GREEN OPPORTUNITY

How California Can Reduce Power Plant Emissions, Protect the Marine Environment, and Save Money

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Contents

Executive Summary

The State of California is currently considering ways to phase out natural gas power plants that use 'once-through cooling' (OTC) technology. This outdated method of power plant cooling uses seawater taken directly from the ocean or from estuaries. In the process, OTC kills billions of fish, larvae and marine mammals each year in California. The phase out, planned for 17 coastal natural gas power plants, presents an opportunity for California to replace the lost power generation with clean generation. In addition to the impacts on marine life, most of these power plants are decades old, are inefficient in their operation, and emit significant amounts of greenhouse gases.

This report provides a cost-benefit analysis of two different scenarios for OTC power plant replacement. The first scenario, the "fossil replacement scenario," examines the costs of repowering the existing power plant generators with new natural gas power plant technology that does not use OTC. The second scenario, the "green energy replacement scenario," examines replacement with clean energy, in particular solar power and energy efficiency.

Renewable technologies are often characterized as more expensive than fossil fuels. However, such characterizations usually fail to include costs other than the direct costs of energy facilities and fuel. In this analysis, we have included externalized costs, including those to the marine habitat, to public health, and to the climate. When these are factored into the cost-benefit analysis, our calculations conclude that the green energy replacement scenario is far more cost effective than the fossil replacement scenario.

This report demonstrates that California can and should retire OTC natural gas power plants. Replacing OTC power plants with renewable energy and efficiency will dramatically reduce externalized costs, including damages to marine life, public health, and the global climate. By meeting stated renewable energy and efficiency goals, California can retire OTC natural gas power plants at a cost less than half of the cost of building new natural gas power plants. California's policy makers should move quickly and expeditiously to replace OTC natural gas power plants with green energy.

Key Findings

- California's 17 aging once through cooling (OTC) natural gas power plants kill billions of fish, larvae and marine mammals every year, contribute to climate change, and cause adverse impacts to human health.
- Most of the aging natural gas power plants are primarily used during peak demand times, usually hot summer afternoons when air conditioning is being used. They are responsible for only 4% of California's electricity supply, but provide a quarter of California's peak power demand of 60,000 megawatts.
- There has been a rapid build-up over the past decade of over 16,000 megawatts in new natural gas power plants around the state, dramatically increasing California's natural gas generation capacity to over 40,000 megawatts.
- By meeting the state's goal of 33 percent renewable energy by 2020 and required efficiency measures, OTC natural gas power plants can be reduced or eliminated without building any new fossil fuel plants.
- Peak load can be served by solar power, which is most productive on sunny, warm days when electricity demand is high, as well as by efficiency measures such as better insulation and windows, more efficient air conditioners, light colored roofing, and shade trees — all intended to keep buildings cool by using less energy.
- Continuing and expanding interruptible power programs, regulating usage, and real-time pricing can also significantly reduce peak demand. In addition, energy storage technologies can shape wind and other renewable energy sources to meet peak power demand.
- Replacing old power plants with new fossil fuel power plants would result in a cost of energy for the new plants of approximately 31 to 39 cents per kilowatt-hour, when external costs are included.

Excessive commitment to peakers may drive out lower cost, more environmentally friendly, and economically efficient solutions. The proper planning decision under these conditions is … to explore the options further.

2002–2012 Electricity Outlook Report, California Energy Commission, February 2002.

- The cost of the Green Energy Replacement scenario, using solar power, ranges from 22 to 29 cents per kilowatt-hour.
- If efficiency savings are included in the portfolio accounting, the average cost of green electricity goes down to about 17 to 21 cents per kilowatt-hour, assuming that the cost of efficiency is zero. In fact, the state's efficiency program is forecast to yield a net savings, which reduces the cost of the Green Energy Replacement scenario even further.
- The proposed Green Energy Replacement Scenario eliminates the prime externalities: damages to marine life, public health, and the global climate. Thus, the full cost of the Green Energy Scenario may be less than half that of new natural gas power plants.
- All the aging natural gas OTC plants should be retired on a schedule consistent with the rate at which renewables and efficiency can be brought on line, so that the state is not bound by long-term commitments to new natural gas plants. Coordinating the retirement of aging plants with the deployment of green energy supplies would allow the state to meet environmental commitments while assuring electric system reliability.

1. At the Crossroads: Natural Gas or Green Energy?

California stands at a crossroads. Over the course of decades a large natural gas power plant infrastructure has been built —totaling 40,000 megawatts— that now supplies nearly half of the state's electricity. Natural gas plants could easily provide a far greater share of electricity, but most are operated only a fraction of the time to meet daily and seasonal peak demand. Some of the plants are old, and at or near the end of their useful service life. In addition to a high cost of operation and a relatively inefficient use of natural gas, the aging natural gas plants cause significant environmental damage. They use billions of gallons of sea water for cooling, a practice that kills sea life over a wide area. The plants also adversely impact air quality and contribute to climate change.

Retirement of the aging plants raises the question of how to replace over 15,000 megawatts of lost power supply—roughly ¼ of the state's peak electricity demand on the hottest summer day. On the one hand they could be replaced by building new natural gas plants. This would commit billions of dollars to new plants that would continue to operate 50 years into the future. Such a path would eliminate the use of sea water cooling, but would also entail the continued depletion of natural gas resources, more air pollution (often in disadvantaged communities), millions of tons of greenhouse gas emissions, and would subject ratepayers to unpredictable natural gas costs.

On the other side of the coin are the state's greenhouse gas reduction and air quality commitments. These include a dramatic increase in the use of renewable energy, improving some of the nation's most polluted air, reducing future energy demand through efficiency improvements, protecting consumers from rising energy prices, and reducing greenhouse gas emissions. The state's own analysis—and common sense—dictate that if California is to achieve the existing mandates, the state must move now to build renewable energy sources and improved energy efficiency, not more fossil fuel-fired power plants.

The Failure of California's Renewable Portfolio Standard

In 2002, California put into law a requirement that investor-owned utilities (IOUs)[1] increase renewable energy to 20 percent by 2017. This law required that the IOUs add a minimum of 1 percent renewables each year until the target was met. In 2002, IOUs obtained about 11 percent of their electricity from renewables. The target date was then advanced to 2010. The state has also established a target of 33 percent renewables by 2020. Unfortunately, however, as energy supplies have increased, the percentage met by renewables has actually declined. This is a direct result of ineffective policies that need to be changed.

The decline in renewable energy has commonly been attributed to two causes: 1) contract failures by project developers and 2) lack of adequate transmission capacity to carry remote sources of renewable resources to urban markets. However, the largest single factor identified by the California Public Utilities Commission was the uncertainty of federal tax credits. The "on again-off again" wind tax credit has subjected the industry to periodic booms and busts over the past decade. The credit pays about 2 cents for each kilowatt-hour generated for the first ten years of operation of a wind farm. This gives a critical boost to the economics of wind farms, reducing the price of wind energy during the early years of operation.

Table 1: Decreasing Percentage of Renewables for California Utilities[2]

		2003	2004	2005	2006	2007
PG&E	RPS Eligible GWh	8,828	8,575	8,543	9,114	9,047
	RPS GWh as % of bundled sales	12.4%	11.6%	11.7%	11.9%	11.4%
SCE	RPS Eligible GWh	12,613	13,248	12,930	12,706	12,465
	RPS GWh as % of bundled sales	17.9%	18.2%	17.2%	16.1%	15.7%
SDG&E	RPS Eligible GWh	550	678	825	900	881
	RPS GWh as % of bundled sales	3.7%	4.3%	5.2%	5.3%	5.2%
TOTAL	RPS Eligible GWh	21,991	22,500	22,298	22,719	22,393
	RPS GWh as % of bundled sales	14.0%	13.9% ⇩	13.6% ⇩	13.2% ⇩	12.7% ⇩

Figure 1. Historic Impact of Production Tax Credit on Annual Installation of Wind Capacity[3]

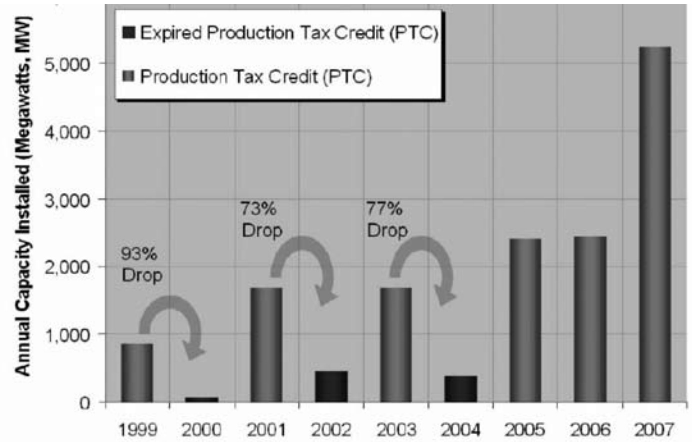
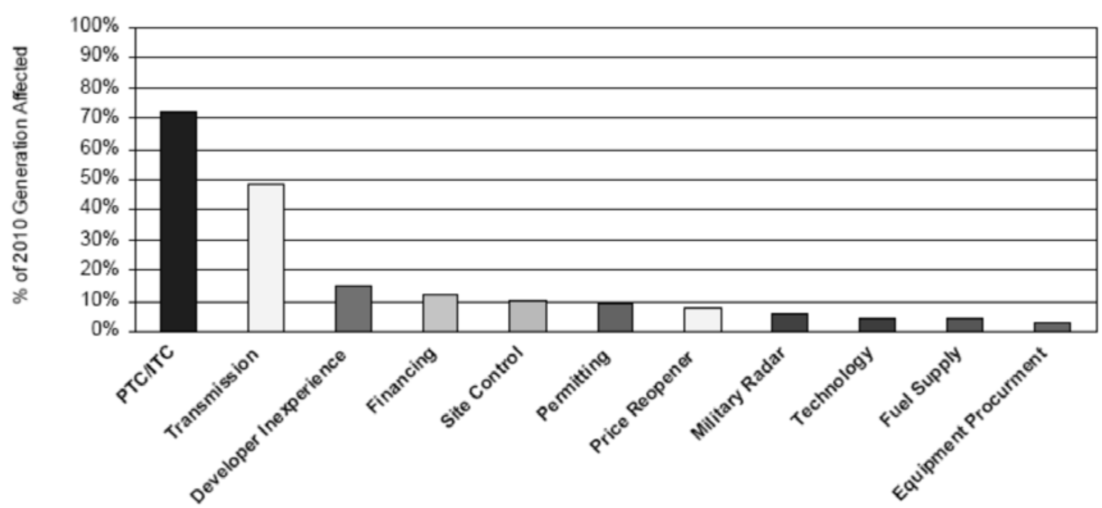


Figure 2 below details all of the major factors that, according to the CPUC, are barriers, or "risk factors, for renewable development in California. Despite identification of the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) as, by far, the "top risk factor" for renewables in California, wind power has not grown in this state even in years when the credit was available. By contrast, development of wind power in the rest of the nation has been remarkable. In 2007, over 5,200 megawatts of wind turbines were installed in the US, representing a six-fold growth over the past decade. In the same year, only about 60 megawatts of wind farms were built in California—and that was by a public utility that was not under the state's renewables mandate. Clearly, there is an urgent need to repair the program. This should not be difficult, especially since many of the factors causing problems are well known.

Less thoroughly examined has been the role of the state's own rules and regulations. For example, regulators have not imposed any monetary penalties on the IOUs despite their failure to meet their renewable energy targets year after year.

There are also complicated rules. The state renewable law runs over 40 pages and sets up a maze of conditions, exceptions, and funding accounts. The most important money account was intended to help pay for renewable energy using so-called Supplemental Energy Payments. Because the payments were conditioned upon availability of funds, investors in renewable energy did not consider this a reliable source of funding. None of the funds were ever paid out, and the support structure was cancelled.

Figure 2. Risk Factors for 2010 RPS Generation [4]



Fossil Fuels Win, Renewables Lose

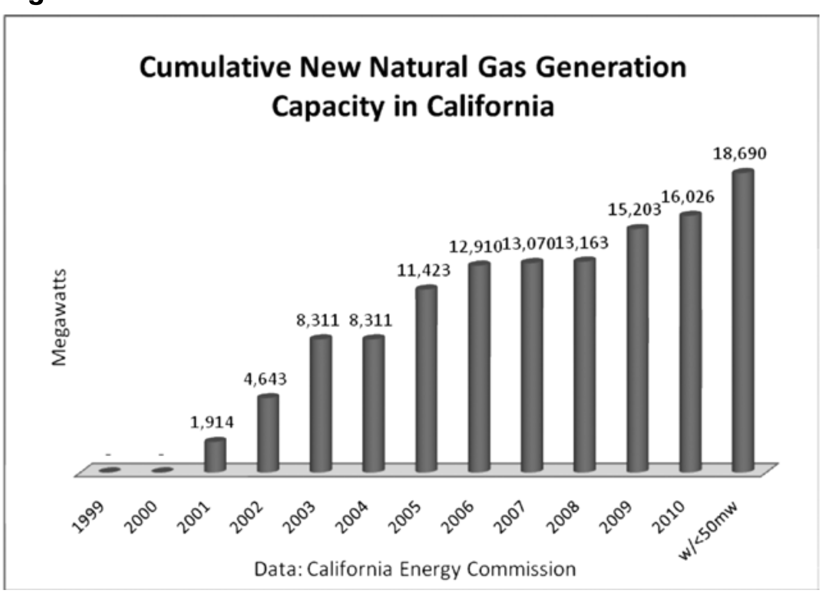
The failure to increase renewable energy is directly connected to the relentless march of new natural gas plants. This is mainly because natural gas is the next prioritized energy supply resource after renewables. In other words, renewables have to lose in order for natural gas to win. Even though renewables are nominally a higher priority, a competitive struggle for existence between natural gas and renewables is embedded directly into state policy—by design.

The regulatory process makes every renewables contract compete with natural gas power. This "competition" has an interesting twist. Regulators forecast natural gas fuel prices extending decades into the future, creating a fictitious price called the Market Price Referent. However, natural gas plants get an unfair advantage. No matter how high the price of natural gas goes up in the future, the higher cost just gets passed on to consumers. Cost recovery for natural gas plants is not bound by the natural gas price forecasts, and, skewing this "competition" even further, natural gas prices are calculated at discounted present value. On the other hand, the renewable developers *are bound* by the result of this invented competition. Not surprisingly, natural gas seems to win this game almost every time.

As a direct result of this failure to increase renewable energy, policymakers have come to assume that we "need" to build more natural gas power plants. Utility companies are only too happy to oblige and foster this impression, which is not surprising given that the other major product these utilities provide, in addition to electricity, is natural gas.

Moving to green energy will require reversing course. As the state slipped year-after-year on meeting renewable energy targets, a spree of construction since 1999 has resulted in major investment in new natural gas electric generation in California, at least $15 billion so far. Many of these plants replaced older, less efficient power plants, and for a time actually reduced consumption of natural gas fuel. However, this improved efficiency is undermined by the fact that while 7,500 megawatts of old plant capacity retired by 2008, over 18,000 megawatts have been built, or will be built, by the end of 2010.[5] The cumulative new natural gas generation added in California over the last decade is shown in Figure 3. Figure 3 shows only new natural gas plant construction. This is far less than the total natural gas plant capacity in the state, which exceeds 40,000 megawatts.

Figure 3.



The build-up of natural gas plants occurred just as the state was supposed to be implementing its renewables policy. But the usage rate of natural gas plants will need to decrease if clean energy policies are to achieve their goals. A 2003 study by Lawrence Berkeley National Laboratory (LBNL) looked at the effects of increasing renewables and reducing growth in energy demand on the future need for natural gas plants in California.[6] LBNL found that by 2030 the state would need to reduce natural gas plant capacity by 8,000 megawatts to meet the proposed requirement to get 33 percent of electricity from renewable energy. If aggressive energy efficiency policies slow the rate of growth in electricity demand, this could reduce the need for natural gas power plants by another 4,000 megawatts. The study did not consider the possibility of combining energy efficiency with renewables, but the state is actually in the process of adopting both these requirements.

The chart above shows California's existing natural gas plant capacity in April 2009 at 41,499 megawatts.[7] The LBNL study projected that if the state implements both the 33 percent renewables requirement and aggressive efficiency programs, then over 20,000 megawatts could be retired, more than the capacity of the 15,400 megawatts of aging OTC natural gas plants. Building any new natural gas capacity undermines California's green energy goals. Even repowering existing plants would amount to pushing aside the state's green energy targets.

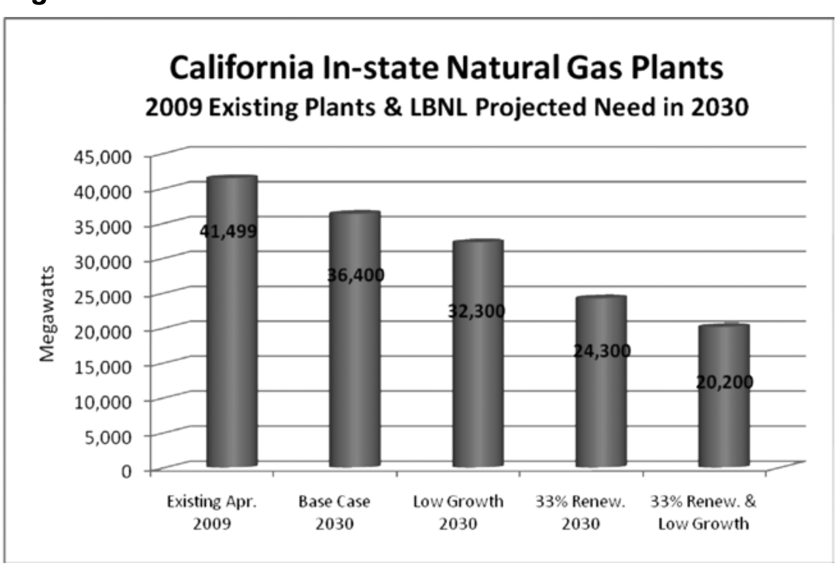
It is important to realize how much "padding" is placed into the LBNL projections. The report looks at the need for natural gas power plant capacity in 2030, a full decade beyond the 2020 renewable program policy target. This allows up to a full decade of delay in meeting these targets, and also accomodates an extra decade of growth in demand. The report made the following growth assumptions:

> "To address California transmission interconnections for the future, this study focused on the year 2030. By that time, California is forecast to experience:

- Population growth to over 50 million, an increase of 18 million over 30 years;
- Electricity peak demand of 80 G W, an increase of 28 GW from current [2003] levels, or an average annual peak demand growth of 1.5 percent."

More specifically to OTC natural gas power plants, a more recent study concludes that they can be easily taken off line over the next several years. In its 2008 report produced for the California Ocean Protection Council, ICF Jones & Stokes conclude that given their low usage, the shuttering of the OTC natural gas plants by 2015 could occur with no need for replacement generation capacity. The report's modeling indicates that "given sufficient time to react, the electric[8] industry could likely tolerate and compensate for mass OTC retirement at relatively modest costs to the ratepayer…the retirements could be compensated for with as little as $135 million in in-state transmission upgrades." The report goes on to conclude that, "…under all but the most extreme scenarios, more than enough power plants are expected to be operating in 2015 to more than compensate for any OTC plant retirements, with a projected 28 percent reserve margin of supply over demand in the Western half of North America."

Figure 4.



Even as green policy mandates are adopted, the rules and decisions continue to push relentlessly for more natural gas plants. Unfortunately, the playing field is unlevel to favor fossil fuels over the environment and public health. Most damage to human health, water resources, air quality and the global climate are not folded into the price that utility companies pay for electricity. However, the costs to human health and the environment are real, and consumers pay for them. Air pollution causes lost days of work, increases the cost of health care, adds to wear and tear on buildings, and causes billions of dollars in damage to crops every year. Destruction of ocean life reduces commercial opportunities and increases the cost of seafood. Much of the damage is unquantifiable. For example, it is difficult to estimate the burdens future generations will bear for climate change or the lack of resources that have been wasted.

The True Cost of Climate Change

Some of the damages caused by fossil fuel plants produce externalities that will increase utility bills as well. For example, climate change can lower snowpack, and this in turn reduces hydropower. To counter this risk, utility companies pay many millions of dollars for natural gas generators to be on call to provide backup power in years when hydro resources fall short.

Rising temperatures also increase use of air conditioning on ever hotter summer days, which calls for increased use of natural gas to meet peak energy demand. Air conditioning in California consumes up to 14,400 megawatts of power during the summer, as much as one-third of peak demand, and is the main reason why electricity demand soars during the summer season. Air conditioners that use less electricity, combined with better insulation and windows, lighter colored roofing, and strategically placed shade trees can substantially reduce electricity demand in summer months.

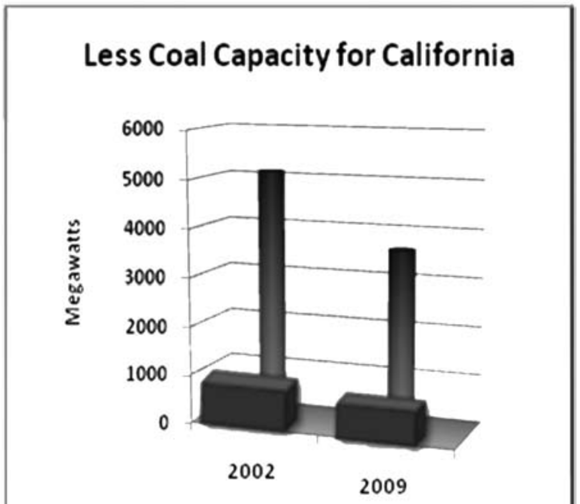
The aging coastal natural gas plants operate almost exclusively to meet this summer demand. These plants are mostly idle the rest of the year. The 15,000 megawatts of aging plant capacity nearly matches the peak air conditioning demand in California. Thus, every megawatt of air conditioning efficiency and conservation measures could directly remove the need for a megawatt provided by OTC natural gas power plants. The California Energy Commission and CPUC have recognized in the 2007 Integrated Energy Policy Report that widespread adoption of the most efficient appliances available can reduce peak demand by 46 percent in homes and 13 percent in industrial buildings.[9]

Leveling the playing field between green energy and new natural gas plants will require looking at the total cost of both paths. If the damage caused by natural gas power plants is accounted for, then this will change the price comparison. Such a process is called "internalization of externalities," meaning that the costs normally carried by society is imposed on the product's price, in this case the cost of power from the plant itself. The operator would be held economically responsible for damage that is caused by the plant. Already, the California Public Utilities Commission requires that utility companies place a virtual "carbon adder" of up to $24 per ton when evaluating renewable contracts. However, there is evidence that this might not be sufficient to account for the real harm from climate change, which could be $80 per ton or more.[10]

2. Natural Gas as California's Primary Source of Electricity

The environmental problems with coal have led to the idea that natural gas should be the "transition fuel" that paves the way to a greener energy future. In the U.S. as a whole, natural gas has increased its role in the generation of electricity over the past half century. Natural gas sources generate 21 percent of the nation's electricity output, while coal accounts for approximately 50 percent. In California, however, coal, mostly imported from out of state, provides only 16 percent of electricity used when measured in kilowatt-hours.[11]

Figure 5.



data: California Energy Commission

As of 2007, state law forbids new long term contracts for power sources with carbon emissions higher than a combined cycle natural gas power plant.[12] This means that coal will be phased out over the next two decades as existing contracts expire. This is on top of the major reduction in use of coal power since 2002.[13] Nearly all of this coal power is imported from plants in other western states; in-state use of coal in California is negligible.

