital Cost:		
Installed Cost Rate		
Target	$2,500	per kw
Capacity	160,000	kws
Total Cost	$400,000,000	
Tax Credit (enter 10% or 30%)	10%	
Net Cost	$360,000,000	
Private Finance		
Avg. Cost of Capital	11.8%	
Term	30	years
Financing Cost	$1,274,400,000	
Operation and Maintenance:		
Personnel	70	
Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,826,087	
Maintenance &other rate/capital-yr.	0.6%	
Maintenance & other cost/year	$2,400,000	
Annual O&M	$6,226,087	
Lifecycle O&M	$186,782,609	
O&M per kwh	$0.021	

Public Finance, 2010 to 2015

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

Reference Natural Gas Price

Capital Cost:		
Installed Cost Rate		
Target	$2,500	per kw
Capacity	160,000	kws
Total Cost	$400,000,000	
Tax Credit	0%	
Net Cost	$400,000,000	
Public Finance:		
Bond Rate	5.25%	
Term	30	years
Financing Cost	$630,000,000	
Operation and Maintenance:		
Personnel	70	
Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,826,087	
Maintenance &other rate/capital-yr.	0.6%	
Maintenance & other cost/year	$2,400,000	
Annual O&M	$6,226,087	
Lifecycle O&M	$186,782,609	
O&M per kwh	$0.021	

Public Finance, 2010 to 2015

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

High Natural Gas Price Scenario

Capital Cost:		
Installed Cost Rate		
Target	$2,500	per kw
Capacity	160,000	kws
Total Cost	$400,000,000	
Tax Credit	0%	
Net Cost	$400,000,000	
Public Finance:		
Bond Rate	5.25%	
Term	30	years
Financing Cost	$630,000,000	
Operation and Maintenance:		
Personnel	70	
Assumed avg. Salary	$55,000	
Annual Personnel Cost	$3,826,087	
Maintenance &other rate/capital-yr.	0.6%	
Maintenance & other cost/year	$2,400,000	
Annual O&M	$6,226,087	
Lifecycle O&M	$186,782,609	
O&M per kwh	$0.021	

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

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

Public Finance, 2010 to 2015

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

Reference Natural Gas Price

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

Public Finance, 2010 to 2015

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

High Natural Gas Price Scenario

Solar Electric Generation:		
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Solar 'Electric Generation Cost:		
Lifecycle Cost	$1,216,782,609	
Lifecycle Output	8,897,356,800	kwh
Cost of Electricity	**$0.137**	per kwh
Gas Electric Generation:		
Capacity Factor	11%	
Generation rate	964	kwh/kw
Gross Annual generation	154,176,000	kwh
Fuel Cost	$10.00	per MMBtu
heat rate	9400	btu/kwh
efficiency	0.36	
annual energy input	1,449,254	MMBtu
annual energy cost	$14,492,544	

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$282,604,608	

Combined Cost of Solar/Natural Gas Generation

Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$2,143,787,217	
Combined Cost of Electricity	**$0.159**	

Thermal Energy

annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu

Cost of Electricity Using Cogeneration

cogen heat repurchase rate	$6.50	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Public Finance, 2010 to 2015

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

Reference Natural Gas Price

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$282,604,608	

Combined Cost of Solar/Natural Gas Generation

Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$1,499,387,217	
Combined Cost of Electricity	**$0.111**	

Thermal Energy

annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu

Cost of Electricity Using Cogeneration

cogen heat repurchase rate	$6.50	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Public Finance, 2010 to 2015

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

High Natural Gas Price Scenario

Lifecycle energy input	43,477,632	MMBtu
Lifecycle electricity output	4,625,280,000	kwh
Lifecycle cost of fuel	$434,776,320	

Combined Cost of Solar/Natural Gas Generation

Generation	13,522,636,800	kwh
Capacity Factor	32.2%	
Total Cost	$1,651,558,929	
Cost of electricity	**$0.122**	

Thermal Energy

annual natural gas	1,449,254	MMBtu
annual solar thermal	2,780,500	MMBtu
annual total thermal input	4,229,754	MMBtu
annual generation	450,754,560	kwh
annual heat value	1,537,073	MMBtu
residual heat value	2,692,681	MMBtu

Cost of Electricity Using Cogeneration

cogen heat repurchase rate	$10.00	per MMBtu
recovery rate	50%	
heat recovered per year	1,346,341	MMBtu

Private Finance, 2010 to 2015

w/ tax credit & 11.5% Cost of Capital

Reference Natural Gas Price

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

Public Finance, 2010 to 2015

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

Reference Natural Gas Price

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

Public Finance, 2010 to 2015

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

High Natural Gas Price Scenario

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

Appendix C Natural Gas Costs

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

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

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

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

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

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

Table C-1. Natural Gas Price Projections to 2040

in dollars per million btu

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

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

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

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

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

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

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

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

Natural Gas to Generate 1 KWh					
Cost/MMBtu	$6.50		Size of Plant	160,000	kw
conversion to kwh	3419	btu/kwh	Annual Generation	448,512,000	kwh
fuel-cost/kwh	$0.022		Lifecycle Generation	8,970,240,000	kwh
heat rate	9400	btu/kwh			
efficiency	36.4%		**Lifecycle Costs**		
factor	2.75		Capital Cost	$76,000,000	
electricity fuel-cost/kwh	**$0.061**		Cost of Money	$179,360,000	
			Lifecycle Fuel Cost	$548,081,664	
Cost of Gen Facility			Variable Cost	$51,918,348	
Cost of Equipment	$0.48	per watt	Total Lifecycle Cost	$855,360,012	
lifecycle	20	years			
capacity factor	32%				
output rate	2803	kwh/kw-yr			
life output/watt	56.06	kwh			
unfinanced cost	$0.008	per kwh			
interest rate + ROI	11.8%				
cost of money	$0.020	per kwh			
total cap cost	$0.028	per kwh			
Variable costs	$0.006	per kwh			
Total Gen Costs	**$0.095**	**per kwh**			

