Issue Paper

RAND Enterprise Analysis/Environment

Load-Centered Power Generation in Burbank, Glendale, and Pasadena:
Potential Benefits for the Cities and for California

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For the first two years after California deregulated the state's electricity sector, the restructured system seemed to work as intended—consumers and businesses paid less for electricity in the new competitive marketplace. But in the summer of 2000, the prices on the spot market for electricity spiked, the cost of power increased tenfold, and the first power shortages appeared, culminating in rolling blackouts during the following winter.

More than 30 days of rolling blackouts were predicted statewide for the summer of 2001, with shortages during peak times estimated at 5,000 megawatts—or about 8 percent of demand. There is the potential for continued price spikes and shortages through the winter of 2002 and possibly through 2004 if demand remains strong and current capacity expectations do not materialize.

About one-quarter of all demand for electricity in California is met by publicly owned utility companies that were not subject to the 1998 deregulation. Three of these—the municipal utilities in the cities of Burbank, Glendale, and Pasadena—are pursuing a broad-based portfolio of energy generating resources to protect them from the problems that plague the system as a whole. They are looking hopefully at a generating strategy called "load-centered generation" (LCG) that would make the cities less vulnerable to upheaval on the electricity markets and allow them to not only meet their own needs but also sell power out of their service territory, thus adding capacity to the state system.

LCG is the generation of power near the centers of demand, or "load," and represents the middle ground between conventional central station generators and the emerging paradigm of distributed generation. The LCG strategy calls for the utilities to install new, natural-gas-fired generators on the sites where they now have steam and combustion turbines. The three cities are hoping to receive incentives from the state to help them fund the new plants and bring them online quickly.

RAND helped the utilities examine the value of the new plants within the context of California's continuing energy problems, reviewed and summarized the literature related to LCG, and constructed statistical models of the electricity market and of the potential cost savings the new plants might provide.

The benefits of LCG can be considerable. Because LCG power is generated close to the load and transmitted along low-voltage distribution lines, it can reduce the strain on California's already overstressed transmission grid and improve reliability. Local customers would be less vulnerable to natural disasters, power losses along the grid (approximately 1 percent per 100 kilometers), and transmission line failures such as the January 21, 2001, substation failure in Oregon that caused 20 minutes of rolling blackouts in Northern California. We did not attempt to quantify these benefits in this report, but the literature values reliability at $60 to $60,000 per megawatt-hour (MWh) and savings due to deferrals of transmission line investments at $10 to $70 per MWh.

LCG would also reduce California's vulnerability to power recalls by out-of-state generators. With nearby states growing even faster than California, out-of-state generators that have traditionally provided power to California may be selling that power in their own states. In some states, such as Utah, even power already contracted to California is subject to recall in times of need.

In addition, generators owned by residents keep capital and investment within the state and provide revenue through taxes and employment. In discussing the electricity markets and prices in California, the Federal Energy Regulatory Commission (FERC) has declared that the electricity markets have been dysfunctional; yet until recently the FERC has chosen to take no regulatory action to improve the way the market functions. Increasing the amount of in-state electricity and selling it at cost-based rates can help counter limited federal actions by increasing supply, improving competition, and moderating prices in California markets.

The proposed plants are considerably cleaner than the turbines now on the sites, potentially reducing the amount the utilities pay for emissions credits and, at least theoretically, increasing the chances that the new plants will be acceptable to an environmentally sensitive public.

The most persuasive argument in favor of the new plants came to light with the mathematical models that were constructed to determine the impact the new generators would have on California's wholesale power prices. Under a reasonable set of assumptions for the future, the new plants could provide savings for California between $466.7 million and $584.9 million over the period 2002 to 2011. Running duct burners[1] on the base load plants during the winter and summer increases the total value of the generation by about 10 percent, but decreases the savings per MWh of new generation.

In developing the models, RAND considered several variables and made several assumptions. It was assumed that in the near future only a small amount of power will be bought on the spot market and that the pricing for electricity will be based on generation costs, which are based on natural gas and emissions prices plus the capital costs and operating and maintenance costs for the plants.

We modeled the cost of two types of new generation in California—the first from the plants in Burbank, Glendale, and Pasadena, and the second from other, mostly private, natural-gas-fired plants projected by the California Energy Commission (CEC) to come online in the near future. For the latter group of plants, we made adjustments for differentials in capital costs and for transmission losses that would occur if the new plants are located far from their load. To capture these losses, we increased the price to reflect the additional generation required to meet demand.

To ensure that we captured the most likely future scenario for the value of the new generation, we ran models for a variety of natural gas prices, emissions credits prices, and rates of growth in demand. We also considered whether the utilities would run duct burners during the summer and winter, which would increase the output of the plants but also reduce efficiency and increase emissions.

Although not all the benefits associated with load-centered generation are quantified in this report, the literature gives some understanding of the magnitude of benefits it offers and suggests that it will become an increasingly important part of California's energy portfolio. To encourage the development of LCG, California can do the following:

- Streamline the approvals process to bring new generation online more rapidly
- Provide financial incentives such as low-interest loans, state-backed bonds, and long-term state contracts or investments
- Provide greater flexibility on emissions credits
- Guarantee the purchase of excess capacity.