In 2004, natural gas, liquified petroleum gas, and refinery gas were responsible for 142 million metric tons of CO2 emissions.[14] This was nearly 36 percent of greenhouse gas emissions from fossil fuel combustion in California. Coal combustion from power used in California generated about 60 million metric tons of CO2 emissions, far less than natural gas.

Despite its clean reputation, natural gas production has historically been closely tied to the extraction of other less clean fuels. A significant portion is produced as "associated gas" from oil wells,[15] while the rest comes in the form of unassociated natural gas—natural gas deposits that do not contain crude oil. Increasingly, natural gas is being produced from unconventional sources, such as coal beds and impermeable shales, using methods that have significant environmental costs. The process of extraction can degrade watersheds and aquifers. Substantial production is occurring and is planned from sensitive areas of the Rocky Mountain states. In addition, there is a renewed push to open-up more areas offshore of the U.S. for drilling. All of this comes with increased environmental risk and increased cost.

Natural gas can also be imported to California as liquefied natural gas (LNG). LNG is natural gas that has been chilled to minus 260 degrees, at which point it condenses into liquid form. As a liquid, it can be loaded onto specially designed supertankers, and shipped overseas to receiving terminals. There is one operational LNG import terminal owned by Sempra Energy in Baja California, Mexico that is interconnected to the California natural gas pipeline system. More LNG terminals have been proposed. However, abundant North American natural gas production and low domestic natural gas prices have dampened the drive to build more LNG receiving terminals on the West Coast.

LNG is significantly more GHG-intensive than domestic natural gas. The reasons for the higher GHG intensity include the energy necessary to liquefy the natural gas, to transport it across the Pacific in supertankers, and to regassify the LNG for injection into California's pipeline system.

California's Mandate: Dramatically Reduce Natural Gas Consumption

This report proposes a strategy for addressing one facet of reducing California's reliance on natural gas: phasing out the state's fleet of aging OTC natural gas power plants without constructing new fossil fuel plants. There are a number of reasons for focusing on old natural gas plants. They have relatively low efficiency due to their age and the fact that they only operate a fraction of the time, producing only 4 percent of the state's electricity supply. The California Energy Commission has proposed full retirement of all these power plants by 2012, but there are serious risks that an overly aggressive schedule of retirement could result in hasty attempts to replace all or most of these plants with new natural gas plants. This approach would commit the state to decades of continued reliance on natural gas for meeting electric power demand needs and would contradict the mandates for renewable energy and climate protection.

Much of the problem of inefficient natural gas use has already been addressed. A major construction effort over the last ten years has resulted in over 16,000 megawatts of new natural gas power plants in California, and the retirement of nearly 8,000 megawatts of old plants.[16] The newly constructed plants include many "baseload" plants that provide power around the clock. This type of generator has seen the most dramatic efficiency improvements, and the result of the replacement program has been a reduction in natural gas consumption for power generation between 2001 and 2006.[17] Another important strategy for reducing natural gas consumption by baseload plants is combined heat and power, also called "cogeneration," where the waste heat from electricity generation is recycled for industrial or commercial use.

This report will account for the costs of environmental damage from California's use of natural gas to produce electricity, and by doing so put renewables on a more level economic evaluation. The limitation of this method should be kept in mind, as great environmental harm cannot be evaluated by economic methods alone. Many of the costs to current and future generations cannot be evaluated by looking at monetary costs alone.

This report will focus on the aging OTC natural gas plants that provide peak energy supplies, rather than the baseload plants. These aging plants pose a number of problems:

- They use more fuel than modern plants per kilowatt-hour generated.
- They have higher operation and maintenance expense.
- They break down more frequently than new plants and are at risk for being unavailable when needed.
- They emit air pollutants—often in neighborhoods with economically disadvantaged populations.
- They utilize huge quantities of water and destroy sea life.

The California State Water Resources Control Board (SWRCB) is considering policy options for minimizing one type of environmental damage from the state's aging power plants. These plants use vast amounts of seawater for a "once through cooling" technology that is destructive to sea life. In its evaluation of alternative courses of action, SWRCB has identified preservation of marine resources as a high priority. This report also cites the damage caused by these plants beyond the marine environment and proposes alternate solutions that reduce reliance on natural gas power plants.

This report will show how to reconcile the needs of the electric power grid with the needs of the climate, marine resources, and public health. It will take a different approach from other reports on this topic. In most cases, the utilities, California's Independent System Operator (CAISO), as well as staff and consultant reports have considered the implementation of the state's clean energy policies as an uncontrollable variable, purely subject to "market forces" or other contingencies outside the control of state agencies or utilities.

In reality, decisions made by SWRCB, California Public Utilities Commission, Air Resources Board, California Energy Commission, and others, can serve as direct inputs to help create the needed change. Accounting for environmental damages when calculating the cost of electricity generation and conservation options will directly affect market and regulatory choices for how power supply needs will be met in the future. This in turn can help make development of renewable energy and increased efficiency more cost effective than they otherwise would appear.

This following analysis examines the environmental and economic costs and benefits of replacing or repowering aging OTC natural gas plants in two different ways:

- Scenario 1, "Fossil Replacement," repowering plants at their current sites with less environmentally harmful combustions and closed-cycle cooling.
- Scenario 2, "Green Energy Replacement," conforming to California's adopted laws and policies for increasing renewables, and reducing greenhouse gas emissions and other pollutants. This scenario results in a greatly reduced number of natural gas fired units.

3. Properties of Aging Natural Gas Power Plants

Natural gas is often promoted as a flexible and efficient power source. While coal and nuclear power plants only convert about a third of the energy in fuel to electricity, the best modern natural gas "combined cycle" electric generators can achieve nominal efficiencies of up to 60 percent, and in practice range from 45 to 55 percent.[18] These combined cycle systems recycle the waste steam from a high temperature turbine into lower temperature boiler-powered generators.

Natural gas can also be used in a "simple cycle" turbine or boiler to ramp electric generators up and down rapidly in response to changing needs of customers. This is far less efficient than combined cycle systems, with efficiency closer to a nuclear or coal plant. In general, all power plants operated by the action of heat—whether coal, nuclear or natural gas—must be run at relatively stable output, or they lose much of their efficiency. Even combined cycle units lose much of their efficiency when they are frequently cycled on and off, as they will then usually function in a "simple cycle" mode. [19] Cycling the turbines and generators on and off also tends to age the equipment rapidly and increases maintenance costs. This is how the state's fleet of aging natural gas power plants currently operates.

Thus, there is a real choice with natural gas power plants: they can either be flexible or they can be efficient, but not both at the same time.

Natural gas power plants go through a typical aging process. When they are new, for the first decade or so, they operate as baseload plants. As their efficiency falls, and as newer and more efficient plants come on line, the middle-aged plant will be moved over to more variable operation, ramping up and down in power output as daily demand changes. An aging plant, one that is 20, 30 or more years old, will generally be used least of all, be cycled on and off, and eventually may be operated only a few hours a year. The low efficiency, low capacity utilization, and greater need for repairs, can make these aging plants much more expensive to operate than a baseload plant.   However, a new power plant that supplies peaking energy needs may be even more expensive, since the capital costs are higher. The California Energy Commission estimates that a new power plant operated in a similar manner to the less utilized aging power plants—between five and nine percent capacity— would cost from 35 to 64 cents per kilowatt-hour. [20]

Aging natural gas-fired power plants can provide a considerable portion of the state's electric power capacity, but this is only during the relatively short hours of peak demand. These 17 plants, all built more than thirty years ago, continue to operate—despite their inefficiency and damage to air and marine environment—because they are sources of "high value" peak and load-following electricity for electric companies. However, the cost of operating these power plants is compounded by social and environmental damage, some of which is not included in the electric bill:

- Many plants are located near high-density populations and emit substantial pollution, leading to asthma and other respiratory ailments. Even though pollution has been reduced in recent years either by installing modern control technology or limiting generation, aging natural gas plants still emit particulate matter, volatile organic compounds, carbon monoxide and nitrogen oxide in the local area and add to regional pollution in air basins that fail to attain federal air quality standards. This problem is exacerbated because the plants mostly operate during hot summer days when pollution from other sources is already high.
- Global warming, fed by continued greenhouse gas emissions, could devastate California's economy. The California Air Resources Board recognizes this in their plan for implementing the state's greenhouse gas reduction law (AB32), stating, "…the overall savings from improved efficiency and developing alternatives to petroleum will, on the whole, outweigh the costs. The potential costs of implementing the (AB32) Plan pale beside the cost of doing nothing."[21]
- The higher than average amount of fuel required to power many of these plants translates into wasted natural gas. This is referred to as a "high heat rate," meaning that more heat is required to produce a kilowatt-hour of electricity. It also means more environmental damage to produce the energy.
- A majority of these plants are coastal and use seawater for cooling. Once-through cooling (OTC) uses huge volumes of water and

inflicts considerable damage on the surrounding marine environment by killing marine species.

Recognizing these problems, the California Energy Commission has recommended that 15,000 megawatts of aging plants be retired by 2012, [22] while the State Water Resources Control Board is currently considering a policy that would "protect marine and estuarine life from the impacts of once-through cooling without disrupting the critical needs of the State's electrical generation and transmission system."[23] Currently, a portion of this capacity is planned for replacement either with new natural gas power plants or by repowering the aging plants with new technology. Sometimes replacing an older plant with a modern plant will reduce fuel consumption significantly per kilowatt-hour generated, but this is not true in all cases. In fact, new plants may increase fuel consumed and carbon emissions—precisely because greater efficiency will make the plants more competitive over more hours of the year, particularly if external costs are not included in dispatch decisions.

Out of the 17 plants examined in this report, nearly half either operate at a similar level of efficiency as a modern plant, or run relatively few hours a year, or both. Replacing these aging plants with modern natural gas plants is difficult to justify, since they will save little if any fuel even under the most optimistic assumptions, and will fail to significantly reduce greenhouse gas emissions or other pollutants. The capital cost of a new plant will be considerably higher than the aging plants. Using the California Energy Commission values of $1,000 per kilowatt for installing new combustion turbines, it will cost at least $15 billion to replace all the power plants.

However, this is just a "down payment" on the much higher lifecycle costs of the plants, which includes fuel, operation and maintenance, and return on investment. Combined, these costs could be more than six times the original cost of the plant. Replacing all the aging plants with new natural gas plants could exceed $100 billion if fuel is included, especially if natural gas prices are higher than expected, or if the plants have higher utilization than the current ones do. In addition, there will continue to be significant environmental costs, particularly local air pollution and climate change. These expenses raise the question of whether other options might be more cost effective.


smud.org

4. California's Electric Power Resources

There are huge resources available to the state's electric power grid, including generation from natural gas, nuclear, hydroelectric and renewable power sources. For purposes of grid reliability, natural gas and some kinds of hydroelectric generation are "dispatchable," meaning they can be ramped up and down in a controlled manner to respond to changing needs for energy. A power plant operating in this manner is called "load following." Solar and wind are said to be "intermittent," generating power according to when the sun shines or the wind blows.

The table below shows power supplies from different sources, including the aging power plants currently in operation, adjusted for a reliability factor called "effective load carrying capacity" (ELCC): [24]

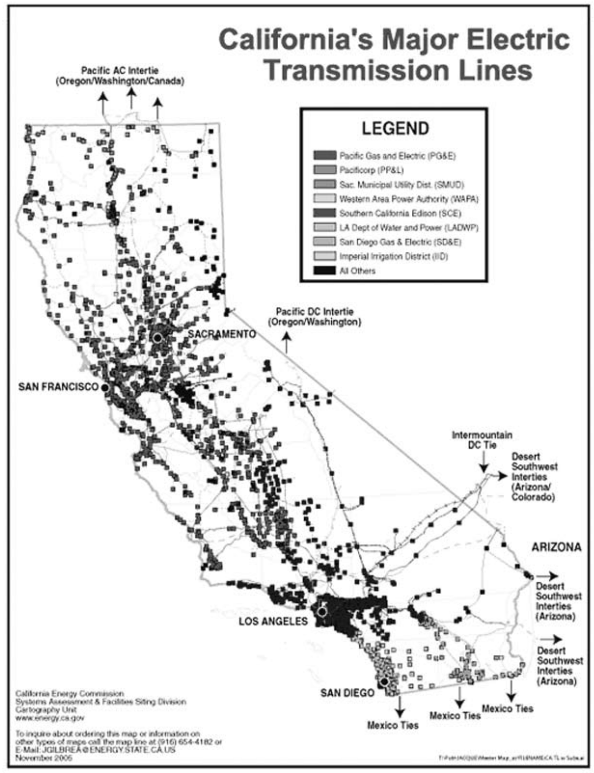
Table 2: California In-State Generation Resources

	Capacity	elcc	reliable
	mw		mw
NaturalGas [25]	41,499	100%	41,499
Coal	400	100%	400
Nuclear	4,472	100%	4,472
Hydro	10,420	100%	10,420
Pumped Storage [26]	4,132	100%	4,132
Biofuel	1,107	100%	1107
Geothermal	1,827	100%	1,827
Solar	357	60%	214
Wind	2,706	25%	676
Total Database	**66,920**		**64,474**

Conventional power sources such as natural gas, nuclear and hydroelectricity are considered to count 100 percent of their capacity toward reliability needs, and thus are rated with 100 percent Effective Load Carrying Capacity (ELCC). About half of the state's renewable power is wind, which is quite variable and has a 25 percent ELCC in California, while solar thermal generation in the desert has a 60 percent ELCC. The Effective Load Carrying Capacity is calculated by measuring the reliable output of the wind or solar plants during the limited hours of peak energy demand.

The total reliable generation resource above, of 64 thousand megawatts, exceeds the CAISO summer heat storm peak demand needs in 2006, which was just over 60 thousand megawatts.[27] That heat storm represented an event expected less than once in 30 years, a level of demand that is higher than the normal long term growth trend line.[28] Current state reliability criteria only require demand projections for a 1 in 2 year event, plus a margin of 15 to 17 percent for extra security. It is noteworthy that these planning criteria for electric system resources were more than sufficient to meet the needs for the extraordinary 2006 event

Figure 6



In addition to the in-state power plants considered above, there are several other significant resources available to meet the demand for electricity. For example, Investor Owned Utilities (IOUs) are required by the California Public Utilities Commission to obtain 5 percent of peak energy needs from peak demand reduction programs, called Demand Response. Demand Response is a voluntary program where utilities have contracts with their large power customers to cut back their usage when the system is under strain, and the customers are compensated for this cutback. While the utilities have fallen short of meeting this target, other programs allowing the utility to curtail their customers' energy usage during power emergencies—called Interruptible Load—has more than picked up the slack. In all, 236,195 customer "Service Accounts" participated in the demand reduction programs offered by the Investor Owned Utilities. Another resource is the wide assortment of small customer-owned generation, particularly Backup Generators ("BUGS"), and rooftop solar photovoltaics (PV).

Finally, there are several major power transmission lines that bring in electricity from out-of-state.[29] Import capacity includes 7,900 megawatts from the Pacific Northwest, 1,900 megawatts from Utah, 7,500 megawatts from the Desert Southwest, and 800 megawatts from Baja region of Mexico, for a total of over 18,000 megawatts.[30]

Table 3: Total Resources Available to California Electric Grid

Resource	mw
Instate Generation	64,474
Transmission Import	18,100
BUGS Database [31]	3,492
Peak Demand Resource (DR/IL) [32]	2,669
Rooftop Solar	120
Total All	**88,855**

If all these resources are included, the power capacity for the state is near a staggering 89,000 megawatts, about 40 percent higher than has ever been recorded as a peak demand.[33]

The chart below helps to picture what a "typical" day of demand looks like for the California ISO grid.[34] During the spring and fall, daily electricity demand peaks at about 30 thousand megawatts, while in the summer it can rise in the late afternoon to 40 thousand megawatts or more. After the peak demand falls over a period of 10 to 12 hours to a low point in the early morning before dawn, the demand begins to rise again. Note that the on-call resources available were over 11,000 megawatts higher than what was needed.

Figure 7: California ISO Forecast and Demand for October 7, 2009

5. Overview of Aging Power Plants

Seventeen large natural gas plants have been selected for this analysis, with combined capacity of 15,400 megawatts. All were built before 1980, and have operational steam turbine units. The study group is based on the California Energy Commission (CEC) 2004 report on aging power plants, with minor updates.[35] Only steam turbine generators are included, not smaller simple-cycle units, as the cost and impacts of these smaller units are negligible. Also omitted are units, such as Humboldt Bay 1 and 2, that were originally powered by steam turbines but have been or will be repowered with more efficient technology.

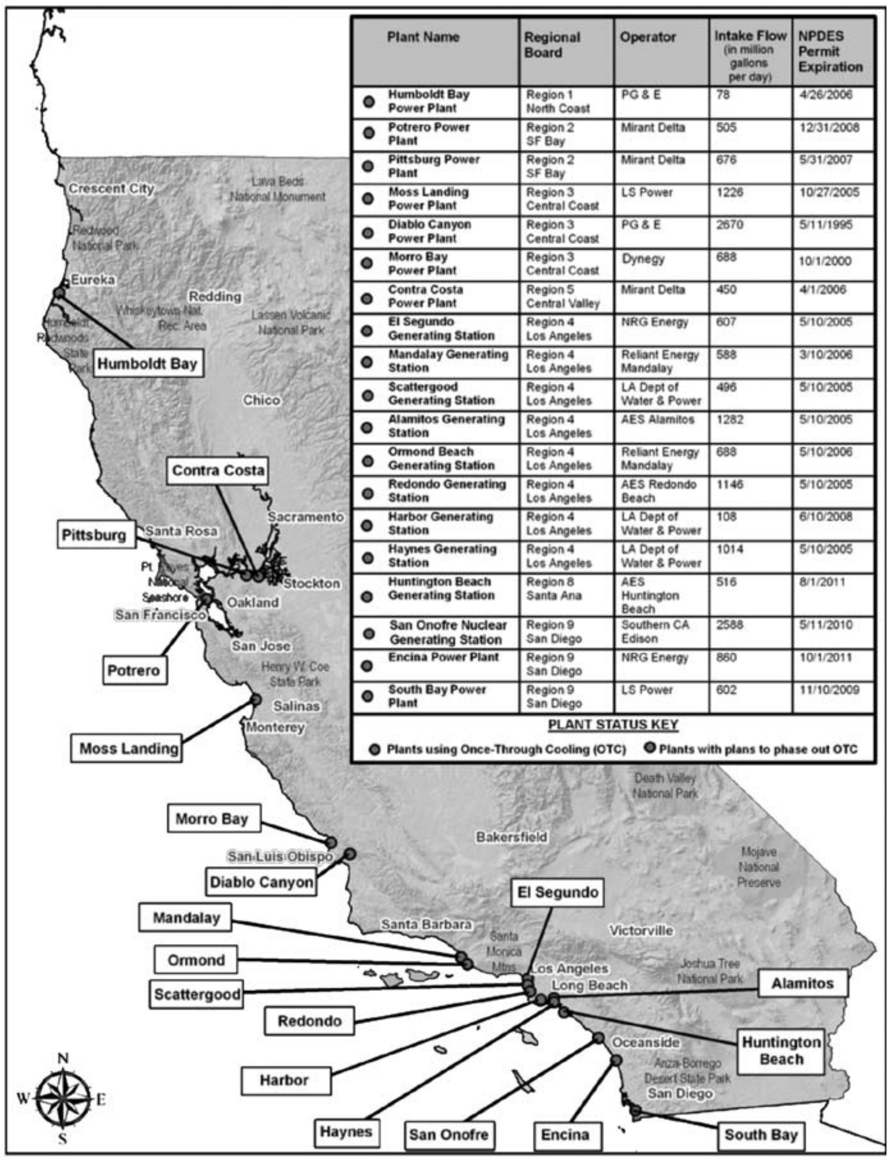
When referring to a "plant" only the units in Table 1 are included, although the plant may house other generators. Since shutdown of the South Bay Power Plant is likely, it is omitted from the study group.[36] All plants in the study group have no definite plans for retirement at present. The CEC has called for retirement of all these plants by 2012, although they do not have the authority to compel closure. Once through cooling (OTC) is used at generators totaling 13,673 megawatts of capacity.

Because of their age—most have been online for about half a century—some of these power plants use fuel inefficiently compared to modern turbines and experience higher forced outage rates. Heat rates for modern natural gas peak power plants vary between 9,200 and 10,500 btu/kWh, whereas the average heat rate of the study group in 2005 was 11,202 btu / kWh.[37]

The majority of these plants are load-following, operating primarily during the summer months. The degree of utilization is referred to as "capacity factor," expressed as a percentage. The percentage is a product of both 1) the fraction of maximum rated power that the plant actually generates, as well as 2) how many hours out of the year it operates. A plant that generates electricity at 100 percent of its rated power output, 100 percent of the time, would have a 100 percent capacity factor. A plant operating at 20 percent capacity factor might—to illustrate two possible examples—run at full capacity 20 percent of the time, or run at an average of 40 percent capacity half the time. Most of the aging plants operate relatively few hours per year, primarily during times of peak energy demand in the sumer.

These 17 plants are also considered in the 2008 Once-Through Cooling (OTC) Reliability Study

Figure 8: Aging Natural Gas and Nuclear Power Plants.