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

Natural Gas to Generate 1 KWh					
Cost/MMBtu	$6.50		Size of Plant	500,000	kw
conversion to kwh	3419	btu/kwh	Annual Generation	3,591,600,000	kwh
fuel-cost/kwh	$0.022		Lifecycle Generation	107,748,000,000	kwh
heat rate	6200	btu/kwh			
efficiency	55.1%		**Lifecycle Costs**		
factor	1.81		Capital Cost	$325,000,000	
electricity fuel-cost/kwh	**$0.040**	74.27%	Cost of Money	$1,150,500,000	
			Lifecycle Fuel Cost	$4,342,244,400	
Cost of Gen Facility			Variable Cost	$243,367,254	
Cost of Equipment	$0.65	per watt	Total Lifecycle Cost	$6,061,111,654	
lifecycle	30	years			
capacity factor	82%				
output rate	7183	kwh/kw-yr			
life output/watt	215.50	kwh			
unfinanced cost	$0.003	per kwh			
interest rate + ROI	11.8%				
cost of money	$0.011	per kwh			
total cap cost	$0.014	per kwh			
Variable costs	$0.002	per kwh			
Total Gen Costs	**$0.056**	**per kwh**			

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

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

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

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

Appendix D Photovoltaics

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

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

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

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

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

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

<u>Underlined row shows the typical cost within the last two years for commercial-scale projects in Cal</u>ifornia

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

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

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

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

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

Appendix E SDG&E Rates and San Diego Electric Resources

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

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

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

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

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

ELECTRIC ENERGY COMMODITY COST (EECC)

Schedule DR – Residential customers on separate meters

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

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

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

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

Effective Date	Summer	Winter
02/01/2006	0.08144	0.05617

Department of Water Resources (DWR) Bond Charge

Effective Date	
01/01/2006	0.00485

care and medical baseline excluded

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

Schedule A- Residential

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

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

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

Appendix F Portfolios and Financing

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

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

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

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

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

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

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

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

	Capacity	Percent Load Carrying capacity	Effective Load Carrying Capacity	Capacity Factor	Annual Generation + DR	Estimated Cost		Peak COE low case		Peak COE base case		Peak COE high case	
						Cost/ watt	*Total Cost*	*per kwh*	*annual*	*per kwh*	*annual*	*per kwh*	*annual*
Current Plant Value	700		700	23%	1,410,360,000	$0.15	$105,000,000						
Current Plant Replacement (potential)	620		620	80%	4,344,960,000	$0.65	$403,000,000						
Natural Gas Peaker						*See Table C-5 for calculations →*		$0.081		$0.095		$0.128	
Green Energy Portfolios													
90% Solution													
Wind Plant	400	20%	80	35%	1,226,400,000	$1.35	$540,000,000						
Pumped Storage net adjust	-183	100%		35%	-560,640,000								
Pumped Storage	150	100%	150	32%	420,480,000	$1.00	$150,000,000	$0.094	$39,525,120	$0.094	$39,525,120	$0.094	$39,525,120
Natural Gas Plant	220	100%	220	32%	616,704,000	$0.48	$105,600,000	$0.071	$43,785,984	$0.085	$52,419,840	$0.118	$72,771,072
Solar Thermal w/gas cogen	160	100%	160	32%	448,512,000	$2.50	$400,000,000	$0.091	$40,814,592	$0.091	$40,814,592	$0.092	$41,263,104
Photovoltaic	20	60%	12	17%	29,784,000	$7.00	$140,000,000						
Demand reduction	20	100%	20	20%	35,040,000								
Total	970		642		2,216,280,000		$1,335,600,000	$0.084	$124,125,696	$0.089	$132,759,552	$0.103	$153,559,296
ELCC Target			630	32%	1,766,016,000								

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

	Capacity	Percent Load Carrying capacity	Effective Load Carrying Capacity	Capacity Factor	Annual Generation + DR	**Estimated Cost**		**Peak COE low case**		**Peak COE base case**		**Peak COE high case**	
						Cost/ watt	**Total Cost**	***per kwh***	***annual***	***per kwh***	***annual***	***per kwh***	***annual***
50% Solution													
Wind Plant	150	20%	30	35%	459,900,000	$1.35	$202,500,000						
Pumped Storage net adjust	-80	100%		35%	-224,256,000								
Pumped Storage	60	100%	60	32%	168,192,000	$1.00	$60,000,000	$0.094	$15,810,048	$0.094	$15,810,048	$0.094	$15,810,048
Natural Gas Plant	90	100%	90	32%	252,288,000	$0.48	$43,200,000	$0.071	$17,912,448	$0.085	$21,444,480	$0.118	$29,769,984
Solar Thermal w/gas cogen	160	100%	160	32%	448,512,000	$2.50	$400,000,000	$0.091	$40,814,592	$0.091	$40,814,592	$0.092	$41,263,104
Photovoltaic	20	60%	12	17%	29,784,000	$7.00	$140,000,000						
Demand reduction	20	100%	20	20%	35,040,000								
Total	500		352		1,169,460,000		$845,700,000	$0.086	$74,537,088	$0.09	$78,069,120	$0.10	$86,843,136
ELCC Target			350	32%	981,120,000								
Efficiency of Pumped Storage			*75%*										

Table F-2. Financing Assumptions

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

Appendix G Pollution Comparison Calculations

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

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

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

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

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

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

Notes:

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