CALIFORNIA'S ENERGY ISSUES

The potential value of the new generation that would be supplied by the new plants in Burbank, Glendale, and Pasadena must be considered within the context of the ongoing energy problems in California and the western region of the United States.

In 1998, the California electricity system was restructured with the intent of making the electricity markets competitive. As privately owned utilities began to face competition in the generation of electricity, they were encouraged to sell their generation assets, and most of them did. For the first two years, the restructured system seemed to work as intended. But predictions for the summer of 2001 foresee at least 30 days—or as many as 60 days—of rolling blackouts. California and the rest of the

[1] A duct burner reburns exhaust coming from the turbine and uses the additional heat to produce more energy.

western region are also likely to see significant price spikes and continuing base price increases that may continue into next summer, too.

The inability of California's electricity system to satisfy demand is indicated by the increased number of alerts, warnings, and emergencies issued by California's Independent System Operator (ISO). Figure 1 shows how the problem has manifested itself since the beginning of electricity deregulation in 1998. Each bar in the figure represents a one-month period during the season and year indicated. An emergency is categorized into one of three stages depending on the amount of reserve generation that is available to the state system. As the system enters a Stage 3 emergency, plans are made for rolling blackouts, and they are instituted as demand exceeds available generation.

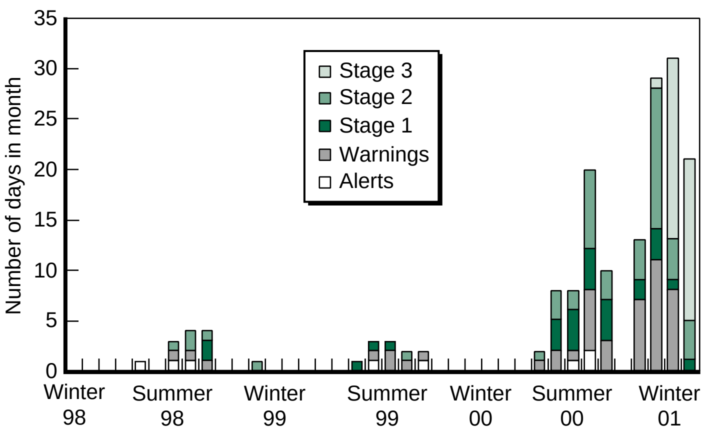


Figure 1—California ISO Alerts, Warnings, and Emergencies

The supply of electricity is tight in California because demand has grown without a commensurate increase in supply. Lack of rainfall in the Pacific Northwest has reduced the amount of hydroelectric power that is available for California to import. Old plants in need of replacement are not operating at full capacity. Uncoordinated and unregulated scheduling of repairs and maintenance has also reduced supply.

Prior to deregulation, maintenance was planned to protect the reliability of the system and was scheduled for times when demand was low. In the restructured system, private generators can schedule maintenance, and shut down generators in order to accommodate it, on their own schedules. In addition, some utilities are not being paid and cannot keep generating. Finally, growth in capacity has not kept up with demand. Figure 2 compares the growth rates of generating capacity and electricity demand. Whereas California is not short on available capacity, the reserve margin is considerably smaller than it has been historically. The growth in demand that California has experienced over the past five years cannot be sustained without new capacity coming online soon.

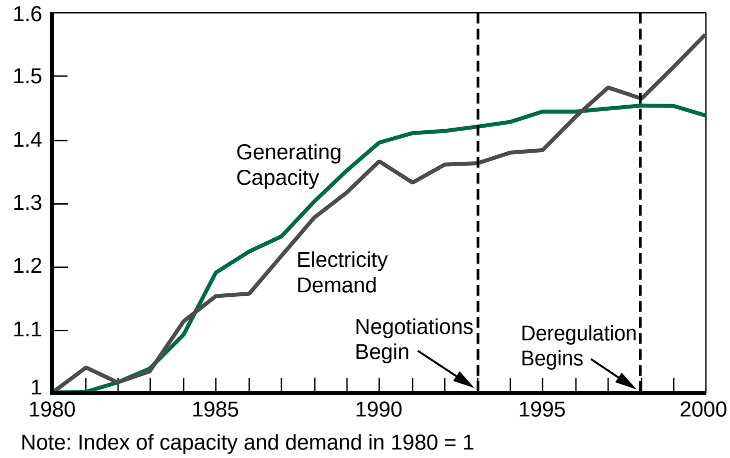


***Figure 2—Indexed Supply and Demand in California*[2]**
(Source: CEC)

Not only is the state in need of additional new capacity, much of the existing capacity is in need of replacement. More than 40 percent of the capacity in California is more than 40 years old (and 13 percent is more than 50 years old). These plants are no longer capable of producing power at full capacity 24 hours a day, and they are significantly less efficient and pollute more than new plants.

Conditions of tight supply are not limited to California. Population and commensurate energy demand have grown even faster in other western states than they have in California, and demand in those states has also outpaced capacity. For example, the population of Nevada has grown by more than 50 percent in the past ten years without commensurate growth in generating capacity.