Plant Name	Regional Board	Operator	Intake Flow (in million gallons per day)	NPDES Permit Expiration
Humboldt Bay Power Plant	Region 1 North Coast	PG & E	78	4/26/2006
Potrero Power Plant	Region 2 SF Bay	Mirant Delta	505	12/31/2008
Pittsburg Power Plant	Region 2 SF Bay	Mirant Delta	676	5/31/2007
Moss Landing Power Plant	Region 3 Central Coast	LS Power	1226	10/27/2005
Diablo Canyon Power Plant	Region 3 Central Coast	PG & E	2670	5/11/1995
Morro Bay Power Plant	Region 3 Central Coast	Dynegy	688	10/1/2000
Contra Costa Power Plant	Region 5 Central Valley	Mirant Delta	450	4/1/2006
El Segundo Generating Station	Region 4 Los Angeles	NRG Energy	607	5/10/2005
Mandalay Generating Station	Region 4 Los Angeles	Reliant Energy Mandalay	588	3/10/2006
Scattergood Generating Station	Region 4 Los Angeles	LA Dept of Water & Power	496	5/10/2005
Alamitos Generating Station	Region 4 Los Angeles	AES Alamitos	1282	5/10/2005
Ormond Beach Generating Station	Region 4 Los Angeles	Reliant Energy Mandalay	688	5/10/2006
Redondo Generating Station	Region 4 Los Angeles	AES Redondo Beach	1146	5/10/2005
Harbor Generating Station	Region 4 Los Angeles	LA Dept of Water & Power	108	6/10/2008
Haynes Generating Station	Region 4 Los Angeles	LA Dept of Water & Power	1014	5/10/2005
Huntington Beach Generating Station	Region 8 Santa Ana	AES Huntington Beach	516	8/1/2011
San Onofre Nuclear Generating Station	Region 9 San Diego	Southern CA Edison	2588	5/11/2010
Encina Power Plant	Region 9 San Diego	NRG Energy	860	10/1/2011
South Bay Power Plant	Region 9 San Diego	LS Power	602	11/10/2009

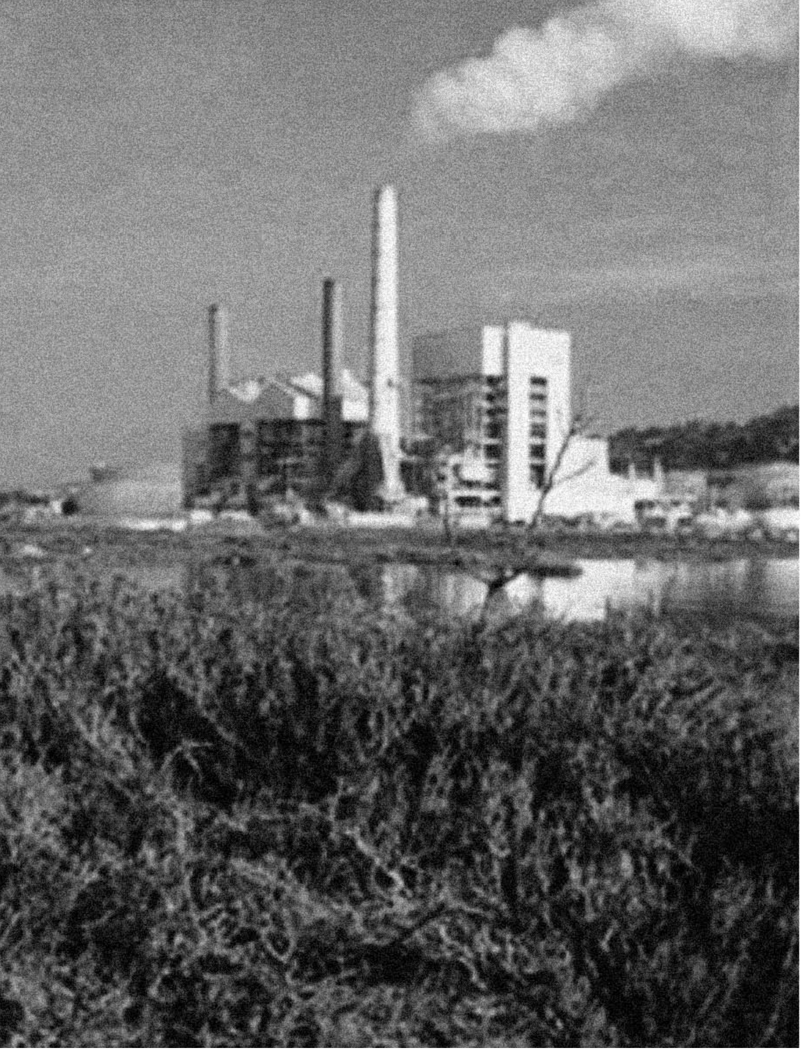
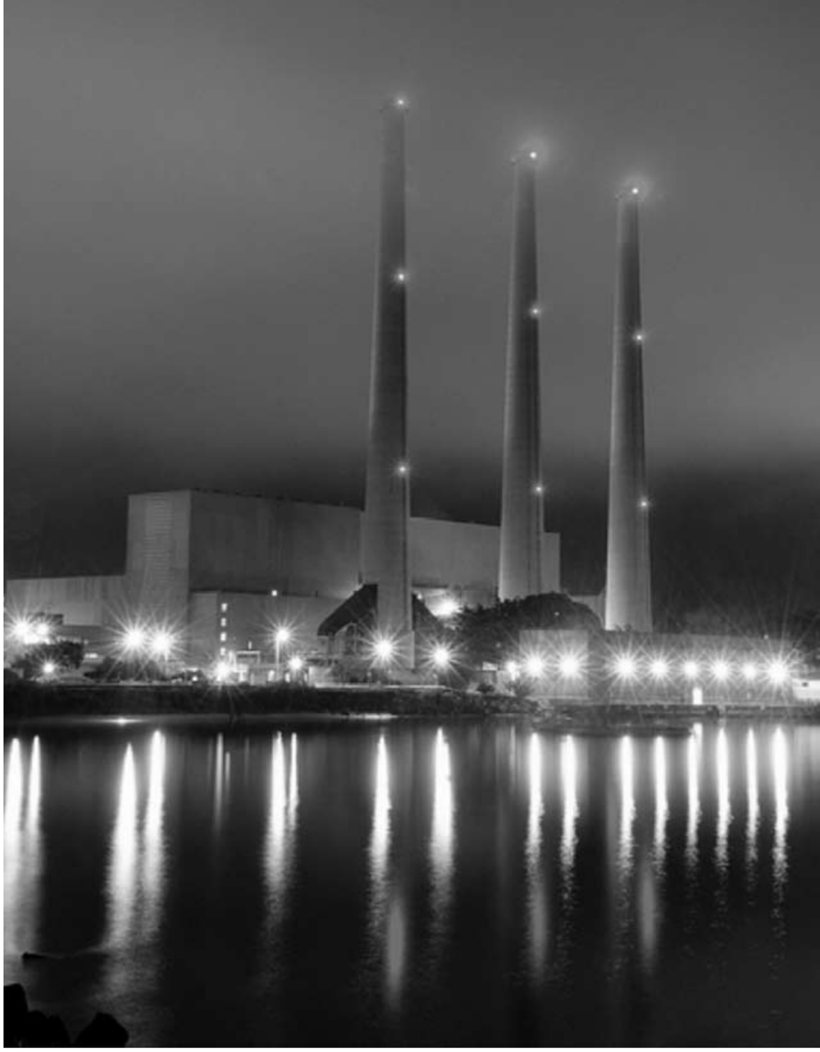
PLANT STATUS KEY

Plants using Once-Through Cooling (OTC)   Plants with plans to phase out OTC

Map: California Coastkeeper Alliance

prepared for the State Water Resources Control Board (SWRCB). This study reports significantly higher capacity factors for a number of plants during 2001; however, that year was characterized by a failed "deregulation" scheme that resulted in many generators going off-line when they could not recoup the skyrocketing cost of natural gas fuel.[38] Due to the unavailability of many power plants, a significant feature of that year's so-called "energy crisis" was that low efficiency power plants—such as the ones considered in this report—were being called on to provide for a larger share of the power supply. This, combined with natural gas prices elevated in part due to market manipulation, increased the cost of generating power. Including the historically unique 2001 data in the performance record exaggerates the actual need for these plants in terms of energy (kilowatt-hours) supplied. Similarly, failing to look at the full range of available options and policies will exaggerate the capacity (megawatts) needs for natural gas plants.

There is one function that these power plants provide that is particularly significant. Due to their ability to ramp up and down to meet the changing needs for power, and their proximity to major population centers, these plants contribute to the reliability of the electrical grid, especially in transmission constrained areas and during power emergencies. In order to protect the power supply from the disruptions that occurred during 2000–2001, certain power plants were placed under contract with the California Independent Service Operator (CAISO) to provide power when needed for reliability purposes. This has the additional benefit of limiting options for price manipulation under times of market stress. These obligations are placed on certain strategically important power plants, and are called "Reliability-Must-Run" contracts. The CAISO gave Reliability Must Run (RMR) designations to six of the nineteen aging plants listed above, although all but one was released from RMR status in 2008.[39]

6. Internal Economic Costs to Owners of Aging Plants

Owners of aging power plants pay fixed costs simply to keep the plants operational, and costs that vary with the amount of electricity generated. Examples of fixed costs include property taxes, insurance, and repayment of debt obligations. Variable costs include repairs and fuel. Because every plant in the study group is more than 25 years old, the financing necessary for initial capital investments has been either fully or largely repaid. However, the plants do retain some asset value and are expected to provide a rate of return to investors. The remaining fixed costs, such as capital improvement incurred to keep the unit operational, insurance, taxes, etc., comprise the annual fixed-revenue requirement (AFRR).

In general, companies do not release these costs, and so we must extrapolate from the AFRRs of RMR-designated units, which are public record.

There is a wide variation in costs, although higher total generation correlates roughly with lower AFRR per megawatt-hour. If the fixed cost to own and maintain the plant each year can be spread out over more electricity sales, this lowers the rate charged for each unit of energy. On the other hand, plants that sell very little electricity may need to charge very high energy rates to recover costs. The range is quite large, with $18.53 per megawatt-hour (MWh) at the lower end, and $135.06/MWh ($1.35 per kilowatt-hour) or even higher possible for plants with very low capacity factors. Model projections for all the other plants extrapolate from the existing plants, with generally lower rates per MWh for plants with higher utilization (capacity factor), and higher rates for plants with lower utilization. The average over the group of plants is $64.55/MWh (6.45 cents/kwh), with total annual fixed revenue requirement of $785,896,000.

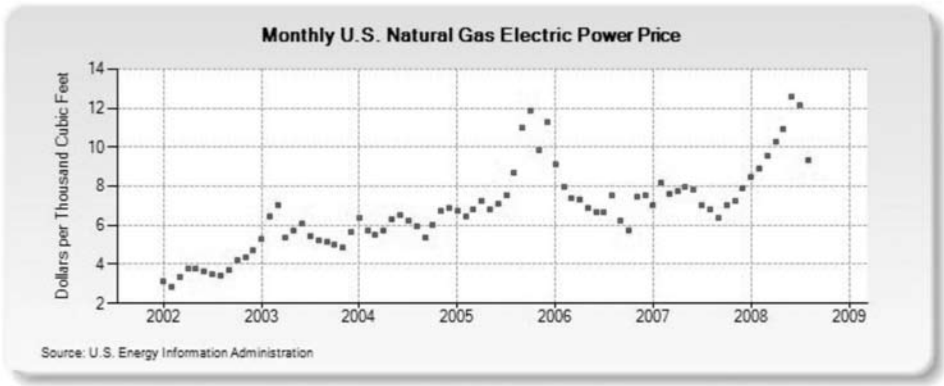
The fixed cost is generally half or more of the total cost to generate electricity, with the balance being "variable costs." These include expenses such as workers' salaries, maintaining the generators, and others related to keeping the plant doors open. These are different than variable costs, which are those related to how much the plant is actually operated. Variable costs include fuel, and operations and maintenance (O&M). In its report on aging power plants, the CEC estimates variable O&M costs for these plants to be around $2-3 per MWh, totaling $24.3–$36.5 million for all study group plants in 2005.[43] However, the Energy Commission's newer report on levelized cost of power plants gives a figure about ten times higher at $26 per MWh for simple cycle turbines. If this higher figure is accepted, then the variable O&M expense rises to $316 million per year. This higher O&M cost is not incorporated in the standard model used by the CPUC in evaluating the Market Price Referent, the measuring stick used to determine if renewable projects are competitive with conventional power supplies. This represents an important bias in the Market Price Referent model that tends to understate the value of renewables, particularly those that provide power during hours of peak demand, such as solar energy systems.

Fuel represents by far the largest expense of operating these power plants, and the annual cost of fuel depends on the amount of fuel consumed as well as the price of natural gas, which varies from year to year. For 2005, the 133,117,687 million British thermal units (MMbtu) used by these plants is estimated to have cost $867 million, assuming a price of $6.31 per thousand cubic feet.[44] This annual cost will tend to increase in the future if natural gas prices increase, as they have for most of the past half century.

Table 5: Selected Power Plant Annual Fixed Revenue Requirements

Plant	AFRR (mil $)[40]	Net Generation 2005 (MWh)[41]	AFRR per MWh
Alamitos	$52.465	1,311,102	$40.02
Contra Costa	$44.709	331,036	$135.06
Encina	$45.352	1,864,797	$24.32
Huntington Beach[42]	$28.800	1,554,597	$18.53
Potrero	$17.054	385,621	$44.22
Pittsburg	$75.690	652,862	$115.94

Figure 9



Fuel prices in the latter part of 2008 and early 2009 dropped dramatically, which illustrates the great price volatility of natural gas. Historical data going back half a century shows natural gas nearly doubling in price in an average ten year period. Thus, one would expect that a decade that began with $2 natural gas would end up at about $4. This appears to be what is currently happening. It is reasonable to expect that the higher prices seen over the past several years are a foreshadowing of the coming decades, and this is in line with projections by the state and federal governments.

7. Air Pollution, Climate & Public Health Costs of Aging Power Plants

Pollution is the first of two major "external costs" associated with these aging power plants. Natural gas plants, even those with pollution reduction technology, emit substantial amounts of nitrogen oxides (NOx), carbon dioxide (CO_2), and particulates (PM). Sulfur dioxide emissions are negligible. This section quantifies the health and environmental impacts of these emissions.

NOx emissions react with the atmosphere to form ozone, particulates, and acid rain. Ozone and particulates contribute to respiratory ailments and other human health impacts, including premature death. Acid rain erodes structures, damages crops and pollutes aquatic systems. Because effects of these pollutants are localized, estimates for one area may not accurately reflect conditions at another site. The assignment of monetary damages to health impacts is controversial and not standardized, particularly the Value of Statistical Life (VSL) used to calculate damages from premature death. The EPA estimates the cost of NOx emissions at $1,667–$6,336 per ton for health, visibility, and ecological damages. The EPA uses a VSL of $6.7 million, and assumes for the upper estimate that ozone does contribute to premature mortality.[45] Using EPA figures, total annual damages from the NOx emissions of all power plants is $1.3–$4.9 million.

The aging plant's average NOx emission rate is 0.28 pounds per MWh, but the range is quite large: between 0.05 and 3.5 pounds per MWh—a 70-fold difference. Two plants, Humboldt and Coolwater, have such high emission rates that they double the NOx for the entire group. The Energy Commission reports that modern combustion turbines emit 0.09 pounds per MWh. NOx contributions from California's aging power plants represent a small portion of regional NOx emissions, ranging from 0.1 percent for Moss Landing to a high of 3.7 percent for Humboldt. However, those who live in close proximity to the plant can get much higher exposure than are reflected in the air basin percentages.

Global warming is damage caused by greenhouse gas emissions; however there is uncertainty in predictions about its effects on future climate. The Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment reported an average in peer-reviewed studies of $12 of damage per metric ton of CO2, the most prevalent greenhouse gas.[46] The range was quite large, from a low of $10 per ton to a high of $95. While most researchers have given figures near the lower end of this range, Sir Nicholas Stern found a damage cost of $80 per ton. With these values, greenhouse gas damage from the aging plants in 2005 is between $100 million and $667 million.

This range, however, contains factors that minimize the cost of damage—especially on the low end. IPCC notes that "It is very likely that globally aggregated figures underestimate the damage costs because they cannot include many non-quantifiable impacts."[47] IPCC states that these damages are likely to increase over time, and those global averages tend to understate regional damages that "will be significantly larger."[48]

Another major factor in estimating the cost of damages from climate change is more arcane, but perhaps much more important. A common practice in modern business is to have all costs "discounted" to present dollars, meaning that future costs are considered to be worth much less than current costs. This is only partly due to the effect of decreased value of future dollars due to inflation. It is much more related to the assumption that money borrowed or loaned out today will accrue interest or profit over time.

The "discounted dollar world" is rather like looking through a telescope backwards, so that things in the distant future look tiny. Each year that you look into the future shrinks the dollar by a fixed percentage, called the "discount rate." A discount rate of 5 percent means that each year that you move a dollar into the future will reduce its "value" by 5 percent. This method is helpful when making choices between present investments; however it does not reflect what things will really cost in the future. Future expenses will have to be paid out in future full-value dollars, rather than the artificially "discounted" shrinking dollars in the accountant's calculation.

The distortion caused by discounting future dollars can be quite severe, especially over decades or centuries, as Table 6 shows.

The "discounted" column shows how rapidly $100 shrinks in size through the application of a discount

Table 6: The Shrinking Effect of Present Value

Discounted Value vs. Inflation		
rate:	discounted 5%	Inflation 2.5%
year		
1	$100.00	$100.00
10	$63.02	$79.62
20	$37.74	$61.81
30	$22.59	$47.99
40	$13.53	$37.25
50	$8.10	$28.92
60	$4.85	$22.45
70	$2.90	$17.43
80	$1.74	$13.53
90	$1.04	$10.51
100	$0.62	$8.16

rate of 5 percent per year, especially when compared to an inflation rate of 2.5 percent. After 30 years the discounted $100 is worth less than half of the merely inflated version. After 90 years, inflation has shrunk the $100 to 1/10th of its value: $10.51. But the same original $100 discounted at 5 percent per year is only worth $1.04 by the end of this century.

This illustrates how the method of discounting can shrink money over long periods of time. The problem becomes acute when we are looking at very big, very long term problems like global warming. There are real questions as to whether this is even a reasonable—or ethical—tool in such a case. For example, if global warming causes $1 trillion in damages in the year 2100, this will appear in the current damage estimates as worth 100 times less, and damages in 300 years will be considered as worth a million times less than the same damage today.

An ethical question is whether we have the right to consider vast damages to future generations as gradually moving towards worthless as they are further removed from our own time. The Stern Report, at the upper end of the spectrum of damage costs for climate change, uses a very low discount rate, which is perhaps the most important reason why its damage value is so high. For this and other reasons the Stern Report figure, as high as it is, may actually be the most accurate, and certainly the most ethical, cost assessment for future climate damage.[49]

Irrespective of method, climate damage is by far the greatest air pollution cost of the aging natural gas power plants, with the upper estimate nearly as high as the cost of fuel. In 2005, the combined plants emitted over 8 million tons of greenhouse gases—down considerably from the 22.9 million tons they emitted in 1999. However, the remaining 8 million tons is sizable when compared to California's greenhouse gas reduction goals. In the Air Resources Board's AB32 plan, the new requirement to get 33 percent of electricity from renewable sources by 2020 is intended to avoid 21 million tons of greenhouse gas emissions.[50] Replacing the aging plants with renewable energy would be valuable as these aging plants emit significantly more greenhouse gases per kilowatt-hour than most other power plants in the state, and represent the next biggest savings in the electricity sector after eliminating coal.

Natural gas plants emit particulates, and the plants emit nearly 600 tons per year of this pollutant. Emission data are plant-wide rather than per unit, and there may be overlap between particulate and NOx emissions. Since they contribute to premature mortality, monetized damages are likely significant. Data on damage costs from particulates is not readily available, and so these are not included. In-state electric generation is reported to have been responsible for only 1.25% of total PM emissions in California. Similar to NOx, these levels pose limited regional threat on a year-round basis. However, the exposure will be much higher during the summer and in neighborhoods in proximity to a power plant.

Table 7: Pollution Damages

Pollutant	Emissions 2005 (tons)	Damages ($2005/ton)	Total damage ($2005 mil)
NOx	781	$1667–$6336	$1.3–$4.9
CO2	8,342,524	$12–$80	$100.1–$667.4
PM	585	N/A	N/A

8. Marine Ecosystem Costs of Aging Power Plants

Power plants that use once-through cooling use massive volumes of seawater to cool the plant, and discharge the heated water back into the ocean.[51] Large marine animals trapped in the intake flow are impinged against intake screens, while smaller animals passing through the screens are entrained in the water flowing through the plant. Both impingement and entrainment (I&E) lead to virtually 100 percent mortality. It's estimated that as many as 79 billion marine animals and larvae are killed each year in California due to once through cooling power plants.[52] If intake volumes are large enough, the stability of the entire ecosystem can be affected. The high temperature discharged water can also alter the surrounding environment.

Table 8: Marine Damages of Plants with I&E Studies

Plant	Maximum Flow (MGD)	APF estimate (acres) [53]	APF per MWh	APF per MGD (low)
Huntington Beach	516	2840 – 69752	0.0018 – 0.0449	5.5039
Morro Bay	668	230 – 759	0.0007 – 0.0024	0.3443
Moss Landing	1226	1135	0.0024	0.9258
Potrero	505	882	0.0023	1.7465

Economic loss can arise due to OTC impingement of commercial or recreational species of fish, as these fish have market values. The sea has value beyond fishing; however, were marine biodiversity to disappear, the consequences for Earth's ecosystems and humanity would be disastrous. The common measure of entrainment impacts on ecosystems is the Area of Production Foregone (APF). Several species are selected to represent the health of the ecosystem. For each species, the number of larvae entrained is compared to the density of the species in the surrounding water. From these data one can estimate the Proportional Mortality (PM), or ratio of larvae entrained versus total larvae at risk. The PM value estimates the percentage of the ecosystem that entrainment destroys. APF is calculated by multiplying the area of source water by the PM. For example, if the PM is 10 percent and the plant's intake affects 2,000 acres of ocean, then APF is 200 acres. So, effectively, 200 acres are being destroyed.

Determining APF requires extensive scientific studies. Few plants currently have reliable estimates of their APF. Those that do are summarized in Table 8. Column 4 shows the APF per MWh of 2005 generation for each plant, while column 5 calculates the lower estimate of APF per million gallons a day (MGD) that the plant is permitted to withdraw. Although this sample is small, the estimates of APF per MWh are quite similar. The APF per MGD, in contrast, varies quite a bit among the four plants. This greater variation is likely due to plants using less than their maximum permitted withdrawal. We will use the low estimate of APF/MWh, with an average over all four plants of 0.019 acres/MWh.

Costanza et al. estimate that the yearly value of estuaries is $12,172 per acre, while the yearly value of non-estuary coastal ecosystems is $2,161 per acre.[54] This includes commercial and recreational use, as well as biological services such as nutrient cycling that ecosystems provide. The authors stress that this is a low estimate. In the Moss Landing and Morro Bay studies, the cost of replacing habitat was estimated at $30,000/acre and $12,000–$25,000/acre, respectively.[55] Using the low value of 0.019 acres/MWh, these costs are $22.71/MWh for estuaries and $4.03/MWh for other coastal plants. The yearly damages would total $177.2 million for all plants. Using high APF/MWh estimates of 0.0449 acres/MWh for coastal and 0.024 acres/MWh for estuaries, based on Table 8, the damages are $540 million per year.

Table 9: Entrainment Cost of all OTC Plants

Plant	Entrainment Cost ($2005 mil) Low estimate	Entrainment Cost ($2005 mil) High estimate
Alamitos	30.3	38.3
Contra Costa	7.7	9.7
Encina	43.1	54.5
Haynes	31.7	40.1
Huntington Beach	6.4	150.8
Mandalay	8.1	10.2
Morro Bay	7.4	9.3
Moss Landing	10.8	13.6
Ormond Beach	2.1	50.0
Pittsburg	15.1	19.1
Potrero	8.9	11.3
Redondo Beach	1.8	41.7
Scattergood	3.8	90.9
Total	**177.2**	**539.5**

9. Summary of Aging Power Plant Costs

A summary of private and social costs of the power plant study group in 2005 is provided in the table included in this section.

Table 10 shows that the cost of operation for the study group power plants is between $1.89 billion and $3.66 billion per year, not counting profit. The rate needed to pay for this energy (excluding profit) ranges between 13.3 and 20.2 cents per kilowatt-hour. This is a high price to pay for 12,000 gigawatt hours annually from these plants, which supply about 4 percent of the state's electricity. There are two natural gas price scenarios, a low of $6.00 per million btu and a high of $10.00 per million btu for power plants in California. [56]

In fact, there is a range of energy cost rates from the different power plants that widely deviates from this average. The tables in Appendix 3 give estimates of these costs, using the assumptions in this report and data reported from existing plants, although profits are not included. The high and low values in Table 10 are most importantly determined by the price of fuel and carbon, which would be similar with all the plants. However, the operating cost and marine damages will vary greatly for each individual plant, and the ranges here should be considered as limits where the actual value for the combined plants may be closer to an average of these.

All these plants provide relatively high-priced power during the peak hours of the day or year, ranging between a low of 15 cents to a high of about 65 cents per kilowatt-hour. [57] This compares with average *retail rates* that customers pay of 14 cents per kilowatt-hour, of which about half—roughly 7 cents per kilowatt-hour—represents energy costs. The rest of the bill covers transmission and distribution, operation of the electric system, billing cost and utility profits, surcharges for special programs, and taxes. Some people may find

Table 10: Estimated Total Costs of all OTC Plants

	Low Cost	High Cost		Low Cost (per kwh)	High Cost per kwh)
Fuel Price/mmbtu	$6.00	$10.00			
Cost of Carbon/ton	$12	$80			
Costs to Owner					
Fixed Costs	$785,896,000	$785,896,000		$0.065	$0.065
O&M	$24,300,000	$316,500,000		$0.002	$0.026
Fuel	$808,900,872	$1,348,168,120		$0.067	$0.111
Total Costs to Owner	$1,619,096,872	$2,450,564,120		$0.133	$0.202
External Costs					
NOx	$1,301,094	$4,945,248		$0.0001	$0.0004
CO2	$100,000,000	$667,000,000		$0.008	$0.055
Marine Damages	$177,000,000	$540,000,000		$0.015	$0.044
Total External Costs	$278,301,094	$1,211,945,248		$0.023	$0.100
Total All Costs	**$1,897,397,966**	**$3,662,509,368**		**$0.156**	**$0.301**
Electric Generation	12,152,397,600	kwh			

the high cost of this energy baffling. But this only highlights how misleading it is to rely on "averages." The very high cost power only represents a small fraction of the state's electricity, and this is offset by other sources of power that are generally quite low in cost, such as hydroelectricity.

There is an additional "external" cost of between $278 million and $1.2 billion per year in environmental damages. This adds an average of 2.3 to 10.1 cents per kilowatt hour to the cost of electricity from the aging plants, not reflected in the customer's bill. *This suggests that internalizing the full cost of environmental damages could significantly alter decisions about what power resources are most cost effective*. Establishing such a pricing structure as a policy would help to make it worthwhile to encourage alternative ways of meeting the same energy needs, from sources that are less environmentally damaging. However, the effect will depend heavily on the methodology used to calculate the inputs, with the biggest variables being natural gas costs and whether the projected climate damages are calculated at a full-cost or discounted rate—as discussed earlier.

10. Scenario 1: Fossil Replacement

The seventeen aging natural gas power plants produce significant and quantifiable damages to the environment. To determine whether such impacts can be reduced in a cost-effective manner, this report establishes a base-case scenario, in which aging units are repowered at existing sites with newer, more efficient units, and closed-cycle cooling replaces once-through cooling (OTC) systems.

For such replacement to occur, it would have to be physically, politically and economically possible at each site, which may not be the case.[58] Additionally, we assume that when plants are repowered, they are left operating at the same capacity as previously. Such a plan may not be as profitable for power generator companies as repowering with bigger units, which decreases marginal capital and operating costs and increases overall generation. However, it is possible that companies would repower at the same capacity, particularly given the incentives of AB1576, which allows utility companies to pass on the costs of repowering to consumers.[59] Beyond that, there are serious risks as to whether there will be a market for additional power capacity, particularly as renewables come on line and displace natural gas generation.

In Scenario 1, each unit is repowered with a simple-cycle (SC) gas turbine. Combined-cycle turbines are more efficient than steam turbines or simple-cycle gas turbines, because the waste heat from the gas turbine is used to power one or more steam turbines. They are also cheaper per unit of electricity generated than simple-cycle turbines. However, the efficiency of combined cycle units decreases, and wear and tear increases, if they are run as peaking or load-following rather than baseload units. Consequently, for a load-following unit, the more cost-effective choice is usually a modern simple-cycle gas turbine.

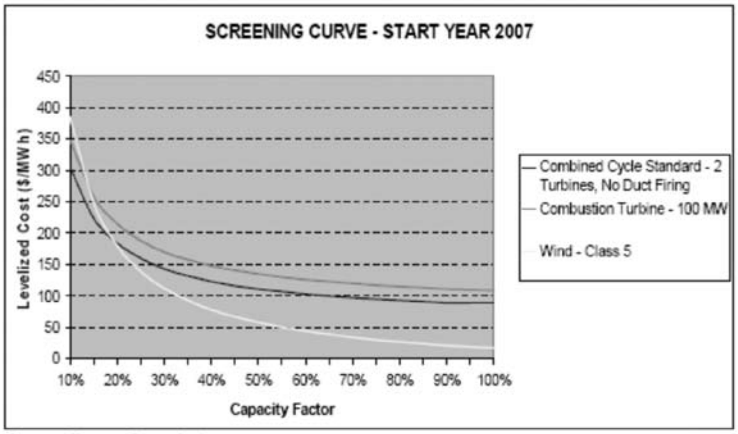
Private Costs

In estimating the costs to repower each plant, we use the California Energy Commission's (CEC's) 2007 "levelized costs" of Simple Cycle technology.[60] This is a standard method for calculating the cost of operating power plants. The levelized cost takes an inventory of all the expenses involved in building and operating a power plant over its full expected lifecycle, then divides this total expense by the amount of electricity generated over that time. The net result is a cost of energy expressed as a rate per kilowatt-hour or per megawatt-hour. The CEC's model is similar to our scenario, with a few exceptions. We propose to repower existing units instead of building on new sites, which will result in lower land and permitting costs. The model assumes a closed-cycle cooling system with access to recycled water, which will marginally increase capital and operating costs. The model also considers a range of capacity factors, rather than the 5 percent value used in the Energy Commission report.

A cost per megawatt-hour is assigned to each repowering project based on the plant's size, with larger plants generally benefitting from some economy of scale. Plant capacity is measured in two ways: nameplate and "capacity factor." The "nameplate capacity" is the full amount of power the plant is capable of producing, and is measured in megawatts. The "capacity factor" is the fraction of the full capacity that the plant actually operates at, averaged over time. The proposed replacement plant is assumed to operate at the same capacity factor as the existing plant. The CEC estimates a 60 percent capacity factor for new combined cycle turbines, whereas the plants in the study group ranged between 2 and 23 percent capacity factor in 2005 with an average of 9 percent.[61] This shows that the operational features of the aging plants are a better fit for simple cycle combustion turbines. Even with the efficiency losses imposed by closed-cycle cooling, the new units will be more efficient.

The chart below shows that the major contributory factor to the high cost of electricity from these power plants is the low operational capacity of the simple-cycle turbines. The CEC estimates simple cycle plants to be more than three times as expensive per unit of electricity, measured in kilowatt-hours or megawatt-hours, as combined cycle plants, even though the capital costs are comparatively close.[62] The 2003 CEC model showed levelized cost of $160 per megawatt-hour for simple cycle plants, which was revised to $600 per megawatt-hour in the 2007 report. This newer cost, while

Figure 10: Screening Curve in Terms of Dollars per Megawatt Hour



Source: Energy Commission

quite surprising, is based on an inventory of natural gas power plants in California. However, it is worth noting that the aging plants actually operated at 9 percent capacity factor, which is the same as the figure used in the 2003 CEC cost model.

Nevertheless, replacement plants operating at this capacity factor would generate electricity costing over $350 per MWh (i.e., over 35 cents per KWh). In order for power plants to have electricity costs under 20 cents per kilowatt-hour, they either require lower cost fuel than is assumed, or they would need to operate at a higher capacity factor than has been typical for the aging power plants. This fact will be significant later when other technology options are evaluated for comparison.

Fuel Savings

Although the total cost to plant owners of repowering is probably higher, fuel costs will usually decrease due to the lower heat rates of newer turbines. The model in this report projects the amount of fuel saved by repowering the plants with newer turbines, and assumes that natural gas costs $10 per million btu over the next 20 to 30 years. For comparison, recent prices of natural gas for power plants over the last few years (2005 to 2008) have generally fluctuated between $6 and $10 per million btu, although prices significantly higher and lower have occurred.

As the chart above shows, the general trend over the last decade has been increasing prices for natural gas for electric generators. This trend, however, is not new. While there was stability between 1982 and 1998, natural gas prices have escalated on average significantly more than the inflation rate since the 1950s. One important change since 1998 is increasing volatility of natural gas prices, which may double or fall by half over a period of months. This creates a risk for generators that rely on natural gas fuel, and an even greater risk to customers who must foot the bill.

Table 11 shows that the 19 plants (this includes 2 inland plants) used 134 trillion btu (about 130

Figure 11

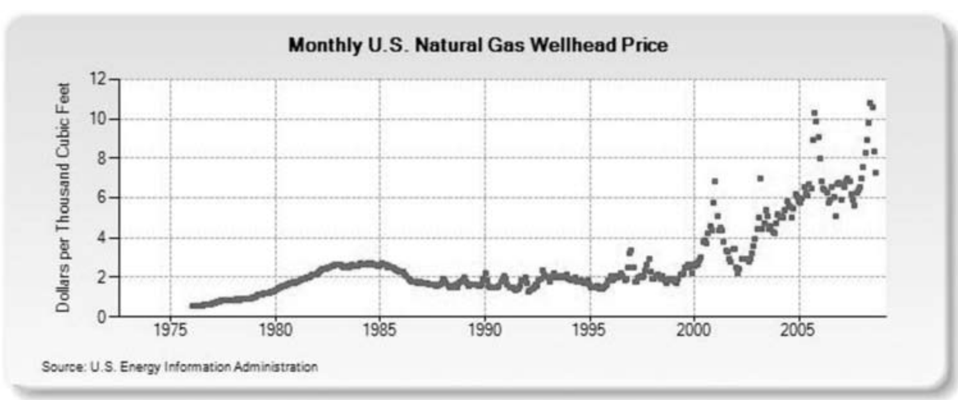


Table 11: Fuel Used by California's Aging Power Plants in 2005

Plant	Capacity Factor 2005	Capacity	Annual Generation	Aging Plant Heat Rate	Annual Fuel
	%	mw	mwh	btu/kwh	mmbtu
Alamitos	7.68	1,950	1,311,898	11,715	15,368,880
Broadway	12.26	66	70,882	11,981	849,242
Contra Costa	5.56	680	331,198	10,775	3,568,659
Coolwater	2.28	146	29,160	9,740	284,021
El Centro	15.99	118	165,285	9,994	1,651,863
El Segundo	11.32	670	664,393	11,054	7,344,205
Encina	22.91	929	1,864,425	11,688	21,791,399
Etiwanda	12.92	640	724,347	11,957	8,661,016
Haynes	13.9	1,126	1,371,063	10,008	13,721,595
Huntington Beach	19.98	888	1,554,220	10,896	16,934,784
Mandalay	9.26	430	348,806	10,466	3,650,600
Morro Bay	3.64	1,002	319,502	9,952	3,179,681
Moss Landing	3.61	1,478	467,397	9,916	4,634,707
Olive	3.62	101	32,028	14,745	472,257
Ormond Beach	3.92	1,500	515,088	11,190	5,763,835
Pittsburg	5.44	1,370	652,865	11,192	7,306,868
Potrero	21.27	207	385,693	10,787	4,160,472
Redondo Beach	3.74	1,310	429,187	11,692	5,018,060
Scattergood	13.32	803	936,966	11,158	10,454,668
Total	**9.0%**	**15,414**	**12,174,404**		**134,816,812**

billion cubic feet) of natural gas in 2005 to generate 12 million megawatt-hours. At $6 per million btu, the total fuel cost would be $780 million. The plants generated far more electricity in 2002, putting out over 35 million megawatt-hours and consuming 350 billion cubic feet of natural gas. Thus, there has been considerable variation in electric generation and fuel use from year to year.

At a projected $10 per million btu average price for natural gas over the 20 year economic life of a new power plant, the annual cost for natural gas would be $1.348 billion per year for the aging plants. A new plant would probably have a lower heat rate, with the best being about 9,200 btu per kilowatt-hour. The savings in fuel would be 18.5 percent, or nearly $250 million per year at 2005 generation rates compared to the older plants, assuming the new plants operate at the same level of electric generation as the aging plants.

However, the common assumption that the new plants would use less natural gas is probably unrealistic. The lower heat rate (higher efficiency) would make the new plants more competitive for more hours of the year; thus electricity generation would very likely be significantly higher than in the aging plants. This would tend to erase the fuel efficiency and carbon benefits of the new plants. A formal metric of competitiveness is called the "market heat rate," and was illustrated by the California Energy Commission's report on the aging plants. The following table shows the changing limit of competitive heat rates for power plants over the course of the years.

The "Gas" column shows the average daily price for natural gas over the course of each month, while the electricity column reflects the cost of electricity on the wholesale market during peak hours of the day. The MHR, or Market Heat Rate, shows the maximum number of British Thermal Units of heat energy from natural gas fuel that a generator can use to produce one kilowatt-hour of electricity and still not lose money, given how much the fuel costs and how much they can sell electricity for on the market. [63]

The market heat rate does not recover the fixed costs, but only the variable ones. These include fuel

Table 12: Monthly Market Efficiency of Natural Gas Power Plants

Average Market Heat Rates, SP15

2004			
Month	Gas	Elect	MHR/1,000
Jan	5.23	56.99	10.72
Feb	5.36	54.06	9.80
Mar	5.10	52.16	9.94
Apr	4.68	50.18	10.35
May	4.62	50.93	10.43
Jun	4.69	56.64	11.45
Jul	4.80	64.90	12.78
Aug	4.85	69.83	13.56
Sep	4.84	61.83	12.05
Oct	4.84	54.75	10.43
Nov	5.01	56.26	10.34
Dec	5.18	58.82	10.47

Source: Forward market data from November 2002 – June 2004

plus operation and maintenance during the hours of peak demand. From October through May the market heat rate reaches a peak of 10,720 in January, but most of the rest of the time it is well below this. That means that any power plant with a higher heat rate will not recover the cost of fuel plus operations. Only six of the 19 plants, representing only 4,300 out of the 15,400 megawatts of total capacity, have heat rates low enough even to meet this minimum level of cost recovery in January.

In fact, even the plants with the lowest heat rates will not generally be able to operate between October and May as they have significant additional costs beyond the variable ones. The rest of the plants with the higher heat rates will only be competitive during the four summer months of June to September, when market heat rates usually soar above 12,000 btu per kilowatt-hour. This is only during the peak demand hours. During summer nights the plants once again become uneconomic. However, they must be kept idling at minimum power all night long in order to be ready to generate power in the morning, and cannot be shut completely off. This consumes a considerable amount of additional fuel that produces no salable electricity. The extra fuel cost must be recovered, and this requires a significantly higher market heat rate than the specified heat rate of the plant would suggest.

The California Energy Commission report projects an effective heat rate of about 10,000 btu per kilowatt-hour for a new natural gas combustion turbine, and this would allow a new plant to sell power nearly year round in a competitive manner, at least during the daytime. In some cases, developers have even proposed building baseload plants to replace aging plants, even when there is no market need for such a service. This would mean replacing aging plants that only produce at nine percent of annual capacity with baseload plants that might operate at 60 percent capacity or more. Even though such plants would be much more efficient, there would be absolutely no fuel, cost or emission savings due to the much increased operation of the plant.

Pollution Reduction

New turbines have lower emission rates than older steam units, even those with Selective Catalytic Reduction pollution technology. Table 13 summarizes emission rates of pollutants, with damages quantified for five types of replacement plants.

Replacing aging plants with new simple cycle (SC) plants would reduce the nitrogen oxide emission

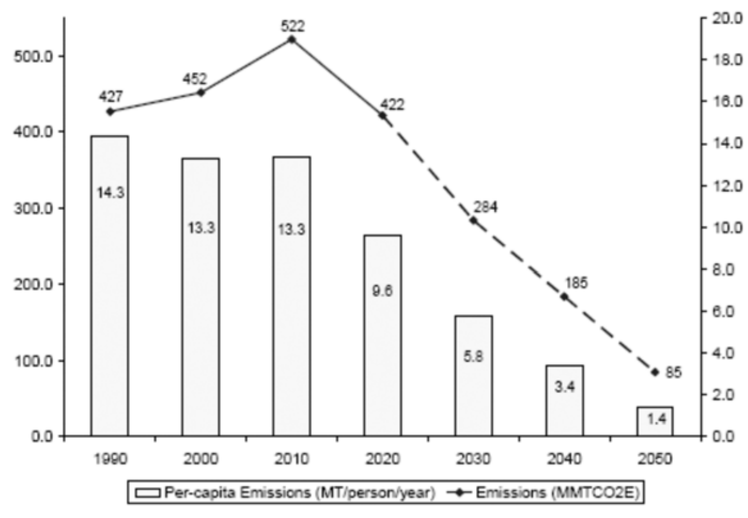
Table 13: Emission Rates of New Natural Gas Plants

Turbine Type	NOx emissions rate (lbs/MWh)	CO2 (lbs/MWh)
Conventional Combined Cycle	0.056	817.62
Advanced Combined Cycle	0.046	761.47
Simple & Conventional Simple Cycle	0.093	1083.84
Advanced Simple Cycle	0.076	886.63
Average, Old Plants	0.128	1370.47

Table 14: Carbon Dioxide Cost of all Aging Plants

Plant	Annual CO2 Old	CO2 New	Savings	CO2 Savings Value
	Tons	Tons	Tons	
Alamitos	899,080	706,063	193,016	$4,825,405
Broadway	49,681	38,149	11,532	$288,294
Contra Costa	208,767	178,251	30,516	$762,894
Coolwater	16,615	15,694	921	$23,029
El Centro	96,634	88,957	7,677	$191,934
El Segundo	429,636	357,577	72,059	$1,801,486
Encina	1,274,797	1,003,434	271,363	$6,784,083
Etiwanda	506,669	389,843	116,826	$2,920,648
Haynes	703,016	737,906	(34,890)	($872,253)
Huntington Beach	990,685	836,481	154,204	$3,855,088
Mandalay	213,560	187,727	25,833	$645,822
Morro Bay	186,011	171,956	14,056	$351,388
Moss Landing	271,130	251,553	19,577	$489,435
Olive	27,627	17,238	10,389	$259,736
Ormond Beach	337,184	277,220	59,964	$1,499,099
Pittsburg	427,452	351,372	76,080	$1,901,992
Potrero	243,388	207,580	35,808	$895,189
Redondo Beach	293,556	230,989	62,568	$1,564,195
Scattergood	611,598	504,275	107,323	$2,683,073
Total	7,787,086	6,552,264	1,234,822	$30,870,538
CO2 energy rate	117	lbs per mmbtu		
CO2 value	$25	per ton		

Figure 12: California Greenhouse Gas Emissions Trajectory Toward 2050



Source: California Air Resources Board [67]

rate by 27 percent, from 0.128 to 0.093 pounds per megawatt-hour.[64] Multiplying the emission rate for each repowered plant by its expected annual generation gives approximate yearly emissions for each plant. The largest environmental benefit is from CO2 reduction, with relatively little economic value assigned for NOx reduction. While NOx is left out of account here, savings could be up to $1.33 million per year for all the plants combined. However, as stated above, the reduction in emission rates does not necessarily mean that absolute levels of pollutants would be lowered. That is due to the effect of the market heat rate, which will tend to increase the number of hours per year that new plants would operate. For this reason it is entirely possible that new plants would consume more fuel and emit more pollutants than the aging plants.[65]

Annual CO2 savings, assuming a cost of carbon dioxide at $25 per ton, would be over $30 million per year, or approximately $600 million over the economic lifecycle of the plants. On the other hand, total carbon costs would still accrue at $163.8 million per year, which means between $4.9 and $8.2 billion in carbon costs over the 30 to 50 year lifecycle of the replacement plants. The actual climate damage depends on the carbon damage rate, which for this report is assumed to range from $12 to $80 per ton. Thus carbon savings achieved through a replacement of aging power plants with newer, more efficient plants would amount to 18 percent. This would meet the 15% reduction target for 2020 required under AB 32, the Global Warming Solutions Act of 2006.[66] However, the plants would continue to operate for another 20 to 40 years, during which time the state—under the Governor's Executive Order S-3-05—plans to reduce greenhouse gas emissions by 80 percent below 1990 levels. The replacement plants would fall far short of making the necessary contribution to reducing greenhouse gas levels required over this longer timeframe.

Avoided Marine Damages

Equipped with closed-cycle or dry cooling, new simple-cycle turbines are assumed to eliminate their use of seawater completely. Even if some plants must continue to use seawater, the volume required for closed-cycle cooling is less than 5 percent of OTC cooling needs. Closed-cycle cooling has some minor disadvantages compared to OTC: the increased energy required to operate it, the extra cost to install it, cooling towers emit plumes of vapor that might be considered unsightly (which can be abated at a cost of $6/kW), and any pollutants in the source water will be discharged in higher concentrations.[68] Because the damages of these concentrated contaminants have not been extensively studied, they are not accounted for here. For all practical purposes, and especially when compared to the aging plants, the new gas turbines will inflict no significant marine damage.

Both the repowering and clean energy replacement options would eliminate the marine damage problem. Of the 12,174,404 MWh total generated by the aging power plants in 2005, 86 percent of the electricity, or 10,469,987 megawatt-hours, was produced by OTC plants. The environmental cost of OTC for marine damages ranges between $177 million and $540 million per year for existing power plants that would be avoided in the replacement scenarios.

Summary of Cost for Scenario 1

Replacing aging plants with new natural gas power plants will avoid marine damages from the existing plants. It may also reduce fuel consumption and greenhouse gas emissions by about 18 percent; however this assumes that the new plant operates at a similar capacity as the aging plants—which is unlikely. These are the primary benefits of a replacement option. Air pollution is likely to be relatively unchanged, since the aging power plants have generally been retrofitted to comply with modern air quality requirements. The new power plants may also have lower operation and maintenance expenses due to reduced repair needs. However, this last point is not certain, as many newer turbines have been found to have more problems than originally expected. [69]

On the other side of the coin, new power plants would require a large infusion of new capital spending. These new plants would be much more expensive than the older ones they would replace, at a projected total of $15.4 billion for all the plants combined. This borrowed and invested money must return a rate of interest and profit. Assuming an 11 percent average weighted cost of capital over a 20 year period would mean that the $15.4 billion investment (equivalent to $770 million per year) would need to return over $49 billion in combined interest and profit. Fuel would add another $1.3 billion per year, or $26 billion over 20 years. Combined lifecycle costs would approach $100 billion, not including environmental damages. Natural gas fuel prices are also expected to be higher in the future than they have in the past. The CEC natural gas price prediction for a plant starting operation in 2010 averages about $10 per MMbtu, with prices gradually rising over a 20 year period up to 2029.