Supply constraints have led to price increases and spikes that never occurred before in these markets. In the first two years of deregulation, maximum prices in the wholesale markets averaged less than $10 per MWh, with occasional spikes as high as $200 per MWh. In the summer of 2000, however, prices reached almost $1,000 per MWh and averaged a high of almost $200 per MWh throughout the summer. The following winter, when demand is typically at its lowest in California, prices spiked even higher to more than $1,500. Figure 3 shows recent price trends of electricity purchased in California.

Natural gas shortages and the accompanying price spikes are also part of the energy crisis in California and the other western states. At the same time that electricity prices were fluctuating and spiking, so were natural gas prices (see Figure 4). In fact, the increase in natural gas

[2] The value for each year shown in Figure 2 represents the ratio of the supply (or demand) for that year compared with the supply (or demand) in 1980. The intersection of the two curves around 1996 does not imply that demand exceeded supply from that point onward.

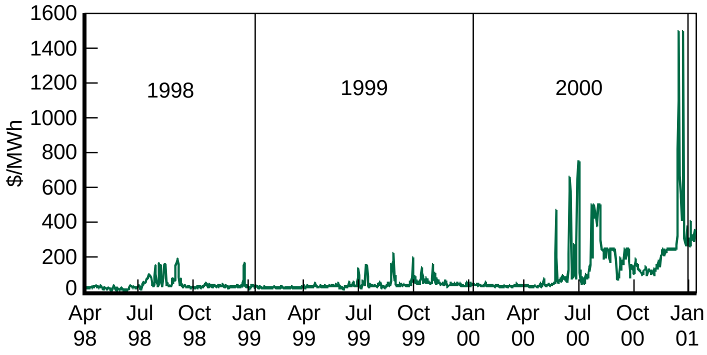


Figure 3—Maximum Daily Electricity Prices on the California Power Exchange

prices that was seen in the winter of 2000 contributed to the increase in electricity prices. It is also possible that rising electricity prices allowed natural gas prices to rise further. While prices in the natural gas markets have recently stabilized at approximately $9 per million British thermal units (MMBtu), these prices are four to five times higher than they were throughout the 1980s and 1990s. It is likely that the natural gas markets, which have been deregulated for 30 years, will stabilize more quickly than electricity markets. Most forecasts have prices stabilizing at about $5 to $6 per MMBtu, still about double their historic levels.

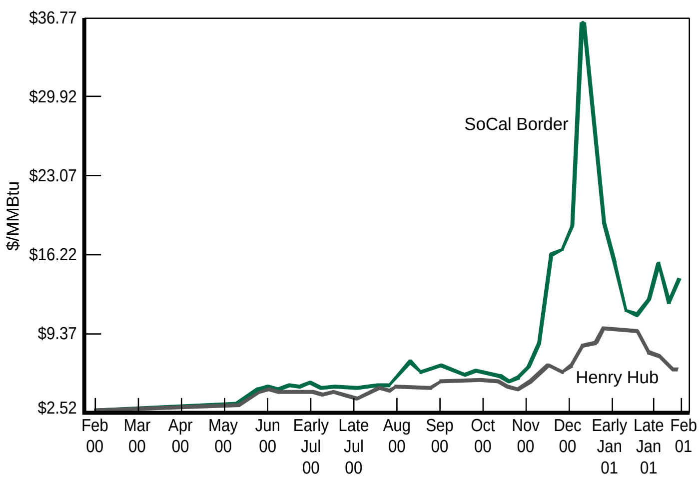


Figure 4—Weekly Spot Market Prices for Natural Gas at Southern California Border and Henry Hub, Louisiana (Source:* Natural Gas Weekly*)

If current projections of supply and demand turn out to be true, electricity and natural gas shortages in California and the rest of the West are likely through the winter of 2002 and possibly through 2004. The total peak demand for California in the summer of 2001 is expected to be around 60,000 megawatts (MW), and some estimates expect a shortage of as much as 5,000 MW during peak times. There are likely to be price spikes during this period as well.

While new generating capacity is planned and under construction in California, there may not be enough electricity to meet the state's needs in the summer of 2001. The CEC estimates that between 7,000 and 12,000 MW of new generation might be available by 2003 (see Figure 5). If this generation becomes available by 2003, many, but not all, of the current supply problems may be alleviated.

In an effort to be conservative, we use the higher CEC estimate of about 12,000 MW of new generation online by 2003 in our analysis, but it is more likely that this amount will not be built until after 2003. As illustrated in Figure 5, "Rapid" and "Cautious" are two growth rate scenarios that the CEC proposed. For the cautious scenario, the same amount of generation comes online as in the rapid scenario, but much of it comes online at a later date.

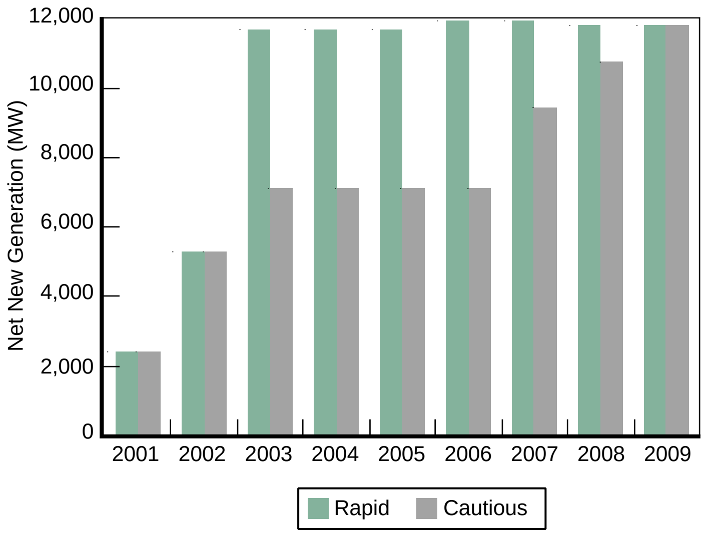


Figure 5—Estimates of New Electricity Generation in California (Source: CEC)

Furthermore, much of the new generation is located in Northern California, which means that transmission capacity will be a critical factor in determining how much of this new generation can alleviate power problems throughout the state. Rolling blackouts in Northern California in the winter of 2000 to 2001 were partially due to the fact that the transmission line between Southern and Northern California (Path 15) was at capacity. It is important to note that new generation is not evenly distributed throughout the state, and that without addressing the current transmission bottleneck between Northern and Southern California, more generation located in Southern California may be necessary to meet local demands. This suggests that there may be a value to siting new generation in Southern California.

MODELING THE POTENTIAL VALUE OF NEW GENERATION

To determine the impact of this new municipal generation on wholesale power prices, we developed a model that simulates the potential operation of the electricity market in 2002 and beyond. The essential elements of the model are described in this report; more details are available on request.[3]

Generation in Burbank, Glendale, and Pasadena

Currently, Burbank, Glendale, and Pasadena have approximately 500 MW of local generating capacity. However, due to fuel and / or emissions constraints, much of it runs only part time and provides energy only during peak periods or in emergencies. The cities fulfill most of their electricity needs through partial ownership of other generating facilities and long-term contracts with remote generators.

The proposed new generation will come from four base load plants (GE 7FA) to run nearly full time and eight smaller peaking units (LM6000 Sprint) to run during peak periods (primarily during the winter and summer). The peaking units are highly efficient, simple-cycle gas turbines with a capacity of about 50 MW each. The base load units are larger, combined-cycle gas turbines with a capacity of about 250 MW each. These units will also be equipped with duct burners that can increase the capacity of each unit to about 300 MW, but in so doing decrease the fuel efficiency and increase emissions.

Seasonal data on the energy output, costs, fuel use, and emissions of each base load plant and each peaking plant by location were provided by Bibb and Associates. Much of the generation currently located in Burbank, Glendale, and Pasadena is 25 to 50 years old, has poor fuel efficiency, and pollutes more than most modern generation. The nitrous oxide (NOx) emissions of the proposed generation are considerably lower than almost all of the current generation located in the municipalities. The peaking plants are expected to come online in June 2002, and the base load plants in June 2004. Table 1 summarizes the characteristics of the existing and proposed power plants in the three cities.

Metrics, Levers, Uncertainties, and Assumptions of the Model

A number of outcome measures, levers or decision points, uncertainties, and critical assumptions were essential variables in our modeling approach:

Metrics

- Total value of reduced cost to the grid
- Value per MWh

Levers

- Build generation or not
- Run duct burners or not

Uncertainties

- Natural gas prices
- NOx credit prices
- Demand
- Supply curves

Assumptions

- Interest rates and capital costs
- Electricity market operation
- Cost of non-municipal generation
- Transmission losses
- Amounts of “must-run” generation
- Operation of the qualifying facilities

Metrics define the measurable outcome of the modeling effort, defined here as the value of the new municipal generation in terms of the total cost savings over the next ten years (2002 through 2011), when the new generation is included in the electricity market versus when it is not. This value is given both in total dollars saved as well as dollars saved per MWh of new generation.

Levers describe choices or decisions to be made. In this analysis, there are two decisions: whether or not to build the new generation and whether or not to run duct burners on the new base load generators. The analysis compares the modeling results with and without the new municipal generation, and with and without the use of duct burners.

City	Current Local Generation (Total Capacity)	Proposed Local Generation (Total Capacity)
Glendale	Two combined cycle plants Three steam units Two gas turbines (250 MW total)	One GE 7FA unit Five LM6000 Sprint units (500 MW total)
Burbank	Two steam units Three combustion turbines (161 MW total)	Two GE 7FA units (500 MW total)
Pasadena	Three steam units Two combustion turbines (183 MW total)	One GE 7FA unit Three LM6000 Sprint units (400 MW total)

Table 1—Current and Proposed Municipal Generation

[3] For further information about the model, contact Paul Dreyer at dreyer@rand.org.

It was necessary to make a set of assumptions in the analysis. We assumed that the capital costs of the plants will be handled by a low-interest (5 percent) loan over 20 years, that a payment for the loan is made each hour the plants are running (every hour of the year for the base load plants, and every hour during the summer and winter for the peaking plants), and that operating and maintenance costs are evenly distributed throughout the year. All excess capacity not used by the municipalities will be made available to the state.[4]

Another major assumption, as well as a major uncertainty, is how the electricity market will operate. We assume that after actions by the state government the electricity market will stabilize in the post-2002 time frame. The goal of current policies is to return costs to what they were in the first two years of the restructured market (1998 and 1999). Policy makers assume that during that time market bid prices approximated the cost of production (Borenstein, Bushnell, and Wolak, 2000). As a starting reference point, we assume that each generator would be paid its marginal cost.[5] Scenarios that modify this reference point are discussed later in this report, as are other assumptions made for modeling purposes.