The annual combined cost to the owners of all the plants is estimated to range between $3.68 and $4.22 billion to generate 12.1 billion kilowatt-hours. This translates into a wholesale energy rate of 30.3 to 34.8 cents per kilowatt-hour. The figure predicted by the Energy Commission chart shown previously is slightly higher, at just over 35 cents per kilowatt-hour.[70] This is partly because the CEC model adds in the cost of taxes. In addition, their model also takes into account the fact that power plants operating at less than full capacity will operate at less than their rated efficiency.

The environmental damages range between 0.6 cents per kilowatt-hour to as high as 4.4 cents per kilowatt-hour. While this is significantly lower than the existing plants' environmental cost at 2.3 to 10.1 cents per kilowatt-hour, achieving this reduced environmental damage results in a much higher cost of electricity. Thus, building newer plants could be interpreted as internalizing the environmental costs of the aging OTC plants, especially since the environmental damage is a major factor for considering replacement in the first place. However, the new plants would also incur continuing external costs, particularly for carbon.

All these figures assume that the replacement plant operates in a similar manner to the current plant. However, this may not be true since power plants have a strong motive to try to sell more electricity. If this is the case, then operation and maintenance (O&M) and fuel costs will increase and environmental damage may be much greater. These could rise to where the replacement plants would have more carbon and other air emissions than the current plants that they would replace. This is an important risk if new natural gas plants are built.

Table 15: Summary of Annual Costs, Baseline Scenario

	Low	High		Low cost per kwh	High cost per kwh
Fuel Price/mmbtu	$6.00	$10.00			
Cost of Carbon/ton	$12	$80			
Costs to Owner					
Capital Cost	$770,700,000	$770,000,000		$0.063	$0.063
Interest & Profit	$1,695,540,000	$1,695,540,000		$0.140	$0.140
O&M	$411,707,000	$411,707,000		$0.034	$0.034
Fuel	$808,900,872	$1,348,168,120		$0.067	$0.111
Total Costs to Owner	$3,686,847,872	$4,225,415,120		$0.303	$0.348
External Costs					
NOx	$1,301,094	$4,945,248		$0.0001	$0.0004
CO2	$71,000,000	$524,000,000		$0.006	$0.043
Total External Costs	$72,301,094	$528,945,248		$0.006	$0.044
Total All Costs	$3,759,148,966	$4,754,360,368		$0.309	$0.391
Electric Generation	12,152,397,600	kwh			

11. Scenario 2 – Green Energy Replacement

Although new natural gas plants are preferable to the current aging plants from an environmental standpoint, pollution from the new plants would cause hundreds of millions of dollars in damages every year. The majority of this cost comes from greenhouse gas emissions, which California must curb if it is to reach the climate protection goals of AB32.

Scenario 2 proposes a replacement for the aging power plants by applying California's clean energy policies. These include accomplishing greater energy efficiency improvements, increasing renewable energy, and implementing programs for reducing peak demand. The resources chosen for this model all address peak demand to replace the electric generation profile of the aging plants.

Certain functions of the aging plants—such as voltage regulation and the ability to modify generation over the course of the day—might have to be met with other technologies. However, such resources are not entirely lacking in California. As pointed out earlier in the report, there are currently 41,499 megawatts of natural gas power plants in California. If all of the 15,400 megawatts of aging plants were retired by 2012, as the Energy Commission would like, the state will still continue to operate 26,000 megawatts of existing natural gas plants.

In addition, nearly 2,000 more megawatts of natural gas plants are currently under construction and due to come on-line by the end of 2010. Another 18,000 megawatts of power can be imported over existing transmission wires, and more transmission capacity is likely to be built in the future. There is also some capacity to vary the electric generation from hydroelectric plants, especially the 4,100 megawatts of pumped storage that is specifically designed to meet peak demand.[71]

One important function of the aging plants is to meet local reliability needs. Retiring these plants will require replacing this capacity as well. Local resources, such as solar built on rooftops or at substations, and energy efficiency measures, can help. And there are thousands of megawatts of natural gas peaking capacity that is already in place that can also meet local needs.

Another issue is the increasing demand for electricity. The Energy Commission's first study on aging plants reviewed the ability to meet demand growth with demand side programs in place at the time the report was written in 2004. The projected increase in peak demand from 2004 to 2008 was 3,194 megawatts. During that time new energy efficiency improvements were supposed to meet 1,100 megawatts of that growth, while peak demand reduction programs were to meet another 1,549 megawatts. The two combined left 545 megawatts of demand growth that would have to be met with new plants over a four year period, a rate of only 136 megawatts per year.[72]

Since 2004, spending for energy efficiency has more than doubled to nearly $1 billion per year,[73] and the bar for performance in these programs has been raised significantly. In addition, the California Solar Initiative has committed $3 billion in funding to put photovoltaic systems on rooftops throughout the state. The target is to install an average of 300 megawatts per year over the 10 year life of the program. In order to reduce demand growth, the state does not even have to meet all of these targets.

The California Ocean Protection Council and the State Water Resources Control Board (SWRCB) commissioned a study by ICF Jones & Stokes to examine the effects on electric system reliability of various scenarios relating to regulation of power plants using once-through cooling.[74] This included computer modeling of the operation of these power plants on the electric grid. While acknowledging the limitations of their efforts, they were able to draw certain general conclusions. The report had an alternate scenario which examined just the option of retiring the natural gas plants, and concluded that the cost and resources necessary to assure grid reliability depended heavily on the timing of retirement.

If retirement is delayed only 3 years beyond the Energy Commission's preferred 2012 date, then no new electricity generation would be needed, and only some relatively minor transmission upgrades. This represented the low range of cost, as the SWRCB states, "as little as $135 million in modest, low-impact transmission upgrades in the still unlikely event that all but the nuclear plants are retired in 2015."[75] As retirement of the 4,472 megawatts of in-state nuclear is not likely until the mid-2020s due to long term contracts, this is a viable scenario.

With this in mind, and with the goal of reducing other natural gas generation in the state, the following resources should be able to allow retirement of all the aging natural gas power plants, allow for population growth, and dramatically reduce other fossil fuel energy.

a. Photovoltaics.

The energy of the sun is absorbed by flat panels containing semiconductor cells that directly convert light into electricity. These systems can be located on-site wherever power is needed. Fixed solar panels provide energy during the peak hours of demand, and electricity production rises and falls during the day, closely following the bell-shaped summer demand curve. Photovoltaics can reduce the need for transmission upgrades, and the delays inherent in building large power facilities. 3,000 megawatts of new photovoltaic capacity is planned in California by 2017 under the California Solar Initiative, with $3 billion dollars in rebates committed toward this goal. California's Renewable Energy Transmission Initiative (RETI) has projected that 4,200 megawatts may be installed by 2020, the date when the 33 percent renewable target is intended to be met.[76] Rooftop solar has a wide range of possible cost, depending especially on the orientation of the roof, and clear access to sunshine. Also important is the rate of return expected on the investment.

In July 2009, the California Energy Commission denied an application for a 100-megawatt natural gas power plant to be located in Chula Vista in part because rooftop solar PV could potentially provide the same power for similar costs. In particular, the CEC ruled that locally installed solar PV arrays on rooftops and over parking lots can provide the same peak time electricity that the power plant was intended to provide—on hot, sunny days. This landmark decision is one of the few where a permitting agency ruled that solar power is a viable and cost effective alternative to fossil fuels. This decision is indicative of the fast-sinking cost of solar PV.[77]

In Gainesville, Florida the local utility has offered to pay residential customers 33 cents per kilowatt-hour for all electricity generated from their photovoltaic systems using a mechanism called a "Feed In Tariff." This is calculated to return a 5 percent annual profit over a 20 year contract period, and assumes the customer takes advantage of a 30 percent federal tax credit against the full purchase price of the system. Commercial customers can attain lower cost solar electricity through better deals on system prices as well as generally better performance when these are located on unshaded commercial rooftops. California does not have a Feed in Tariff program, but legislation is pending which would introduce it.

According to utility planning documents, photovoltaics on customer rooftops count as equivalent to about 40 to 50 percent of the capacity value of a natural gas power plant. However, this ignores the fact that simple cycle natural gas plants that provide peak power lose efficiency during the heat of summer, which reduces output by 25 percent or more. The real load carrying capacity of 4,200 megawatts of photovoltaics would be near 2,100 megawatts.

One-axis tracking photovoltaic panels at the SunEdison photovoltaic power plant near Alamosa, Colorado. Source: NREL.

The real load carrying capacity of natural gas plants should also be reduced—to 3,000 megawatts or less. In addition, an onsite solar system avoids the energy losses inherent in the transmission and distribution system, which can be 10 percent or higher on hot summer days. The difference between the performance of a natural gas plant and a photovoltaic system is thus likely to be not dissimilar.

Projections of the cost of solar PV are constantly changing, and most recently have been declining rapidly. In 2007, the California Energy Commission calculated the cost of electricity from photovoltaics to be 72 cents per kilowatt-hour.[78] In 2009, California's Renewable Energy Transmission Initiative (RETI) projected a range of 22 to 30 cents per kilowatt-hour, which is in line with our model projection for utility scale projects. These would be the same type of projects that RETI proposes: systems up to 20 megawatts that might be installed at or near existing substations in urban or suburban areas with suitable solar resource and a sufficient quantity of available flat ground. The major benefit of such sites is that they would require little to no upgrades in existing transmission systems, and could potentially add to local as well as to statewide reliability. Other projections indicate that the cost of thin-film solar promises to dramatically change the equation. According to some industry projections, thin film solar may soon cost as low as 11.4 cents per kilowatt hour, well below even our most optimistic forecast.[79]

In RETI's model, photovoltaic panels would be mounted on tracking systems, which increase power generation significantly. Rather than 15 to 20 percent capacity factor typical of rooftop systems, these tracking panels produce at 19 to 27 percent capacity factor. However, we find that a similar cost of energy could be obtained with fixed (non-tracking) systems that would produce significantly less electricity. This lower production would be offset by lower installed cost largely because it would not require tracking equipment.

Larger photovoltaic systems can help to offset the cost of smaller rooftop systems and control overall program costs. For example, one 20 megawatt system is equivalent to 6,000 to 10,000 typical household rooftop systems and therefore can easily balance the higher unit cost of many smaller systems.

b. Solar Thermal Power.

Solar thermal generators use mirrors to focus the heat of the sun onto long tubes that carry a heat transfer fluid. The fluid boils water to steam which powers a turbine and generates electricity. Nearly 360 megawatts of solar thermal plants have operated for 20 years or more in the California desert, providing reliable power to the grid.

Steam turbines powered by solar thermal technology provide energy during the day.[80] If this system is supplemented with storage or backup fuel supply, then reliability can virtually match that of a natural gas power plant. Because peak electricity demand generally occurs when solar thermal output is also available, and because much of California has abundant and reliable sunshine, solar could provide a significant portion of peak power needs. Approximately 3,000 megawatts of California's load curve could be appropriately met by solar thermal plants with no or minimal power storage. These plants begin production in the early morning shortly after sunrise and maintain a relatively flat level of electric generation through the rest of the day.

Solar thermal plants are best sited in regions with excellent sun, which is why desert regions have typically been preferred. However, when the value of being close to load demand—and the possibility of avoiding transmission congestion in the summer—is taken into account, areas with less sun can also be valuable for solar thermal development. According to the California Energy Commission, the cost of electricity from solar thermal power plants is about 28 cents per kilowatt-hour for a merchant power plant, and below 20 cents per kilowatt-hour for a publicly owned and financed facility.[81] A RETI report, however, finds significantly lower costs for this technology, mostly in the range of 15 to 16 cents per kilowatt-hour. [82] The results of our cost modeling lie in the middle

of these two reports. We find a range of 17 to 23 cents per kilowatt-hour under the RETI assumptions of capital cost between $4,800 and $5,200 per kilowatt, and performance between 24 and 31 percent capacity factors.

This last figure compares favorably with the electricity from new simple cycle natural gas power plants that provide for peak energy needs in nearly any feasible range in which such a plant might normally operate, as the screening curve in the earlier section showed. Only if such a new natural gas plant were to operate at annual capacity factors well over 35 percent would the cost of electricity be lower than the solar thermal cost RETI reports. At capacity factors from 10 to 22 percent, the screening curve showed cost of energy for a new plant of 20 to 35 cents per kilowatt-hour or higher.

Solar thermal plants generally are not considered to carry 100 percent reliability, and their Effective Load Carrying Capacity (ELCC) is adjusted to account for this. As mentioned earlier, a solar thermal plant might be rated at about 60 percent of its capacity. However, adding storage or providing natural gas or renewable biogas as a backup fuel for the solar facility can increase the ELCC to as high as 100 percent. This will increase the cost of the power plant somewhat. However, the added benefits of providing reliable power for a wider range of hours will also add the ability to sell more power and make the plant more useful for a variety of purposes. For example, the plant will be able to sell capacity contracts for the full capacity of the plant. This will also save money for the grid as a whole, and thus for customers, by avoiding the need to build additional backup capacity.

Several utility companies have committed to buying power from Concentrating Solar Power (CSP) installations with large megawatt capacities by 2014. The CSP industry estimates it could produce up to 600 megawatts of parabolic trough capacity in 2010 and 1,200 megawatts in 2014 if there are favorable market conditions. The total capacity is projected to be 5,000 megawatts, which could be achieved between 2015 and 2020.

c. Energy Storage Technologies.

Energy storage technologies are ideal for reducing the need to build power plants to meet peak demand. Many of the approaches, including compressed air and pumped hydro have been utilized for decades. PG&E has announced plans for a $300 million compressed air project in Kern County. Batteries, ultracapacitors, and superconducting magnetic energy storage also hold great promise for shaping energy supplies to meet peak demand.

d. Peak Demand Reduction.

Reducing peak demand with voluntary curtailments under conditions of stress in the electric system is a valuable and local resource. Like photovoltaics, it does not require transmission, and the infrastructure blends into existing buildings with minimal footprint. There are different types of demand reduction programs. In one type of program, called "demand response," utility companies sign contracts with large power users such as industrial manufacturing plants to reduce or cut out their power consumption during power emergencies. In exchange for this concession, the manufacturer will be paid an agreed upon price for avoided energy purchases. An added benefit to the customer is avoiding rolling blackouts.

Further opportunities to reduce peak energy demand should be explored, including real-time pricing, expanding interruptible power programs to the commercial and residential sectors, and measures to reduce waste of electricity during power emergencies, such as requiring businesses to shut the doors of air-conditioned commercial establishments and keeping thermostats above a specified level.

Investor-owned utility companies are required by state regulators to get 5 percent of their power capacity needs, equivalent to at least 2,000 megawatts, from demand response programs.[83] In 2002, the California Energy Commission projected cost curves for market based demand response resources and found them to be equivalent to operation of combustion peakers.[84]

The actual cost, which the chart shows can range between $1.00 and $8.50 per kilowatt-hour, is very high due to the very few hours per year that the resource is called upon. Nevertheless, building and operating a peak natural gas plant to provide a similar service is shown to have a similar cost per kilowatt-hour for each assumed number of hours per year that the resource needs to be called upon. It should be noted that the cost of building new peaker plants has doubled since the Energy Commission created the above model, and that natural gas prices have also doubled. At this point, demand response programs should be decisively cheaper than building a new natural gas plant to serve the same purpose.

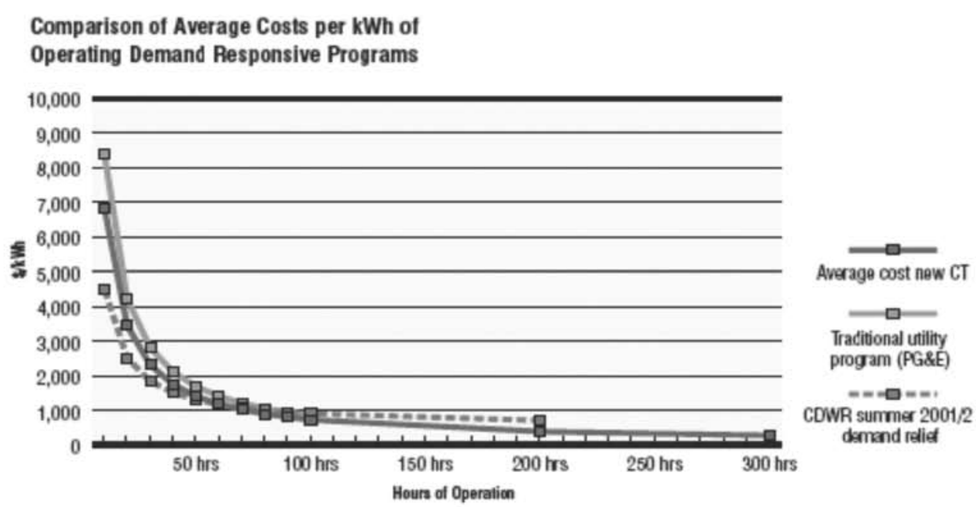
The Energy Commission has also indicated that demand reduction programs may actually meet the needs of grid reliability in a better manner than building new natural gas power plants from a technical as well as a policy standpoint:

> "…sole reliance upon generation to provide peaking resource needs violates our flexibility criteria. Committing too much of resource additions to peakers is imprudent, given the potential that load curtailment programs and real-time price (RTP) rates appear to offer." [85]

e. Energy Efficiency.

While California has aggressive energy efficiency programs, there has been only limited targeting of the primary driver of peak demand: air conditioning. Ground-source heat pumps, better home insulation, light colored roofing, and shade trees could go far toward reducing summer demand. A study from the US Forest Service, for example, showed that planting shade trees has the potential to avoid the need for over 700 megawatts of power plants in California.[86] Geothermal heat pumps use the natural and relatively constant ground temperature

Figure 13



of about 55 degrees F. to cool a fluid in pipes that in turn cools your house.

These resources, as well as many other efficiency measures, can be cost effective if programs are well run. As mentioned above, California is investing $1 billion per year in energy efficiency improvements, and state regulators are planning for over 4,500 megawatts of capacity savings by 2020 relative to baseline growth assumptions, including the new Big Bold Energy Efficiency Strategies (BBEES).

Estimating the cost of energy efficiency savings is somewhat an art, as a number of variables are difficult to determine. The most important factor is how long an investment in an efficiency measure will continue to generate savings. This variable is called "Estimated Useful Life," and can range from two to over ten years, depending on the specific measure. CPUC staff has estimated that the average cost of energy efficiency under the state's programs is between four and six cents per kilowatt-hour.[87] To be conservative we assume the higher cost in the range here. In any case this is significantly less than the average cost of generating electricity in California, and a small fraction of the cost of peak electric power that is supplied by the aging plants.

Table 16

Estimates of 2016 Energy Savings from Big Bold Energy Efficiency Strategies

	Estimate of Sector or Segment Consumption Magnitude			Estimated EE Potential		
	TWH	MW	Million Therms	TWH	MW	Million Therms
New Commercial	9	1,900	50	4.5	950	25
New Residential	6	2,900	500	1	500	100–200
HVAC	19	14,400	3,000	2	1,400	300
Industrial	40	7,400	2,900	5	650	500

Table 17

Aging Power Plants: Proposed Replacement Portfolio (High Cost Scenario)

	MW	ELCC	MW-ELCC	Capacity Factor	Hour-equiv./Yr	MWh	Cost/ KWh	Annual Cost
Energy Efficiency (BBEES)	3,500	100%	3,500	50%	4,380	15,330,000	$0.060	$919,800,000
New DR	1,200	100%	1,200	0.1%	9	10,512	$8.500	$89,352,000
Substation PV	6,000	60%	3,600	23%	2,017	12,099,878	$0.297	$3,599,128,765
DG Photovoltaics	4,200	50%	2,100	16%	1,430	6,005,125	$0.383	$2,299,219,927
Solar Thermal	5,500	60%	3,300	22%	1,942	10,679,394	$0.227	$2,424,673,614
Generation Only	15,700		9,000			28,784,397	$0.289	$8,323,022,306
Total with Efficiency	20,400		13,700			44,124,909	$0.211	$9,332,174,306

The Combined Cost for Scenario 2

In our model portfolio we assume a mix of substation photovoltaic power generation with 4,200 megawatts of customer-owned photovoltaics primarily on residential and commercial rooftops. The cost of electricity from customer owned generation would typically cost more than the larger substation solar plants; however, most of this cost is currently assumed by the customers themselves on a voluntary basis. Only a few relatively minor costs affect electric rates, such as the state rebates that are supported by a very small surcharge on everyone's utility bills. The tables that show cost, however, reflect a full cost of electricity from all sources. It is important to note that the actual rate impact is likely to be less than this average "levelized" cost.

Two green energy scenarios are presented in this report, one—the "high cost scenario"—that reflects a) recent historical costs of solar photovoltaics, b) relatively low performance, and c) a 20 year economic life; and the "low cost scenario" that projects d) the lower price of solar systems that might be expected over the next decade as technological performance improves and manufacturing costs fall, e) improved performance, and f) a 30 year economic life.

In the "high cost scenario" (Table 17) rooftop photovoltaics is projected to average about 38 cents per kilowatt-hour, with a range of 35 to 50 cents per kilowatt-hour for residential and commercial scale systems, while larger solar projects would produce electricity at about 30 cents per kilowatt hour (the high side of the RETI report range).

In the "low cost scenario" (Table 18) rooftop solar electricity ranges from 29 to 34 cents per kilowatt-hour, and the larger systems cost 18 cents per kilowatt-hour.

Table 18

Aging Power Plants: Proposed Replacement Portfolio (Low Cost Scenario)

	MW	ELCC	MW-ELCC	Capacity Factor	Hour-Equiv/Year	MWh	Cost/ KWh	Annual Cost
Energy Efficiency (BBEES)	3,500	100%	3,500	50%	4,380	15,330,000	$0.060	$919,800,000
New DR	1,200	100%	1,200	0.1%	9	10,512	$8.500	$89,352,000
Substation PV	6,000	60%	3,600	22%	1,970	11,818,911	$0.181	$2,135,626,614
DG Photovoltaics	4,200	50%	2,100	17%	1,506	6,325,306	$0.301	$1,901,009,432
Solar Thermal	5,500	60%	3,300	22%	1,942	10,679,394	$0.227	$2,424,673,614
Generation Only	15,700		9,000			28,823,611	$0.224	$6,461,309,660
Total w/Efficiency	20,400		13,700			44,164,123	$0.169	$7,470,461,660

Total Private Cost of Scenario 2

Assembling a portfolio of options for replacing the aging plants and avoiding new ones would make the most sense. Because a green energy system includes demand reduction it does not require as much power plant infrastructure. In general, the energy efficiency and peak demand reduction programs are, by definition, cost effective resources. In other words, the energy they save is worth more than the cost of the measures. Thus, they do not have a net cost. At worst they are zero net cost or—more typically—a net savings. Utility programs for energy efficiency have been measured and found to have a benefit to cost ratio that is better than one overall, thus verifying the assumption of zero net cost. Also, there is significant potential to improve the performance of the state's efficiency programs. As discussed earlier, California has allocated a regular budget of about $1 billion annually to achieve energy efficiency goals. The CPUC has established that funding for utility efficiency programs will rise to $1.6 billion annually by 2012."