Among the major uncertainties are future natural gas prices, which are the most significant portion of the generation costs. To reflect this uncertainty, we use four natural gas price scenarios with prices ranging from $2.50 per MMBtu to $10 per MMBtu. Current prices at the Southern California border are about $12 per MMBtu, although most forecasts stabilize natural gas prices at about $5 to $6 per MMBtu.

Another important uncertainty in the model is the anticipated growth in demand. The California ISO, responsible for maintaining the transmission grid in the state, maintains an archive of the total demand on the grid for each hour.[6] Given the hourly demand from 1999, we add an additional annual demand growth factor, which we vary from 1 to 4 percent per year.

Beginning with the marginal costs of generation, we build a supply curve of power costs. There is debate over whether these marginal costs of supplying power will be the basis for costs, and some of the literature describes analyses of the California market that have led to different conclusions. To capture that uncertainty, we run a number of scenarios that vary this supply curve and represent different options for how the market may operate in the future.

[4] The municipalities intend to charge the state their generation costs plus a reasonable rate of return. Information on how the municipal utilities provide service was provided by the utilities themselves.

[5] Many thanks to James Bushnell at the University of California Energy Institute for providing this data.

[6] See http://www.caiso.com/marketops/OASIS/pubmkt2.html

Finally, uncertainty in emissions costs is included in the model, as emissions costs do have significant impact on generation prices. The analysis encompasses the impact of a broad range of NOx prices ranging from $5 to $50 per pound. We assume that the municipalities would purchase all of the NOx emissions credits needed to run their plants. This is an overestimation, as each plant receives an initial allotment of NOx credits. PM10 (particulate matter of size 10 microns or less) costs are also included in the model, but because PM10 impacts costs less than NOx does, the PM10 costs are included as a fixed estimate.

Using the data provided by Bibb and Associates, we computed generation costs for each plant during each season for a variety of natural gas and NOx costs. Sample prices for the proposed new municipal generation are given in Figure 6. This figure shows how the generation costs in dollars per MWh vary with changes in assumptions about natural gas and NOx credits prices. Each band in the figure represents a range of market prices. For example, for the GE 7FA units using duct burners, if gas costs $5 per MMBtu and NOx credits are $20 per pound, the cost of generating power would be in the range of $50 to $75 per MWh.

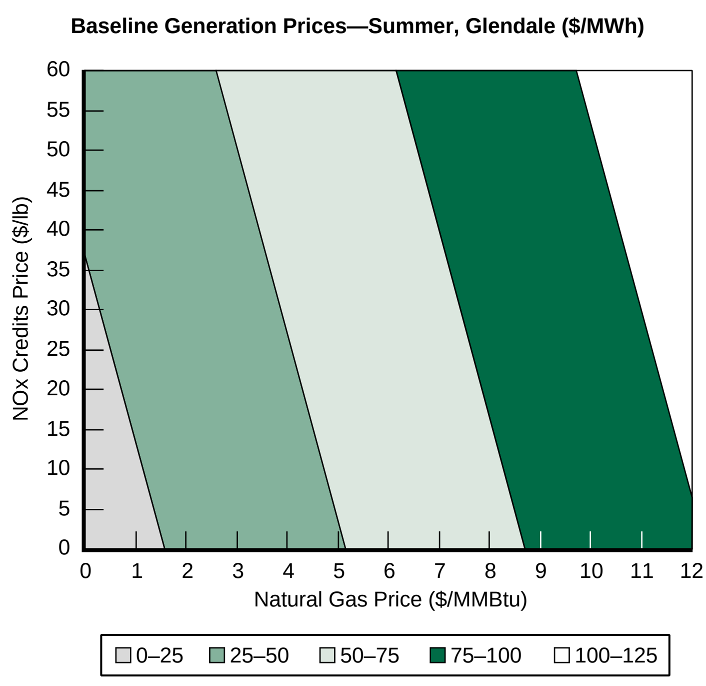
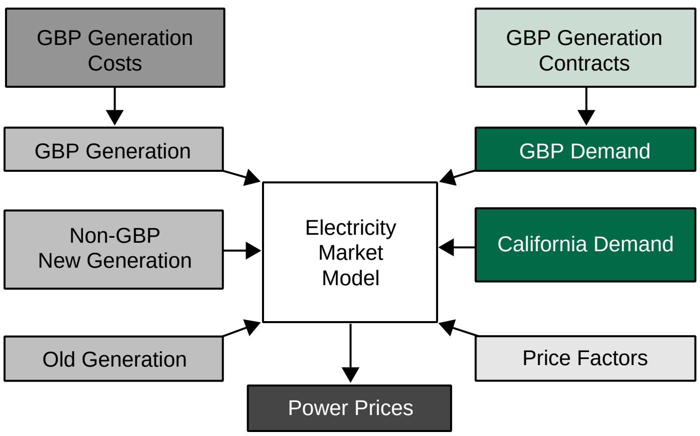


Figure 6—Sample Market Prices for the Proposed Municipal Generation

Modeling the Operation of the Electricity Market

With the recent shutdown of the California Power Exchange (PX), a central market no longer exists for the short-term buying and selling of power in California. Despite the current instabilities and scarcity in generation, we believe that in the near future there will be cost-plus pricing for electricity purchases in California. Using data from the University of California Energy Institute, the PX, and the California ISO, we developed a model to predict power prices in this new electricity market.