The combined efficiency and demand reduction program targets are 4,500 and 2,000 megawatts respectively, for a combined savings of 6,500 megawatts. We will assume a program shortfall of 25 percent, resulting in a savings of 4,875 megawatts. Because this program is on the demand side it avoids transmission and distribution system losses, which can be 10 percent or higher on hot summer days when the current aging plants are most called upon. Thus the 4,875 megawatts of savings is worth about 5,300 megawatts.

This portfolio is approximately equivalent to the load carrying capacity of the aging plants. However, if the state actually enforces the requirement to build 33 percent renewables by 2020, there would be a larger reduction in need for replacement plants beyond what is proposed here. The efficiency component effectively lowers the average cost per kilowatt-hour from 21 to 17 cents.

12. Conclusion: Comparison of Two Scenarios

Replacing the current aging plants with new natural gas plants is projected to greatly increase the cost of power for the same amount of capacity, 15,400 megawatts, and electric generation of 12 million megawatt-hours per year reflecting an average capacity factor of about 9 percent. While the aging plants appear to have low cost at an estimated range of 13.3 and 20.2 cents per kilowatt-hour, this excludes the "external cost" which represents their damage to the environment—particularly in the form of rampant and continuous destruction of marine life and global climate change. If the external cost is included, then the range rises to between 15.6 and 30.2 cents per kilowatt-hour in the high and low cost alternatives.

The low cost alternatives for both the aging plant status quo and Fossil Replacement scenario assume: low cost of carbon at $12 per ton, low cost for natural gas at $6 per million btu, and the lowest value for damage to marine life. The high cost assumptions are: $10 per million btu for natural gas, $80 per ton for climate damage, and the highest estimated value of marine life. Note that the price of natural gas is the full delivered cost for power plants in California, which is approximately one dollar per million btu higher than the market prices at Henry Hub or NYMEX. Consideration of price in the model also needs to take into account the future likely cost of natural gas over the next decades in order to make a meaningful comparison to the replacement scenarios. Averaged during that timeframe, natural gas is expected to cost significantly more than it does today.

Scenario 1 would replace all the aging natural gas plants with an equal amount of new natural gas plants. The net effect is still a much higher cost of electricity from the new plants, ranging between 30.3 and 34.8 cents per kilowatt-hour in the scenario model. This would eliminate the damage to sea life, and is assumed to reduce climate damage by 20 percent; thus the external cost is reduced relative to the aging plants. Even after the externalities regarding marine life and climate are taken into account, the electricity from new natural gas plants will still cost much more than from the aging plants. In the worst case, the total cost of running the replacement plants would be about 39 cents per kilowatt-hour. It is noteworthy that this range is actually much lower that what has been calculated by the California Energy Commission. Based on a survey of natural gas power plants in the state,

Table 19

Summary Comparison of Report Scenarios

Scenario	Capacity Megawatts	ELCC Megawatts	Annual Generation Megawatt Hours	Internal Cost Rate per Kilowatt Hour	External Cost Rate per Kilowatt Hour	Total Cost Rate per Kilowatt Hour	Annual Cost
Current Aging Plants							
Aging Plants Low Cost	15,400	15,400	12,152,397	$0.133	$0.023	$0.156	$1,895,773,932
Aging Plants High Cost	15,400	15,400	12,152,397	$0.202	$0.100	$0.302	$3,670,023,894
Replacement Scenario 1							
All Natural Gas Low Cost	15,400	15,400	12,152,397	$0.303	$0.006	$0.309	$3,755,090,673
All Natural Gas High Cost	15,400	15,400	12,152,397	$0.348	$0.044	$0.392	$4,763,739,624
Replacement Scenario 2 (High Cost)							
Green Energy–Generation Only	18,700	10,800	36,012,360	$0.289		$0.289	$10,412,991,337
Green Energy–with Efficiency	23,400	15,500	51,352,872	$0.211		$0.211	$10,860,848,545
Replacement Scenario 2 (Low Cost)							
Green Energy–Generation Only	18,700	10,800	36,012,360	$0.224		$0.224	$8,072,791,672
Green Energy–with Efficiency	23,400	15,500	51,352,872	$0.169		$0.169	$8,686,454,806

they show a range between 30 and 60 cents per kilowatt-hour.

The reduction in climate damage is based on having the new plants limited to generating the same amount of electricity as the current aging plants. This is unlikely, given pressure from a few key factors. First, the higher efficiency will mean that it will be profitable to sell power more hours in the year. Second, the aging plants are all depreciated in value and thus have little capital cost to recover; however, the owners of the new plants will need to recoup their sizable investment plus a rate of profit that is commonly near 15 percent per year on the equity share. Third, a new plant will be online and available more often than an aging plant that needs more frequent servicing.

The result of all of these factors could be that a new plant may generate more electricity than the plant it replaces. The effect of operating at a higher capacity factor will lower the energy cost per kilowatt-hour. But this will also mean burning more fuel, emitting more pollutants, and increased level of greenhouse gas emissions that will easily exceed the benefits from the "more efficient" power plant. On the other hand, if the plants operate only at a 5 percent capacity, as the California Energy Commission has projected, the environmental damage and fuel consumption will be much less. However, the average cost of energy will be much higher—up to 60 cents per kilowatt-hour—due to the need to recover capital expenses through fewer kilowatt-hours. This places the new natural gas plants in something of a Catch-22.

Scenario 2 would replace the aging plants with a green energy portfolio, which includes both generation and energy efficiency components. Since these do not appear on the same part of the utility bill, the cost of the "supply only" component is shown separately at 27.4 cents per kilowatt-hour. This is clearly less than the cost of electricity from new natural gas plants. The savings from building a green portfolio are even greater if the avoided external cost is taken into account.

Energy efficiency makes up a sizable portion of the portfolio. Since it is by far the cheapest resource, at only 6 cents per kilowatt-hour, it reduces the average cost of the green portfolio to 21.2 cents per kilowatt-hour. This is far less expensive than any of the natural gas replacement alternatives, with or without externalities. The Green Energy scenario cost falls just above the high end of the aging plants if only internal cost is considered. If externalities are taken into account, the Green Energy portfolio—including energy efficiency—falls toward the lower range of cost of energy from the aging plants.

The total cost of energy—as opposed to the cost per kilowatt-hour—is much higher for Scenario 2, ranging from $9.8 to $10.9 billion per year. It is important to realize that this is because it is generating 3 to 4 times as much electricity as the current aging plants or the model projection for replacement Scenario 1. The higher generation rate is achieved because the renewable resources will generate much more energy to provide the same 15,400 megawatt effective load carrying capacity as the aging plants.

Unquantified Impacts

This study does not provide an exhaustive quantification of all possible benefits that aggressive implementation of solar power and shutdown of aging plants would achieve. Other major unquantified benefits include:

Environmental Justice

The public health, economic and aesthetic impacts of a large power plant on an entire neighborhood, especially a low-income neighborhood, could be substantially more than the sum of the parts. Such plants tend to spill over to affect the quality of life for an entire community. The immediate surrounding populations of large power plants such as Potrero, Haynes, Alamitos, and Huntington Beach have a high percentage of low-income, minority individuals. Rarely, if ever, are large, polluting, industrial power plants placed in or near affluent neighborhoods with white populations. In general, richer communities would be very concerned that proximity to a power plant will reduce real estate values and create other damages to the quality of life. The economic suppression of neighborhoods near power plants creates an environmental justice problem that goes beyond the direct pollution and public health costs of aging power plants.[88]

Encouraging Renewables/Lessening Dependence on Fossil Fuels

California's Energy Action Plan recognizes the need to lessen dependence on fossil fuels by placing energy efficiency and development of renewables at a higher priority than conventional fuel sources. At the same time, the state is requiring dramatic reductions in greenhouse gas emissions under AB32, the Global Warming Solutions Act. A new natural gas plant constructed in 2010 could operate until 2050, reinforcing the state's dependence on natural gas for forty years. Uncertainty about the future price and supply of natural gas makes this approach quite risky. Development of renewables, however, will increase the competitiveness and availability of clean energy options while simultaneously reducing greenhouse emissions. As the need to wean our economies off fossil fuels becomes ever more pressing, the long-term sustainability of solar power becomes an ever stronger argument in its favor.

Recreational Value of California's Coast

Tourism and recreation are the greatest economic generators along the California coast. In 2003, total expenditures associated with beach recreation exceeded $13 billion, consumer surplus values associated with beach recreation may exceed $5 billion annually, and recreational fishing generated another $2.25 billion in revenue. It is hard to know how the elimination of power plants would change this equation, but some of the power plants are located near heavily used recreation and tourism areas which could potentially be expanded. In addition, the lack of once-through cooling power technology could improve commerical and recreational fishing conditions.[89]

Lifecycle Impacts

This report does not take into account the environmental and social costs of the entire lifecycle of electricity production. For instance, extraction of natural gas from gas fields has land use and water impacts that are necessary as long as the natural gas is needed for power plants. The production of solar panels also has environmental costs in terms of emissions and of electricity use, though these impacts only occur at the time of production. Unlike natural gas, impacts with solar do not continue with the life of the panels. While quantifying the costs of lifecycle impacts would make this analysis more robust, the scope of this report only covers the impacts at the point of generation.

Green Energy Replacement is Cost Effective and Consistent with State Law

By applying its policy tools, California can retire its aging natural gas power plants while achieving significantly lower levels of greenhouse gas emissions, air pollution, and natural gas consumption. Among the most important policies are the state's mandate to increase renewable energy to 20 percent by 2010, and increasing renewables to 33 percent by 2020 as required by the Energy Action Plan, the AB 32 Scoping Plan and the Governor's executive order. A 33 percent renewable energy supply would allow a large amount of the state's natural gas power plants—about 10,000 megawatts—to be retired.[90] The state has also adopted aggressive requirements for energy efficiency and conservation that have the aim of reducing 4,500 megawatts of future demand by 2020, a goal that state regulators expect to exceed.[91] In addition, there are demand reduction programs, such as demand response and interruptible load that should reduce even further the need for the peaking service the aging natural gas plants provide. Replacing the aging power plants with new natural gas plants is thus at odds with achieving the state targets for a range of green energy programs.

Continuing to rely heavily on natural gas power plants may be technically and conceptually easier for grid operators than moving to renewable energy, and we will continue to need some amount of natural gas power for decades into the future. Yet, if the state is to achieve its environmental and policy goals, alternative ways of meeting our future energy needs must be given a higher priority than taking the technically easier path. The challenges of climate change and depletion of fossil fuels increasingly make it necessary to surmount the technical challenges of moving to an electric power grid that depends on renewable energy.

A confluence of events is creating an opportunity to change how we meet our energy needs. An impressive raft of policies, rules and legislation in California are aiming to address global warming, increase environmental protection, reduce dependency on fossil fuels, and secure a stable and economical energy supply for the future. These mandates could have a dramatic impact on California's need for electricity generated from natural gas:

- AB 32, California's Global Warming Solutions law mandates rolling back carbon dioxide emissions to 1990 levels by 2020, equivalent to a reduction of about 25 percent.
- The Renewable Portfolio Standard requires all utilities to obtain at least 20 percent of their electric energy needs from renewable sources by 2010.
- The Energy Action Plan sets a goal of 33 percent renewable energy by 2020.
- The California Solar Initiative commits $3 billion to subsidizing the construction of 3,000 megawatts of rooftop solar installations by 2017.
- Energy Efficiency programs have been ramped up over the last few years to a total state budget of nearly $1 billion per year to reduce electricity consumption.
- Utilities are required to procure 5 percent of their peak capacity needs by reducing their customers' peak demand, *in addition to energy efficiency savings*.

As the state contemplates retirement of aging natural gas power plants, it is important to keep in mind that there are a number of opportunities for meeting California's energy needs with alternatives to conventional power generation. These include preferred resources in the "Loading Order," which is the state's priority rankings of energy resources: 1) Energy Efficiency and Demand Reduction, 2) Renewables and Distributed Generation (i.e., local or on-site), and last 3) clean fossil fuel. The need to enforce this order has become more acute under the pressure of AB 32's mandate to decrease greenhouse gas emissions.

The higher loading order resources are potentially quite large. About 30 percent of normal summer peak demand, nearly 15,000 megawatts, is driven directly by air conditioning. There is great potential to reduce this need through more efficient technologies such as geothermal heat pumps, better home insulation, "cool roofs" that reflect the heat rather than absorb it, timed cycling of air conditioners, and shade trees. Only a fraction of the resources of renewable energy and demand reduction have been tapped.

Implementation of California's goal to get 33 percent of its electricity from renewable sources and deployment of demand side resources would displace the need for over 15,000 megawatts or more of natural gas power plants, and can eliminate the need for replacing aging power plants with new fossil fuel units. Certain technologies, such as solar energy and peak demand reduction programs, can effectively match most of the benefits of natural gas power plants that are used to meet peak energy needs.

Significant quantities of these green resources can be deployed in the regions where they are needed for grid reliability. Clean energy plans for San Francisco, San Diego and the LA Basin have shown that there is a green energy path to the future.

Resource decisions are made at the California Public Utilities Commission, and by utility companies, according to "least cost" criteria. For example, when energy efficiency measures are evaluated, they are compared to the cost of generating comparable amounts of electricity. If the efficiency measure is less costly, then it will be prioritized. The same is true of contracts for renewable energy. Contracts are signed and power plants are "dispatched" according to the cost ranking. If full and realistic costs are imposed on environmentally destructive practices, like once-through cooling (OTC) and carbon emissions, then priority will shift toward resources that are less destructive. Thus policy-makers do not need to wait passively for an abstract "market" to take the lead on energy decisions, particularly when that market has not internalized the proper costs into its assessments.

We recommend applying the following guiding principles:

- Project appropriate internal and external costs onto the power plant, rather than on future ratepayers, those who pay with loss of health, or on the natural environment.
- A single fixed projection does not give a correct picture of the future cost of natural gas; thus the market price referent should be replaced with alternatives that better characterize risk.
- Market based assessments of environmental cost should be supplemented by econometric projections of future climate damages that account for the ethical implications of our choices.
- Retirement of aging plants should be timed to deployment of new clean energy resources; this will minimize cost and is most protective of the future environment.

Glossary of Acronyms

AB 32 California's Global Warming Solutions Act of 2006

AFRR Annual Fixed Revenue Requirement; fixed cost required to keep a facility, such as a power plant, in existence. Does *not include* fuel or other costs that depend on how much the plant is operated.

APF Area of Production Forgone; measure of loss of ocean resource

BBEES Big Bold Energy Efficiency Strategies; new California initiative for achieving maximum economic potential for energy efficiency savings

BTU British Thermal Unit; the amount of energy needed to heat one pound of water one degree Fahrenheit.

BUGs Back-Up Generators; usually small diesel or natural gas electric generators

CAISO California Independent System Operator

CC Combined Cycle turbine for powering a generator in an electric power plant, recycles waste heat into secondary steam heat recovery systems to generate more power and greatly increase efficiency.

CEC California Energy Commission

CF Capacity Factor; percent of power plant utilization

CO_2 Carbon Dioxide, main global warming gas

CO_2e Carbon Dioxide Equivalent; mass of greenhouse gases translated into the equivalent amount of Carbon Dioxide, adjusting for the relative warming power of the gas.

CPUC California Public Utilities Commission

CSI California Solar Initiative; $3 billion, 10-year program to install 3000 megawatts of onsite or rooftop solar power.

CSP Concentrating Solar Power, uses heat of the sun to generate electricity

DG Distributed Generation; electric generation located in the distribution system, including at the site of energy consumption.

DR Demand Response; market based method for reducing peak demand during a power emergency.

ELCC Effective Load Carrying Capacity, reliable capacity of a power plant

EPA US Environmental Protection Agency

GW Gigawatt; one billion watts or 1000 megawatts

I&E Impingement and Entrainment; destruction of sea life by infrastructure such as power plants that use ocean water for cooling

IL Interruptible Load; a method of reducing demand for electricity using mechanical controls of electrical devices during a power emergency.

IOUs Investor-Owned Utilities; in California includes PG&E, SCE, SDG&E

KW Kilowatt; one thousand watts of power

KWh Kilowatt-hour, energy output resulting from 1000 watts of power exerted for one hour, or any mathematical equivalent such as 1 watt for 1000 hours.

LBNL Lawrence Berkeley National Laboratory

MMBTU Million British Thermal Units, very close to 1000 cubic feet of natural gas

MPR Market Price Referent, the projected cost of generating electricity using natural gas fuel in a baseload combined cycle power plant.

MW Megawatt; one million watts or one thousand kilowatts

MWh Megawatt-hours; energy equivalent to one million watts of power exerted for a period of one hour

NOx Nitrous Oxide; a greenhouse gas and air pollutant that converts to ozone

O&M Operation and Maintenance

OTC Once Through Cooling, hot water is expelled from the plant into the ocean

PM Particulate Matter; air pollutant

PV Photovoltaics; cells or panels made of semiconductor materials that convert light directly into electricity.

RETI Renewable Energy Transmission Initiative

RMR Reliability Must-Run; contracts for power with CAISO

SC Single Cycle turbine that powers generators in electric power plants

SCR Selective Catalytic Reduction, an air pollution control device for greatly reducing NOx emissions to required levels.

SEPs Supplemental Energy Payments, a former account used to pay excess (so-called "above market") costs for renewable energy.

SWRCB State Water Resources Control Board

TCF Thousand Cubic Feet; a standard market unit measure for natural gas that has very close to the energy content of one million btu's.

USDA United States Department of Agriculture

VSL Value of Statistical Life

Appendix 1

New California Natural Gas Power Plants Built and Under Construction

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 4/24/2009

	Projects On Line (Arranged By Online Date)	Docket Number	Status	Capacity (MW)	Const. Completed (%)	Location	Date Approved	Const. Start Date	Original OnLine Date	Current / Actual Online Date
1a	Sunrise Simple Cycle - Texaco & Edison Mission E.	1998-AFC-04		320	100	Kern	12/06/2000	12/07/2000	07/01	06/27/2001
2	Sutter - Calpine	1997-AFC-02		540	100	Sutter	04/14/1999	07/01/1999	07/01	07/02/2001
3	Los Medanos - Calpine	1998-AFC-01		555	100	Contra Costa	08/17/1999	09/17/1999	07/01	07/09/2001
4	*Wildflower Larkspur - Intergen*	*2001-EP-01*		*90*	*100*	*San Diego*	*04/04/2001*	*04/05/2001*	*07/01*	*07/16/2001*
5	*Wildflower Indigo - Intergen*	*2001-EP-02*		*135*	*100*	*Riverside*	*04/04/2001*	*04/05/2001*	*07/01*	*09/10/2001*
6	*Drews - Alliance*	*2001-EP-05*		*40*	*100*	*San Bernardino*	*04/25/2001*	*04/26/2001*	*09/01*	*08/15/2001*
7	*Hanford - GWF*	*2001-EP-07*		*95*	*100*	*Kings*	*05/10/2001*	*05/11/2001*	*09/01*	*09/01/2001*
8	*Century - Alliance*	*2001-EP-04*		*40*	*100*	*San Bernardino*	*04/25/2001*	*04/26/2001*	*09/01*	*09/15/2001*
9	*Escondido - Calpeak*	*2001-EP-10*		*50*	*100*	*San Diego*	*06/06/2001*	*06/07/2001*	*09/01*	*09/30/2001*
10	*Border - Calpeak*	*2001-EP-14*		*50*	*100*	*San Diego*	*07/11/2001*	*07/12/2001*	*09/01*	*10/26/2001*
			Subtotal On Line 2001	*1,914*						
11	*King City - Calpine*	*2001-EP-06*		*50*	*100*	*Monterey*	*05/02/2001*	*05/03/2001*	*09/01*	*01/14/2002*
12	*Gilroy I - Calpine*	*2001-EP-08*		*135*	*100*	*Santa Clara*	*05/21/2001*	*05/22/2001*	*09/01*	*02/20/2002*
13	Delta - Calpine	1998-AFC-03		887	100	Contra Costa	02/09/2000	04/01/2000	07/02	05/10/2002
14	Henrietta Peaker - GWF	2001-AFC-18		96	100	Kings	03/05/2002	03/08/2002	06/02	07/01/2002
15	Moss Landing - L.S. Power	1999-AFC-04		1,060	100	Monterey	10/25/2000	11/28/2000	06/02	07/11/2002
16a	Huntington Beach Unit 3 - AES	2000-AFC-13		225	100	Orange	05/10/2001	05/31/2001	11/01	07/31/2002
17	Valero Cogen (Unit 1) - Valero	2001-AFC-05		51	100	Solano	10/31/2001	11/05/2001	06/02	10/18/2002
			Subtotal On Line 2002	*2,504*						
18	La Paloma - Complete Energy Holdings	1998-AFC-02		1,124	100	Kern	10/06/1999	01/01/2000	03/02	03/07/2003
19	Los Esteros Simple Cycle - Calpine	2001-AFC-12		180	100	Santa Clara	02/07/2002	07/08/2002	05/03	03/07/2003
	Los Esteros Simple Cycle recertification - Calpine	2003-AFC-02		0	100	Santa Clara	03/16/2005	07/08/2002	05/03	03/07/2003
20	High Desert - Constellation	1997-AFC-01		830	100	San Bernardino	05/03/2000	05/01/2001	07/03	04/22/2003
21	Tracy Peaker - GWF	2001-AFC-16		169	100	San Joaquin	07/17/2002	07/22/2002	04/03	06/01/2003
1b	Sunrise Comb. Cycle Amendment - Texaco & Edison Mission E.	1998-AFC-04C		265	100	Kern	11/19/2001	12/21/2001	06/03	06/01/2003
22	Woodland II - Modesto Irrigation District	2001-SPPE-01		80	100	Stanislaus	09/19/2001	02/21/2002	05/03	06/06/2003
23	Blythe I - FPL	1999-AFC-08		520	100	Riverside	03/21/2001	04/27/2001	04/03	07/15/2003
24	Elk Hills - Sempra & Oxy	1999-AFC-01		500	100	Kern	12/06/2000	06/08/2001	12/02	07/24/2003
16b	Huntington Beach Unit 4 - AES	2000-AFC-13		225	100	Orange	05/10/2001	05/31/2001	11/01	08/07/2003
			Subtotal On Line 2003	*3,893*						
25	Donald Von Raesfeld Power Plant (Pico) - Silicon Valley Power	2002-AFC-03		147	100	Santa Clara	09/09/2003	09/10/2003	12/04	03/24/2005
26	Pastoria - Calpine	1999-AFC-07		750	100	Kern	12/20/2000	10/03/2001	01/03	07/05/2005
27	Metcalf - Calpine	1999-AFC-03		600	100	Santa Clara	09/24/2001	01/15/2002	07/03	05/27/2005
28	Kings River - Kings River Cons. Dist.	2003-SPPE-02		97	100	Fresno	05/19/2004	11/01/2004	05/05	09/19/2005
29	Magnolia - So. Ca. Power Producers	2001-AFC-06		328	100	Los Angeles	03/05/2003	07/21/2003	05/05	09/22/2005
30	Malburg - City of Vernon	2001-AFC-25		134	100	Los Angeles	05/20/2003	09/11/2003	11/05	10/17/2005
31a	Mountainview Unit 3 - SCE	2000-AFC-02		528	100	San Bernardino	03/21/2001	09/01/2001	06/03	12/09/2005
			Subtotal On Line 2005	*2,584*						
31b	Mountainview Unit 4 - SCE	2000-AFC-02		528	100	San Bernardino	03/21/2001	09/01/2001	06/03	01/19/2006
32	Cosumnes - SMUD	2001-AFC-19		500	100	Sacramento	09/09/2003	10/31/2003	06/05	02/24/2006
33	Walnut - Turlock Irr. Dist.	2002-AFC-04		250	100	Stanislaus	02/18/2004	03/15/2004	04/06	02/28/2006
34	Palomar Escondido - SDG&E	2001-AFC-24		546	100	San Diego	08/06/2003	06/01/2004	03/06	04/01/2006
35	Riverside En. Res. Cntr. Units 1 & 2 - City of Riverside	2004-SPPE-01		96	100	Riverside	12/15/2004	02/23/2005	11/05	06/01/2006
36	Ripon - Modesto Irrigation Dist	2003-SPPE-01		95	100	San Joaquin	02/04/2004	04/01/2005	04/05	06/21/2006
			Subtotal On Line 2006	*2,015*						
37	Bottle Rock Geothermal Restart	1979-AFC-4C		17	100	Lake	12/13/2006	12/19/2006	06/07	10/01/2007
38	Roseville Combined Cycle - Roseville Electric	2003-AFC-01		160	100	Placer	04/13/2005	08/18/2005	12/07	11/07/2007
			Subtotal On Line 2007	*177*						
39	Niland Peaker - IID	2006-SPPE-1		93	100	Imperial	10/11/2006	6/25/2007	06/08	05/29/2008
			Subtotal On Line 2008	*93*						
40	Gateway - PG&E	2000-AFC-01		530	**99**	Contra Costa	5/30/2001	8/30/2001 Resumed: 2/2007	08/03	1/4/2009
41	Inland Empire - GE	2001-AFC-17		400	**95** Unit 2 delayed	Riverside	12/17/2003	8/26/2005	12/05	**unit 1: 1/28/09 400 MW** **unit 2: 10/09 400 MW**
			Subtotal On Line 2009	*930*						