To model the electricity market, we built a supply curve based on generation costs and simulated the dispatching of power plants based on these costs. We assume that the generators who bid into the market previously will continue to make their capacity available to the electricity market in the near future, with modifications to their costs based on natural gas prices, emissions costs, and inflation. A schematic of the model is shown in Figure 7.



Note: BGP = Burbank, Glendale, Pasadena

Figure 7—Schematic of the Power Pricing Model

We also include in this model two types of new generation: the generation from Burbank, Glendale, and Pasadena, and the generation from other plants coming online in California in the near future, as projected by the CEC. The cost of the three cities' new generation is based on capital, operating, fuel, and emissions costs. As most of the new generation reported by the CEC is natural gas-powered, we modeled its price using a similar method, but modified it to include a differential in the cost of capital and the time to repay loans.[7] Because one of the advantages of load-centered generation is that transmission losses are reduced, the model gives a benefit to LCG to reflect the fact that a higher proportion of electricity from these load-centered plants, as opposed to distant plants, will be available to end users.

A portion of the demand estimated for the future will be satisfied by "must-take" generation (electricity the state is required to take, for example nuclear, long-term contracted, and some hydroelectric power) in addition to geothermal and other hydroelectric generation. To estimate the amount of capacity of these types of generation available each hour, we used the amount of "price-taker" supply bids from the day-ahead market of the California PX.[8] "Price-taking" generators bid into the PX at a price of zero, meaning that they would dispatch their energy at any price.

These price-taker bids included the nuclear facilities owned by IOUs (investor-owned utilities, such as Pacific Gas and Electric and Southern California Edison) in addition to much of the available geothermal and hydroelectric generation. We assume that another portion of the demand (about 12,000 MW) will be fulfilled through contracts with "qualifying facilities"—small generators that qualified under an earlier federal rule to operate independently of the electric utilities. The remaining demand for each hour is satisfied by fossil-fuel-fired power plants on the electricity market.

In our model, the least-expensive generation available in the market is dispatched until all demand is satisfied. If there is insufficient supply available in the market for that hour, the remaining supply is purchased on the spot market at $500 per MWh.

The Results of the Model

The model was run under multiple scenarios, and it generated a broad range of outcomes. For each set of variables, the model was run with and without the proposed new municipal generation. The variables included the following:

- Natural gas prices from $2.50 to $10 per MMBtu
- NOx prices from $5 to $50 per pound
- Demand growth from 1 to 4 percent per year
- Varying the supply prices plus and minus 10 percent and 20 percent
- Duct burners running or not running.

A plausible set of assumptions might have the price of natural gas in the near future ranging from $5 to $7.50 per MMBtu, the price of NOx credits to be about $20 to $35 per pound, and demand growth to be about 2 percent per year. Under this set of assumptions, the value of the new generation to the state of California would be between $466.7 million and $584.9 million over the ten-year period from 2002 through 2011. These dollar figures represent savings of about $5.30 to $6.64 per MWh of new generation. We include other fuel and emission prices and

[7] We assume that the municipal utilities will float 20-year bonds and that interest rates available to private investors are 3 percent higher than municipal rates and require a ten-year payback. These numbers are based on personal communications with GBH Investors.

[8] Before closing down, the PX maintained an archive of all supply and demand bids for each hour from its Day-Ahead market. For our model, we used the amounts of price-taker bids from each hour in 1999.