ON-LINE TOTAL 14,110

	Approved / Under Construction (Arranged By Online Date)	Docket Number	Status	Capacity (MW)	Const. Completed (%)	Location	Date Approved	Const. Start Date	Original OnLine Date	Current / Actual Online Date
1	Starwood Midway - Starwood Power	2006-AFC-10	Under Construction	120	**99**	Fresno	1/16/2008	9/23/2008	06/09	05/09
2	EIF Panoche - Energy Investors Fund	2006-AFC-5	Under Construction	400	**90**	Fresno	12/19/2007	2/15/2008	11/09	08/09
3	Otay Mesa - Calpine	1999-AFC-05	Under Construction	590	85	San Diego	4/18/2001	5/01/2007	07/03	10/09
4	Humboldt Power Plant - PG&E	2006-AFC-7	Under Construction	163	**22**	Humboldt	9/24/2008	10/11/2008	09/09	07/10
5	Colusa Generation Station - PG&E	2006-AFC-9	Under Construction	660	**23**	Colusa	4/23/2008	7/28/2008	06/10	10/10
			Under Construction Subtotal	***1,933***						

Projects Not Approved (Arranged By Decision Date)	Docket Number	Process	Capacity (MW)	Project Type	Location	Date Filed	Decision Date		
Eastshore - Tierra Energy	2006-AFC-6	12-mon AFC	116	Brownfield	Alameda	09/22/2006	10/08/2008		

NOT APPROVED TOTAL 116

Appendix 2

Surcharges for Natural Gas under the CPUC 2008 MPR Model, Tab: CA_Gas_Forecast

Cost in dollars per million British Thermal Units ($/mmbtu)

Natural Gas Forecast for MPR Baseload Proxy

	Year	NYMEX Futures Contract Average	Average HHub Fundamental Forecast	2008 MPR	Combined CA Basis Forecast	PG&E/SoCal Average Distribution Rate w/ Escalation	Average Franchise Fee Surcharge	Hedging Transaction Cost	MPR CA Gas Forecast (nominal$)	surcharges
	2008	$10.39	$9.35	$10.39	-$0.45	$0.396	$0.120	$0.082	$10.54	$1.05
1	2009	$10.47	$7.30	$10.47	-$0.47	$0.404	$0.121	$0.082	$10.60	$1.08
2	2010	$9.69	$7.50	$9.69	-$0.33	$0.412	$0.113	$0.082	$9.97	$0.93
3	2011	$9.40	$7.74	$9.40	-$0.33	$0.420	$0.109	$0.082	$9.68	$0.94
4	2012	9.25	$7.96	$9.25	-$0.33	$0.428	$0.108	$0.082	$9.54	$0.94
5	2013	9.14	$8.37	$9.14	-$0.33	$0.437	$0.106	$0.082	$9.44	$0.95
6	2014	9.12	$8.76	$9.12	-$0.33	$0.446	$0.106	$0.082	$9.43	$0.96
7	2015	9.19	$8.89	$9.19	-$0.33	$0.454	$0.107	$0.082	$9.50	$0.97
8	2016	9.27	$9.25	$9.27	-$0.33	$0.464	$0.108	$0.082	$9.60	$0.98
9	2017	9.39	$9.53	$9.39	-$0.33	$0.473	$0.109	$0.082	$9.73	$0.99
10	2018	9.55	$9.85	$9.55	-$0.33	$0.482	$0.111	$0.082	$9.90	$1.00
11	2019	9.72	$10.25	$9.72	-$0.33	$0.492	$0.113	$0.082	$10.08	$1.01
12	2020	9.89	$10.51	$9.89	-$0.33	$0.502	$0.115	$0.082	$10.27	$1.02
13	2021		$10.75	$10.04	-$0.19	$0.512	$0.119	$0.082	$10.56	$0.90
14	2022		$11.13	$10.39	-$0.22	$0.522	$0.123	$0.082	$10.90	$0.95
15	2023		$11.69	$10.91	-$0.24	$0.532	$0.129	$0.082	$11.41	$0.98
16	2024		$12.34	$11.52	-$0.27	$0.543	$0.136	$0.082	$12.02	$1.03
17	2025		$12.91	$12.05	-$0.26	$0.554	$0.142	$0.082	$12.56	$1.04
18	2026		$13.29	$12.40	-$0.28	$0.565	$0.146	$0.082	$12.91	$1.07
19	2027		$13.89	$12.96	-$0.29	$0.576	$0.153	$0.082	$13.48	$1.10
20	2028		$14.44	$13.48	-$0.31	$0.587	$0.159	$0.082	$14.00	$1.14
21	2029		$14.95	$13.95	-$0.32	$0.599	$0.164	$0.082	$14.48	$1.17
22	2030		$15.49	$14.46	-$0.34	$0.611	$0.170	$0.082	$14.99	$1.20
23	2031		$16.02	$14.95	-$0.34	$0.623	$0.176	$0.082	$15.49	$1.22
24	2032		$16.54	$15.44	-$0.34	$0.636	$0.182	$0.082	$16.01	$1.24
25	2033		$17.07	$15.94	-$0.34	$0.648	$0.188	$0.082	$16.52	$1.25
26	2034		$17.33	$16.17	-$0.34	$0.661	$0.191	$0.082	$16.77	$1.27
27	2035		$17.86	$16.67	-$0.34	$0.674	$0.197	$0.082	$17.28	$1.29
28	2036		$18.39	$17.16	-$0.34	$0.688	$0.203	$0.082	$17.80	$1.31
29	2037		$18.91	$17.65	-$0.34	$0.701	$0.209	$0.082	$18.31	$1.33
30	2038		$19.44	$18.15	-$0.34	$0.715	$0.215	$0.082	$18.82	$1.35
31	2039		$19.97	$18.64	-$0.34	$0.730	$0.221	$0.082	$19.34	$1.37
32	2040		$20.50	$19.13	-$0.34	$0.744	$0.227	$0.082	$19.85	$1.39
33	2041		$21.03	$19.63	-$0.34	$0.759	$0.233	$0.082	$20.37	$1.41
34	2042		$21.56	$20.12	-$0.34	$0.774	$0.239	$0.082	$20.88	$1.43

Natural gas prices used in scenarios in this report are $6.21 and $10 per mmbtu for natural gas delivered to a power plant. The estimates are in a much lower range than the CPUC used in its 2008 MPR forecast which runs from a low of $9.44 in 2013 up to $20.88 in 2042. This encompasses the 30 year life of a photovoltaic or solar thermal plant put into operation in 2012.

While current (April, 2009) prices are particularly low, at about $3.50 per mmbtu, this is for the Henry Hub price in Louisiana. Delivered cost to California power plants is projected by the CPUC to range from a minimum of 93 cents to well over a dollar higher than the hub price over the next few decades.

Appendix 3
Cost of Energy from Aging Natural Gas Plants

Low Price Scenario: $6.00 per mmbtu natural gas

Plant	Capacity	heat rate	capacity factor	Generation 2005	Fuel Use	AFRR	Variable o&m	Fuel Cost	Internal Total
	MW	btu/kwh		MWh	mmbtu	per kwh	per kwh	per kwh	per kwh
Pittsburg	1370	11,192	5.4%	652,862	7,306,832	$0.116	$0.032	$0.067	$0.215
Contra Costa	680	10,775	5.6%	331,036	3,566,913	$0.135	$0.032	$0.065	$0.232
Alamitos	1950	11,715	7.7%	1,311,102	15,359,560	$0.040	$0.032	$0.070	$0.142
Huntington Beach	888	10,896	20.0%	1,554,597	16,938,889	$0.019	$0.032	$0.065	$0.116
Potrero	207	10,787	21.3%	385,621	4,159,694	$0.044	$0.032	$0.065	$0.141
Encina	929	11,688	22.9%	1,864,797	21,795,747	$0.024	$0.032	$0.070	$0.126
Above Combined	6024	11,332	11.6%	6,100,015	69,127,634	$0.043	$0.032	$0.068	$0.143
All Aging Powerplants	*15,414*	*11,094*	*9.0%*	*12,152,398*	*134,816,812*	*$0.043*	*$0.032*	*$0.067*	*$0.142*
Natural Gas price	$6.00	per mmbtu							

High Price Scenario: $10.00 per mmbtu natural gas

Plant	Capacity	heat rate	capacity factor	Generation 2005	Fuel Use	AFRR	Variable o&m	Fuel Cost	Internal Total
	MW	btu/kwh		MWh	mmbtu	per kwh	per kwh	per kwh	per kwh
Pittsburg	1370	11,192	5.4%	652,862	7,306,832	$0.116	$0.032	$0.112	$0.260
Contra Costa	680	10,775	5.6%	331,036	3,566,913	$0.135	$0.032	$0.108	$0.275
Alamitos	1950	11,715	7.7%	1,311,102	15,359,560	$0.040	$0.032	$0.117	$0.189
Huntington Beach	888	10,896	20.0%	1,554,597	16,938,889	$0.019	$0.032	$0.109	$0.159
Potrero	207	10,787	21.3%	385,621	4,159,694	$0.044	$0.032	$0.108	$0.184
Encina	929	11,688	22.9%	1,864,797	21,795,747	$0.024	$0.032	$0.117	$0.173
Above Combined	6024	11,332	11.6%	6,100,015	69,127,634	$0.043	$0.032	$0.113	$0.189
All Aging Powerplants	*15,414*	*11,094*	*9.0%*	*12,152,398*	*134,816,812*	*$0.043*	*$0.032*	*$0.111*	*$0.186*
Natural Gas price	$10.00	per mmbtu							

The power plants shown are a selection from the aging plants for which there is data on annual fixed revenue requirement (AFRR).

Appendix 4
CPUC "Carbon Adder" Schedule for Evaluating Renewables against Natural Gas Power

Model benchmark for "carbon adder"
with 2004 start @ $8/tonne & 5% annual increase

2004	$8.00	2022	$19.25
2005	$8.40	2023	$20.22
2006	$8.82	2024	$21.23
2007	$9.26	2025	$22.29
2008	$9.72	2026	$23.40
2009	$10.21	2027	$24.57
2010	$10.72	2028	$25.80
2011	$11.26	2029	$27.09
2012	$11.82	2030	$28.45
2013	$12.41	2031	$29.87
2014	$13.03	2032	$31.36
2015	$13.68	2033	$32.93
2016	$14.37	2034	$34.58
2017	$15.09	2035	$36.30
2018	$15.84	2036	$38.12
2019	$16.63	2037	$40.03
2020	$17.46	2038	$42.03
2021	$18.34	2039	$44.13

Appendix 5

Cost of Energy from New Central Station Solar Thermal Plants

Utility Scale Solarthermal System Financial Model

	capital & equity		
1	capital cost	$5.00	per watt (ac)
2	loan portion	60%	
3	loan amount	$3.00	per watt
4	rate	7.5%	
5	term	15	years
6	declining balance interest	$2.10	per watt
7	total loan	$0.90	per watt
8	annual loan payment	$0.06	per watt
9	equity	$2.00	per watt
10	equity rate of return (pretax)	15.00%	

	tax credit & depreciation		
11	federal tax credit	30%	
12	fed tax rate	33%	
13	state tax rate	7%	
14	total tax rate	40%	
15	depreciation tax value	$2.00	per watt
16	tax credit	$1.50	per watt
17	total tax benefits	$3.50	per watt

	lifecycle cost		
18	variable o&m rate	$0.000	per kwh
19	fixed o&m	$65	per kw-yr
20	fixed o&m	$1.95	per watt
21	fixed o&m	$0.027	per kwh
22	lifecycle	30	years

	electric generation		
23	generation rate	2500	kwh/kw (ac)
24	degrade rate	0.20%	per year
25	term rate	2354	
26	avg rate	2427	kwh/kw (ac)
27	lifecycle generation	72,814	kwh
28	capacity factor	27.71%	

	cash flow		
31	loan principal	$3.00	per watt
32	loan interest	$2.10	per watt
33	equity	$2.00	per watt
34	profit	$9.00	per watt
35	variable o&m	$0.00	per watt
36	fixed o&m	$1.95	per watt
37	lifecycle pretax cost	$18.05	per watt
38	tax benefits	-$3.50	per watt
39	net lifecycle cost (pretax)	$14.55	per watt

40	**Net Cost of Electricity**	**$0.200**	**per kwh**

The model assumes an upfront capital cost in the middle of the range assumed by RETI Phase 1-B report. Performance of projected RETI projects ranges between 25% and 32% capacity factor, and this model shows a mid-range assumption.

Appendix 6
Cost of Energy from New Utility Scale Photovoltaic Plants

Utility Scale Photovoltaic System Financial Model

	capital & equity		
1	capital cost	$7.00	per watt (ac)
2	loan portion	60%	
3	loan amount	$4.20	per watt
4	rate	7.5%	
5	term	15	years
6	declining balance interest	$2.94	per watt
7	total loan	$1.26	per watt
8	annual loan payment	$0.08	per watt
9	equity	$2.80	per watt
10	equity rate of return (pretax)	11.0%	

	tax credit & depreciation		
11	federal tax credit	30%	
12	fed tax rate	33%	
13	state tax rate	7%	
14	total tax rate	40%	
15	depreciation tax value	$2.80	per watt
16	tax credit	$2.10	per watt
17	total tax benefits	$4.90	per watt

	lifecycle cost		
18	o&m rate	$0.010	per kwh
19	inverter lifecycle	10	years
20	inverter lifecycle cost	$0.60	per watt
21	lifecycle	30	years

	electric generation		
22	generation rate (initial)	2000	kwh/kw (dc)
23	ac derate	85%	
24	ac generation rate	2353	kwh/kw (ac)
25	degrade rate	0.50%	per year
26	term rate	2024	
27	avg rate	2189	kwh/kw (ac)
28	lifecycle generation	65,661	kwh
29	capacity factor	25.0%	

	cash flow		
30	loan principal	$4.20	per watt
31	loan interest	$2.94	per watt
32	equity	$2.80	per watt
33	profit	$9.24	per watt
34	o&m	$0.30	per watt
35	inverter	$1.20	per watt
36	lifecycle pretax cost	$20.68	per watt
37	tax benefits	-$4.90	per watt
38	net lifecycle cost (pretax)	$15.78	per watt
39	**Net Cost of Electricity**	**$0.240**	**per kwh**

The model is similar to RETI in assuming a tracking photovoltaic system with relatively high capacity factor, and uses a similar cost and financing structure. Project size is assumed to be 20 megawatts, sized to fit near existing substations and should not require new transmission lines. RETI identified hundreds of suitable sites with a total potential over 20,000 megawatts.

Appendix 7
Cost of Electricity from Generation Technologies [92]

Table 2: Summary of Levelized Costs

In-Service Year =2007 (Nominal 2007$)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Conventional Combined Cycle (CC)	500	505.82	102.19	10.22	466.86	94.47	9.45	428.32	86.84	8.68
Conventional CC - Duct Fired	550	512.39	103.52	10.35	472.40	95.59	9.56	432.97	87.78	8.78
Advanced Combined Cycle	800	476.97	96.36	9.64	438.22	88.68	8.87	399.62	81.02	8.10
Conventional Simple Cycle	100	250.43	599.57	59.96	195.59	468.46	46.85	132.84	318.33	31.83
Small Simple Cycle	50	270.36	647.28	64.73	212.08	507.98	50.80	146.70	351.55	35.15
Advanced Simple Cycle	200	295.96	236.12	23.61	253.22	202.10	20.21	201.13	160.60	16.06
Integrated Gasification Combined Cycle (IGCC)	575	566.58	126.51	12.65	476.15	106.32	10.63	361.52	80.72	8.07
Advanced Nuclear	1000	862.70	118.25	11.83	757.78	103.87	10.39	664.78	91.12	9.11
Biomass - AD Dairy	0.25	924.52	143.61	14.36	826.57	128.39	12.84	800.93	109.77	10.98
Biomass - AD Food	2	450.97	70.05	7.00	350.30	54.41	5.44	218.82	33.99	3.40
Biomass Combustion - Fluidized Bed Boiler	25	866.25	118.72	11.87	793.99	108.82	10.88	839.92	115.12	11.51
Biomass Combustion - Stoker Boiler	25	810.99	111.15	11.12	745.45	102.17	10.22	799.74	109.61	10.96
Biomass - IGCC	21.25	849.18	123.66	12.37	768.58	111.92	11.19	744.82	108.46	10.85
Biomass - LFG	2	382.50	56.11	5.61	345.95	50.86	5.09	352.73	52.36	5.24
Biomass - WWTP	0.5	514.65	97.34	9.73	466.63	88.84	8.88	366.54	71.78	7.18
Fuel Cell - Molten Carbonate	2	886.11	114.66	11.47	910.60	117.83	11.78	754.94	97.69	9.77
Fuel Cell - Proton Exchange	0.03	1409.63	182.41	18.24	1281.28	165.80	16.58	1025.67	132.72	13.27
Fuel Cell - Solid Oxide	0.25	955.64	123.66	12.37	868.61	112.40	11.24	695.29	89.97	9.00
Geothermal - Binary	50	477.23	75.85	7.58	396.31	63.53	6.35	394.23	65.55	6.56
Geothermal - Dual Flash	50	453.91	73.66	7.37	379.23	62.07	6.21	384.36	65.26	6.53
Hydro - In Conduit	1	213.72	52.84	5.28	183.96	45.68	4.57	188.71	47.78	4.78
Hydro - Small Scale	10	567.71	138.74	13.87	481.05	118.08	11.81	347.96	87.09	8.71
Ocean Wave (Pilot)	0.75	1239.92	1030.50	103.05	1005.64	837.65	83.76	733.96	617.12	61.71
Solar - Concentrating PV	15	620.48	424.84	42.48	631.79	434.00	43.40	442.11	308.09	30.81
Solar - Parabolic Trough	63.5	497.33	277.30	27.73	504.17	281.37	28.14	355.71	199.31	19.93
Solar - Photovoltaic (Single Axis)	1	1035.07	704.98	70.50	1019.48	695.59	69.56	681.74	468.87	46.89
Solar - Stirling Dish	15	855.55	518.89	51.89	868.93	527.00	52.70	648.77	393.47	39.35
Wind - Class 5	50	245.94	84.24	8.42	196.08	67.16	6.72	179.19	61.38	6.14

Source: Energy Commission

Appendix 8
Meeting Energy Needs through Demand Side Programs [93]

Statewide Peak Load Projections and Demand-Side Targets 2004 - 2008

	2004	2005	2006	2007	2008
Statewide coincident peak demand	**53,896**	**54,500**	**55,487**	**56,195**	**57,090**
Incremental energy efficiency programs	108	262	483	792	1,208
Adjusted peak demand	**53,788**	**54,238**	**55,004**	**55,403**	**55,882**
Demand Response Programs					
IOU/CPA demand bidding programs	333	403	430	460	496
Direct load cycling programs	300	330	363	399	439
Critical peak pricing programs	133	389	734	1,080	1,425
Voluntary load reduction Programs	130	117	105	95	85
Total: Demand response programs	**896**	**1,239**	**1,632**	**2,034**	**2,445**
Net peak demand	**52,892**	**52,999**	**53,372**	**53,369**	**53,437**
Net peak demand +15% reserves	**60,826**	**60,949**	**61,378**	**61,374**	**61,452**

Appendix 9
RETI Projections from the Phase 1B Report, Appendix D., for Cost of Generation from a Sampling of Solar Thermal Projects

RETI Stakeholder Steering Committee
RETI Phase 1B - Economic Analysis of CREZ

Resource Area	State	CREZ	Name	Tech-nology	Type	MW	Capital Cost ($/kW)	Cap Factor (%)	Gen Cost ($/MWh)
Salton Sea/SD	CA	San Diego South	WI_7	Wind	Proxy	188	$2,627	35%	$95
SOUTHEAST CA									
Southeast CA	CA	Barstow	WI_39	Wind	Pre-ID	171	$2,369	30%	$103
Southeast CA	CA	Barstow	WI_40	Wind	Pre-ID	248	$2,475	32%	$99
Southeast CA	CA	Barstow	WI_41	Wind	Proxy	78	$2,664	29%	$121
Southeast CA	CA	Barstow	WI_42	Wind	Pre-ID	135	$2,657	29%	$124
Southeast CA	CA	Barstow	WI_43	Wind	Pre-ID	188	$2,633	30%	$116
Southeast CA	CA	Barstow	WI_44	Wind	Pre-ID	116	$2,258	29%	$106
Southeast CA	CA	Barstow	st22695	Solar Th.	Pre-ID	200	$4,765	27%	$155
Southeast CA	CA	Barstow	st22696	Solar Th.	Pre-ID	200	$4,778	27%	$156
Southeast CA	CA	Barstow	st22697	Solar Th.	Pre-ID	200	$4,804	27%	$156
Southeast CA	CA	Barstow	st22720	Solar Th.	Pre-ID	200	$4,961	27%	$160
Southeast CA	CA	Barstow	stm29171	Solar Th.	Pre-ID	200	$4,883	28%	$151
Southeast CA	CA	Barstow	stm29582	Solar Th.	Pre-ID	200	$5,008	28%	$156
Southeast CA	CA	Iron Mountain	WI_18	Wind	Pre-ID	62	$2,660	28%	$131
Southeast CA	CA	Iron Mountain	st16821	Solar Th.	Pre-ID	200	$4,808	28%	$153
Southeast CA	CA	Iron Mountain	st16843	Solar Th.	Pre-ID	200	$4,893	28%	$155
Southeast CA	CA	Iron Mountain	st16844	Solar Th.	Pre-ID	200	$4,891	28%	$155
Southeast CA	CA	Iron Mountain	st16845	Solar Th.	Pre-ID	200	$4,850	28%	$154
Southeast CA	CA	Iron Mountain	st16868	Solar Th.	Pre-ID	200	$4,887	27%	$156
Southeast CA	CA	Iron Mountain	st16869	Solar Th.	Pre-ID	200	$4,886	27%	$156
Southeast CA	CA	Iron Mountain	st16893	Solar Th.	Pre-ID	200	$4,870	27%	$156
Southeast CA	CA	Iron Mountain	st16977	Solar Th.	Pre-ID	200	$4,978	26%	$166
Southeast CA	CA	Iron Mountain	st17022	Solar Th.	Pre-ID	200	$5,004	26%	$166
Southeast CA	CA	Iron Mountain	st17023	Solar Th.	Pre-ID	200	$4,880	26%	$163
Southeast CA	CA	Iron Mountain	st17101	Solar Th.	Pre-ID	200	$4,839	27%	$157
Southeast CA	CA	Iron Mountain	st17124	Solar Th.	Pre-ID	200	$4,913	27%	$159
Southeast CA	CA	Iron Mountain	st17125	Solar Th.	Pre-ID	200	$4,839	27%	$157
Southeast CA	CA	Iron Mountain	st17239	Solar Th.	Pre-ID	200	$4,884	27%	$158
Southeast CA	CA	Iron Mountain	st17241	Solar Th.	Pre-ID	200	$4,883	27%	$158
Southeast CA	CA	Iron Mountain	st17242	Solar Th.	Pre-ID	200	$4,763	27%	$155
Southeast CA	CA	Iron Mountain	st17263	Solar Th.	Pre-ID	200	$4,844	27%	$157
Southeast CA	CA	Iron Mountain	st17265	Solar Th.	Pre-ID	200	$4,758	27%	$155
Southeast CA	CA	Iron Mountain	st17266	Solar Th.	Pre-ID	200	$4,740	27%	$154
Southeast CA	CA	Iron Mountain	st17289	Solar Th.	Pre-ID	200	$4,789	27%	$156
Southeast CA	CA	Iron Mountain	st23690	Solar Th.	Pre-ID	200	$4,862	26%	$162
Southeast CA	CA	Iron Mountain	st23691	Solar Th.	Pre-ID	200	$4,906	26%	$163
Southeast CA	CA	Iron Mountain	st23714	Solar Th.	Pre-ID	200	$4,891	26%	$163
Southeast CA	CA	Iron Mountain	st23715	Solar Th.	Pre-ID	200	$4,832	26%	$161

Appendix 10
US Energy Information Administration 2009 Updated Natural Gas "Reference Case" Price Forecast to 2030

Report: An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook
SR/OIAF/2009-03
Scenario: Stimulus d041409a with American Recovery and Reinvestment Act
Table 13. Natural Gas Prices

Natural Gas Prices	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
(nominal dollars per million Btu)																									
Henry Hub Spot Price	6.73	6.96	8.86	4.33	5.30	5.75	5.96	6.21	6.54	6.96	7.37	7.80	8.26	8.82	9.49	10.06	10.34	10.32	10.57	10.72	11.14	11.78	12.59	13.24	13.97
Average Lower 48 Wellhead Price 10/	6.31	6.22	7.84	4.01	4.68	5.08	5.27	5.49	5.78	6.15	6.51	6.89	7.29	7.79	8.38	8.88	9.13	9.12	9.34	9.47	9.84	10.41	11.12	11.70	12.34
(nominal dollars per thousand cubic feet)																									
Average Lower 48 Wellhead Price 11/	6.49	6.39	8.06	4.12	4.81	5.23	5.41	5.64	5.94	6.33	6.69	7.09	7.50	8.01	8.62	9.13	9.39	9.37	9.60	9.74	10.12	10.70	11.43	12.03	12.68
Delivered Prices																									
(nominal dollars per thousand cubic feet)																									
Residential	13.71	13.05	13.63	11.37	11.94	12.40	12.46	12.58	12.83	13.18	13.71	14.29	14.90	15.59	16.39	17.13	17.67	17.79	18.14	18.49	19.16	19.99	20.94	21.79	22.71
Commercial	11.91	11.30	11.91	9.45	10.10	10.52	10.62	10.76	11.04	11.42	11.92	12.46	13.03	13.69	14.46	15.15	15.65	15.76	16.09	16.38	17.00	17.80	18.70	19.50	20.37
Industrial 4/	7.96	7.73	9.25	5.14	5.87	6.29	6.42	6.62	6.94	7.35	7.74	8.15	8.58	9.11	9.75	10.28	10.64	10.62	10.85	10.95	11.39	12.02	12.79	13.42	14.14
Electric Power 7/	7.06	7.22	9.32	4.83	5.47	5.89	6.03	6.16	6.46	6.84	7.23	7.62	8.06	8.58	9.17	9.71	10.06	10.05	10.34	10.48	10.91	11.52	12.27	12.87	13.57
Transportation 8/	15.56	15.93	17.74	13.57	14.40	14.93	15.12	15.40	15.83	16.38	16.90	17.46	18.05	18.72	19.51	20.20	20.72	20.83	21.21	21.52	22.15	22.96	23.87	24.66	25.54
Average 12/	9.51	9.26	10.70	7.18	7.93	8.35	8.51	8.68	8.99	9.38	9.82	10.29	10.78	11.35	12.04	12.62	13.02	13.02	13.28	13.45	13.95	14.64	15.47	16.18	16.95

http://www.eia.doe.gov/oiaf/servicerpt/stimulus/aeostim.html

Endnotes

1 Privately owned public service monopolies regulated by state public utility commissions.

2 Renewables Portfolio Standard Quarterly Report, California Public Utilities Commission, July 2008.

3 American Wind Energy Association (AWEA)

4 Renewables Portfolio Standard Quarterly Report, California Public Utilities Commission, July 2008. p. 7.

5 Source data for the chart is in Appendix 1, from the California Energy Commission's Energy Facility Status database. The column on the far right adds in plants that are outside the jurisdiction of the commission's approval process. These are primarily plants under 50 megawatts built between 2000 and 2007.

6 California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios, CERTS, LBNL, 2003. CEC, 500-03-106. The original study, however, shows only 32,100 megawatts of existing natural gas plants due to the fact that the report dates to 2003. Since that time thousands of megawatts of new plants have been built, as the previous chart illustrates.

7 California Power Plant Database (Excel File), http://energyalmanac.ca.gov/powerplants/POWER_PLANTS.XLS

8 ICF Jones & Stokes. *Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California*. Prepared for California Ocean Protection Council and State Water Resources Control Board. April 2008

9 California Energy Commission, "Integrated Policy Energy Report 2007," Page 95.

10 Intergovernmental Panel on Climate Change. IPCC Working Group III Fourth Assessment Report. May 2007. Summarized at http://www.ucsusa.org/global_warming/science_and_impacts/science/findings-of-the-ipcc-fourth-1.html

11 Coal generation in the US produced 1,994,385 gigawatt-hours or 48.5% of electricity, while natural gas produced 876,948 gigawatt-hours, or 21.3% out of a total 4,114,880 gigawatt-hours. Energy Information Administration data, http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html

12 CA Senate Bill 1368 (Stats. 2006, Ch. 598),

13 In 2002, California utilities claimed 4,744 megawatts of out-of-state capacity from six western coal plants. Source: A Preliminary Environmental Profile of California's Imported Electricity, Staff Report, California Energy Commission, June 2005. CEC-700-2005-017. In addition, there are 400 megawatts of in-state coal plant capacity. Since that time, the 1636 megawatt Mohave Generating Station retired, and several public utilities—Azusa, Colton, Glendale, Banning and IID—were pressed to let go of their shares in the San Juan Generating Station. Current ownership shares are shown at: http://www.pnm.com/systems/sj-owners.htm .

14 Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004, California Energy Commission, Final Staff Report, December 2006. CEC-600-2006-0130-SF, data in tables has 26.49 mmtco2e in the residential sector, 11.3 in commercial, 30.41 industrial, 47.14 electricity generation, 14.84 for refinery still gas, and a small amount from other natural gas and LPG sources. In addition, 7.5% of the state's natural gas power is imported, and this is not accounted for in the data above.

15 In 2007, 5,851,613 million cubic feet of natural gas production in the US was associated with oil extraction; this was 23.8% of extracted natural gas. Energy Information Administration data. http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm

16 Power Plant Fact Sheet, California Energy Commission Media Office, Updated: 5/7/08.

17 More recently there was an increase in natural gas consumption in the sector due to low hydroelectric power resources in exceptionally hot, dry years. This causes increased reliance on the least efficient natural gas plants to replace the lost hydropower.

18 Nameplate efficiency ratings are given according to the lower heating value (LHV), while in actual operation a plant will burn fuel according to its higher heating value (HHV) which is less efficient. In addition, power plants perform at less than the rated efficiency for reasons including age, hot weather, and non-optimal operation.

19 New General Electric Combined Cycle turbines operating in "Simple Cycle" mode range between 9250 and 10,642 btu/kwh, with the most efficient model being the MS9001FA. Source: Gas Turbine and Combined Cycle Products, GE Power Systems.

20 Comparative Cost of Central Station Electricity Generation Technologies, California Energy Commission, December 2007.

21 California Air Resources Board. Climate Change Draft Scoping Plan – June 2007 Discussion Draft.

22 California Energy Commission, "Integrated Energy Policy Report," 2007.

23 State Water Resources Control Board, Notice of Public Hearing. www.waterboards.ca.gov

24 Totals derived from California Power Plants Database, California Energy Commission. http://www.energy.ca.gov/database/POWER_PLANTS.XLS

25 Some of these plants list oil, diesel or distillate as alternate fuels, however nearly all the capacity runs on natural gas.

26 This figure does not include SMUD's proposed 400 megawatt Iowa Hill pumped storage project in the Sierras.

27 The CAISO load accounts for nearly all of the state's electricity, but a few public utilities, LADWP, SMUD and IID operate outside of CAISO and add several thousand megawatts to the state peak load. On the hottest day in 2006, LADWP peaked at 5388 mw (http://www.ladwpnews.com/go/doc/1475/169933/); SMUD's peak is about 3000 mw (http://www.smud.org/en/board/Pages/compact-customer.aspx); and IID's peak is over 800 mw.

28 The OTC Reliability Study cited correctly an expected long term growth rate in demand of 1.1 to 1.2 percent "for the foreseeable future" (p. 19), but did not point out that the cited peak demand in 2006 was an extraordinarily high anomaly, not a baseline for future expected growth.

29 Map source: California Energy Commission, http://www.energy.ca.gov/maps/transmission_lines.html

30 US Transmission Capacity: Present Status and Future Prospects, by Eric Hirst, prepared for Edison Electric Institute and Office of Electric Transmission and Distribution, US Dept. of Energy, August 2004, p.34.

31 BUGS 1 – Database of Public Back-Up Generators (BUGS) in California, Updated January 2004. California Energy Commission, http://www.energy.ca.gov/database/EDITED_PUBLIC_BUGS_INVENTORY.XLS

32 The State of Demand Response in California, A. Faruqui, R. Hledik, Publication Number CEC-200-2007-003-F, California Energy Commission Division of Electricity and Demand Analysis, September 2007. Table 6, p. 16.

33 On July 24, 2006 CAISO peak load reached 50,270 megawatts, with total California load at about 60,000 megawatts. Total resources available to the state are nearly 30,000 megawatts above the highest peak.

34 July 2006 CAISO Actual System Daily Peak Demand, Generation and Imports at Time of Daily Peak, CAL_ISO_08_29_2006.

35 California Energy Commission (CEC), "Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements." 2004. pp. 9-13. Plants in CEC's group not in ours: Humboldt Bay has been repowered since the CEC report; Hunter's Point has closed; Coolwater Units 3 and 4 were repowered; Long Beach is closed pending repowering; Grayson is a small facility using landfill gas and no OTC.

36 Local Power study on South Bay Power Plant is available at www.environmentalhealth.org

37 CEC, "Comparative Costs of California Central Station Electricity Generation Technologies." 2007, p. 34; also GE

38 IFC Jones & Stokes, Global Energy Decisions, and Matt Trask. "Electric Grid Reliability Impacts from Regulation of Once Through Cooling in California." Prepared for California Ocean Protection Council and State Water Resources Control Board. April 2008.

39 http://www.caiso.com/18c6/18c6b8955af80.pdf

40 California Energy Commission (CEC), "Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements." 2004. Page 35.

41 EIA

42 Units 3&4 were not included in the CEC, but were estimated to have the same AFRR as Units 1&2 since they have the same capacity.

43 CEC "Resources, Reliability ..." 2004, page 33

44 EIA Natural Gas Monthly Table 22, http://www.eia.doe.gov/natural_gas/data_publications/natural_gas_monthly /ngm.html; a thousand cubic feet (tcf) is very close to one million btu (mmbtu).

45 EPA. "Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions – Volume 2: Health and Welfare Benefits." 1998. http://yosemite.epa.gov/ee/epa/ria.nsf/vwRef/A.98.4++B?OpenDocument

46 Yohe, G.W. et. al. *Climate Change 2007: Impacts, Adaptation and Vulnerability. Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. M.L. Parry et. al. Eds., Cambridge University Press, Cambridge, UK. 2007. Chapter 20, Pages 811-841.

47 IPCC, WGII, Fourth Assessment Report, Summary for Policymakers, p.17.

48 ibid.

49 Letter of 19th March, 2008, from Joan Ruddock, MP, Parliamentary Under Secretary – Climate Change, Biodiversity and Waste, UK. to Andrew Tyie, MP, House of Commons.

50 Climate Change Proposed Scoping Plan, October 2008, California Air Resources Board.

51 State Water Resources Control Board, CalEPA. "Proposed Statewide Policy on Clean Water Act Section 316(b) Regulations." June 2006. Page 6-7. El Segundo currently uses OTC, but plans to switch to dry cooling by 2010, and is not included in this figure.

52 This includes mortality from both nuclear and natural gas OTC plants. California Coastkeeper Alliance website: http://www.cacoastkeeper.org/programs/healthy-marine-habitats/OTC

53 CEC. "Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants." Staff Report #CEC-700-2005-013. June 2005. Page 15-18.

54 Costanza, Robert et al. "The Value of the World's Ecosystem Services and Natural Capital." *Nature,* Vol 387, May 15, 1997.

55 CEC. "Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants." Pages 59-61.

56 Current natural gas price at NYMEX is $3.51 on April 21, 2009. This, however, excludes a several costs that are added between the origin point at Henry Hub in Louisiana and delivery to the power plant. Charges include: delivery to California border, distribution by the California gas utility, franchise fee, and hedging transaction cost. This has been estimated by the CPUC natural gas model for the MPR to range from 90 cents to about $1.20 over the next 20 years. See Appendix 2 for CPUC model projections.

57 These figures are approximations that characterize the range, but must necessarily be incomplete due to the fact that private owners of most of these plants keep some of the key cost data confidential.

58 Local Power investigated replacement options for one aging plant with OTC in its report to the Environmental Health Coalition, Green Energy Options to Replace the South Bay Power Plant, by P. Fenn and R. Freehling, Feb. 15, 2007.

59 http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_1551-1600/ab_1576_bill_20050929_chaptered.html

60 CEC "Comparative Costs of California Central Station Electricity Generation Technologies." 2007.

61 Ibid, pg 40

62 CEC 2007 pg. 41

63 In the table one must multiply the given value by 1000 to get the market heat rate.

64 This leaves out of consideration NOx from Humboldt, which is not in the study group, and Coolwater, which has a significant NOx problem.

65 An example was the proposal to replace the South Bay Power Plant in Chula Vista. In that case LS Power tried to push for construction of a baseload plant which would likely have operated at least twice as much as the current plant. It turned out, however, that SDG&E—the local utility—did not need any additional baseload capacity at the time LS Power intended to bring the plant on-line around 2010.

66 Climate Change Proposed Scoping Plan, *a framework for change, October 2008, p. ES1.*

67 Ibid., p.118.

68 "Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants." CEC, Page 43.

69 *Calpine to Spend More to Improve Plant Performance, Fusco Says*, By Jim Polson, Bloomberg.com, Sept. 5, 2008. Article states that Calpine's operating expenses for its mostly natural gas power plants increased $59 million in the first half of 2008, up 15% from a year earlier. The fleet of plants is on average less than 10 years old, and the new high efficiency technology is having more problems than expected.

70 Comparative Cost of California Central Station Electricity Generation Technologies, Dec. 2007, reported a cost of 59.96 cents per kilowatt-hour for electricity from new simple cycle natural gas plants.

71 The amount of pumped storage in California is likely to increase in the next decade to at least 4500 megawatts if SMUD brings its Iowa Hill unit on-line as planned.

72 See appendix 8 for table from CEC report on aging plants.

73 $800 million per year is spent by the CPUC for the Investor Owned Utilities, with additional funds set aside for this purpose by the Publicly Owned Utilities.

74 Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California, *Prepared for:* California Ocean Protection Council *and* State Water Resources Control Board, *Prepared by:* ICF Jones & Stokes, Global Energy Decisions *and* Matt Trask, April 2008.

75 Ibid, p.

76 California's Renewable Energy Goals—Assessing the Need for Additional Transmission Facilities, March 2009. RETI consultant report.

77 Powers, Bill. "CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost Effective." Natural Gas & Electricity, August 2009.

78 Comparative Cost of California Central Station Electricity Generation Technologies, Dec. 2007. p. 7.

79 Renewable Energy Transmission Initiative Phase 2 report. March 4, 2009, Page 189. http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF

80 Local Power, "Green Energy Options to Replace the South Bay Power Plant." Feb 2007.

81 Comparative Cost of California Central Station Electricity Generation Technologies, Dec. 2007. See Appendix 8 for full table of cost of electricity from different power sources in the Energy Commission report.

82 RETI Phase 1B Report, January 2009, Appendix D. Samples from the RETI table of projects can be seen in Appendix 9 of this report.

83 See table of generation costs in Appendix 7; this assumes that the new natural gas plant operates at 5% capacity factor, equivalent to 435 hours per year, while the demand response resource will certainly be called upon to a much lower degree.

84 2002–2012 Electricity Outlook Report, California Energy Commission, February 2002. P-700-01-004F. p. 86. The chart value labels on the left show costs in the thousands of dollars, which would appear to be a typographical error. The correct values would range from $0 to $10 per kilowatt-hour, with the comma indicating where the decimal point should be.

85 2002–2012 Electricity Outlook Report, California Energy Commission, February 2002. p. 92.

86 Green Plants or Power Plants, 'Center for Urban Forest Research, USDA Forest Service, Davis, CA.

87 "Assuming a weighted-average EUL of 8-12 years, and 5% real discount rate, the forecasted program costs in the full incremental cost scenario are equivalent to a levelized cost of roughly $0.04-0.06/kWh." CPUC Energy Efficiency Staff Paper on Recommended 2012-2020 Energy Efficiency Goals, p. 8.

88 CEC. "Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements." Page 104.

89 Woods Hole Research Center. An Inventory of California Coastal Economic Sectors, January 2003. http://www.whoi.edu/mpcweb/research/NOPP/California%20region%20progress%20report%20Jan03.pdf

90 California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios, Consultant Report, California Energy Commission, November 2003, 500-03-106.

91 Decision adopting interim energy efficiency savings goals for 2012 through 2020, and defining energy efficiency savings goals for 2009 through 2011, California Public Utilities Commission, Decision 08-07-047 July 31, 2008.

92 Comparative Cost of California Central Station Electricity Generation Technologies, Final Staff Report, California Energy Commission, CEC-200-2007-011-SF, Dec. 2007; p. 12. While there is broad agreement with the results and methodology of the Energy Commission, this current report of Pacific Environment and Local Power, along with the RETI Phase 1B report of January 2009 both found much lower costs for mid-scale (1 to 20 mw) photovoltaic technology in the approximate range 22 to 30 cents per kwh. Somewhat higher cost of energy could occur if projects are developed in areas of the state with low solar resource, or for photovoltaic systems with poor performance due to excessive shading or other problems.

93 California Energy Commission (CEC), "Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements." 2004. p.61.

About the Authors

Robert Freehling is currently Research Director for Local Power, an energy consulting business that advises local communities about how to develop renewable energy and increase local control over energy policy. Local Power created and promotes the concept of Community Choice Aggregation, a creative market structure—operative in California, Ohio and Massachusetts—that allows local governments to purchase electric power for all the customers in their jurisdiction. Local Power has worked with San Francisco to develop a Community Choice program to convert up to 51% of the City's electric power to renewable energy by 2017. Mr. Freehling's role is to research and provide technical analysis of markets, technologies, and public policies that increase reliance on sustainable local energy supplies and reduce greenhouse emissions. Mr. Freehling is also a member of Sierra Club California's state Energy and Climate Committee, performing analysis and providing advice on legislation, policy, and proposed energy projects.

Suzanne Doering received a BS Mathematics/BA History from Indiana University and her MS in Mathematics from the University of Chicago. While at Chicago, Ms. Doering found that environmental economics coursework combined her interests in quantitative analysis and environmental issues, particularly climate change. She interned for Pacific Environment in the summer of 2007, contributing research and analysis to this report. Currently, Ms. Doering teaches math at Lincoln Park High School in Chicago, preparing and inspiring her students to face the next generation's environmental challenges.

Rory Cox is California Program Director at Pacific Environment, where he has served on staff since 1998. Mr. Cox founded the California Program, which has taken the position that the best solution to the West Coast's dependence on fossil fuels is conservation and the development of emission-free renewable energy. Mr. Cox also founded the RACE Coalition, which represents 30 community organizations from Mexico to Canada. He has a track record of bringing different interests together to refuse hazardous and polluting fossil fuel projects and embrace clean energy alternatives. He has worked with environmental justice, community, and conservation groups and clean energy businesses to gain significant wins along the West Coast, including blocking construction of six LNG import terminals. He holds a bachelor's degree in public communications from California State University-Chico and a master's degree in international relations from San Francisco State University.

PACIFIC ENVIRONMENT protects the living environment of the Pacific Rim by promoting grassroots activism, strengthening communities, and reforming international policies.

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