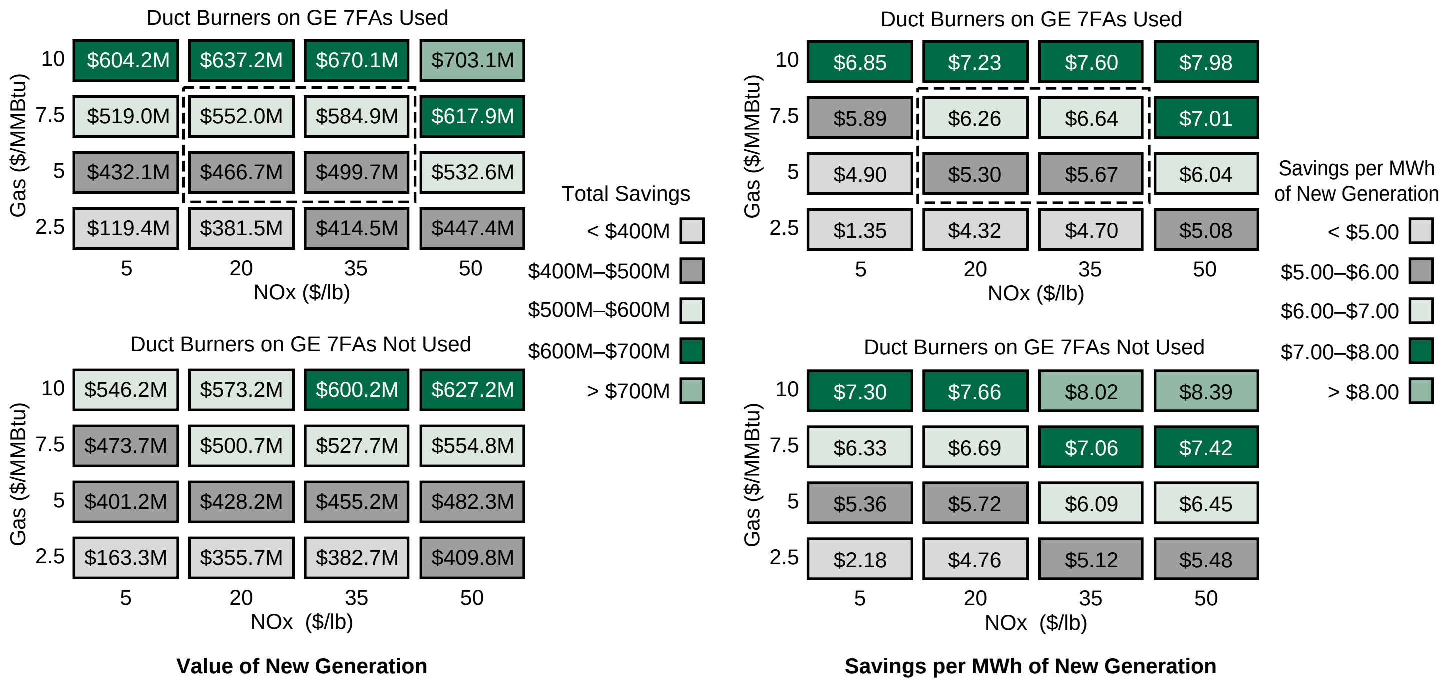


Figure 8—Comparing the Value of and Savings from the New Municipal Generation With and Without the Use of Duct Burners[9]

demand growth case rates to illustrate how changes in the quantities of fuel prices, emissions prices, and demand growth affect the value of the new municipal generation.

There are a considerable number of benefits unaccounted for in this analysis. The model does not factor in any benefits of LCG other than the cost savings derived from avoiding transmission losses. In addition, we used optimistic assumptions provided by the CEC about the projected supply of new, non-municipal power. If we had used less-optimistic projections of supply, the value of the generation provided by the new plants and the cost savings the new plants provide would be even higher.

As illustrated in Figure 8 above, the value of the new generation increases slightly if the duct burners on the GE 7FA units are used during the summer and winter, assuming a 2 percent growth in annual demand. However, the average savings per MWh of new generation are reduced when the duct burners are used. Although more supply is added to the market, the increases in heat rate and emissions add enough to the GE 7FA generation price to reduce the average savings of the generation to the state. (The most likely future price scenarios are surrounded by a dotted line in the figure.)

It might be the case that bids will not approximate the cost of generation; therefore, Figure 9 shows how the estimated value of the new municipal generation would change with changes in the supply curves caused by increasing and decreasing the supply prices (not including the new generation) by 10 percent and 20 percent. Except for two cases in which the supply prices are reduced by 20 percent (a somewhat unrealistic scenario because suppliers would rarely price their supply so far under their generation costs), these changes in the supply curve do not affect the value of the new generation by more than 5 percent.[10]

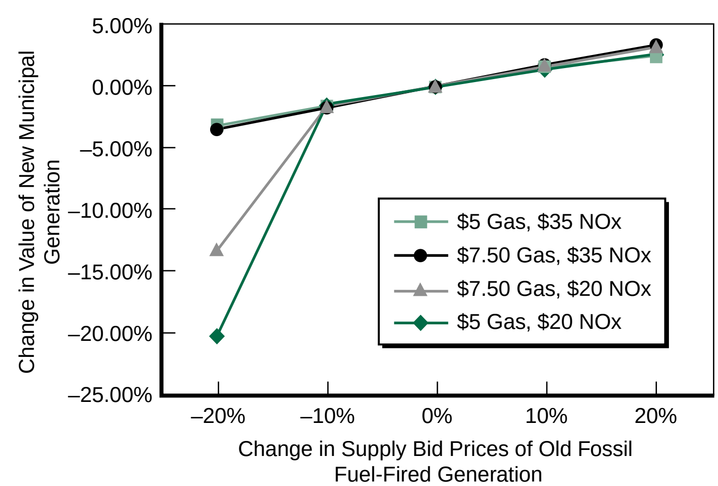


Figure 9—Comparing the Effects of Changing the Supply Price Curve on the Value of New Municipal Generation

9 Unless stated otherwise, for the following figures in this chapter we assume that the duct burners on the baseline plants are used during the summer and winter and that statewide annual demand growth is 2 percent.

10 For the two cases in which the value of the new municipal generation drops by more than 10 percent, the generation costs for much of the old generation are less than the price of the new generation, therefore the new generation gets dispatched far less frequently.

Figure 10 illustrates how statewide annual demand growth rates of 1 percent, 2 percent, and 4 percent would affect the value of the new municipal generation. (The best-estimate values are surrounded by a dotted line.) The difference between a 1 percent annual growth rate and 4 percent annual growth rate in the best-estimate value of the generation ranges from $311.8 million to $1.52 billion over the ten-year period.

Due to increases in annual demand and the fact that little new generation is planned to come online after 2003, the value of the new municipal generation increases considerably from year to year. Figure 11 shows the total savings accrued during each year from 2002 to 2011 for four different natural gas and NOx price scenarios.

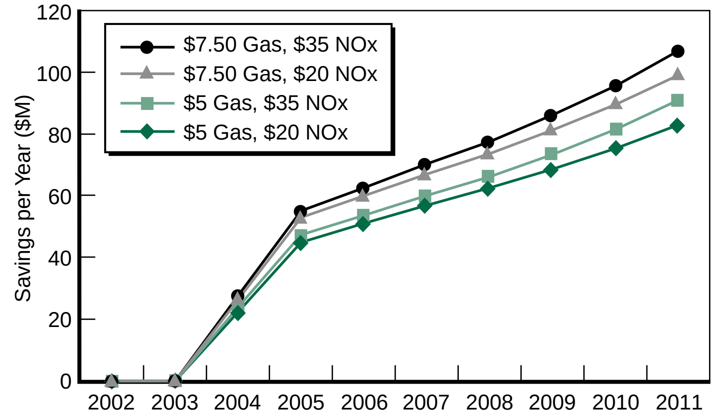


Figure 11—Annual Savings from New Municipal Generation, 2002 to 2011

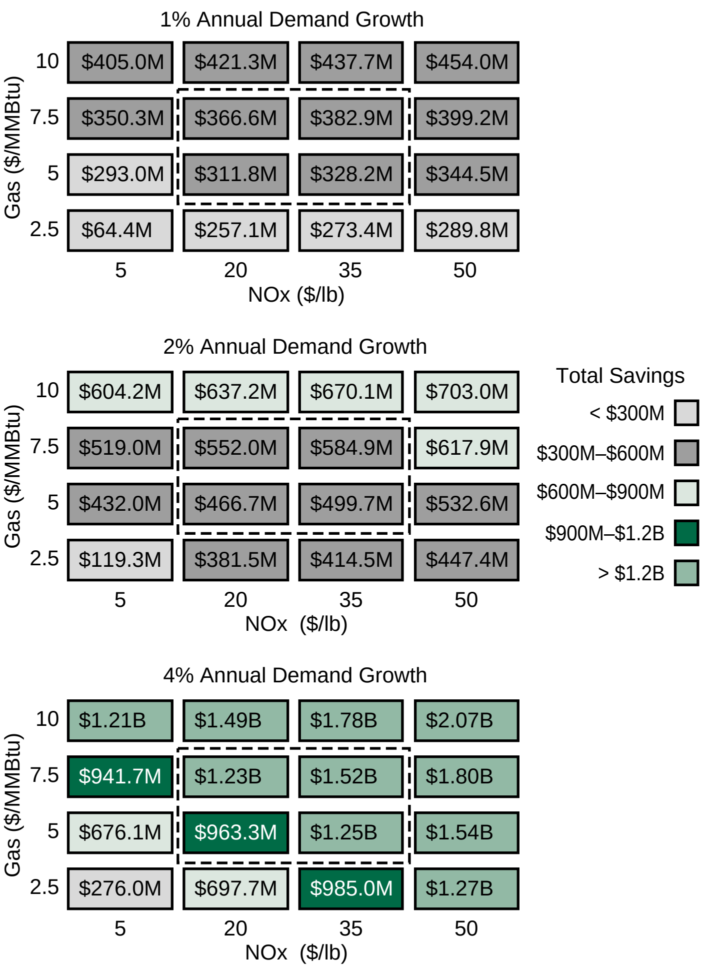


Figure 10—Comparing the Value of New Municipal Generation Given Different Rates of Growth of Statewide Annual Demand

LOAD-CENTERED GENERATION: A REVIEW OF THE LITERATURE

The literature about LCG describes several benefits that are not explicitly captured in our model, as many are site-specific and difficult to model. The literature also describes previous studies that estimated the cost savings the plants might provide; however, the quality of those studies is inconsistent. Accordingly, this section summarizes the content of the literature without endorsing the conclusions of the studies.

What Is LCG?

The current electricity supply market includes many large power plants that are sited in remote areas, far from the customers they serve. Such siting allows for lower land acquisition costs and easier compliance with environmental regulations than does siting plants in or near densely populated areas, but it can place a heavy burden on the transmission system. The concept of load-centered generation means building generating capacity close to the demand, or "load," in moderate-sized generating units.

While LCG is not precisely defined, it occupies the middle ground between conventional central station generation and the emerging paradigm of distributed generation (DG). Central station power plants are quite large, taking advantage of traditional economies of scale in electricity generation, and are designed to feed into the transmission grid at high voltages, principally supplying the electricity system rather than particular loads. In contrast, distributed generation employs recent advances in small-scale electricity generation to install generators[11] in the facilities of customers to supply their own base load, peak load, or standby power. As a third alternative to central station and distributed generation, LCG provides power to a larger region (or larger facilities) than DG, but shares much of its flexibility and reliability. Table 2 illustrates the roles played by the three generation schemes.

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[11] Most distributed generators in use are diesel-powered reciprocating engines, but a suite of advanced technologies are now or will soon be available, including natural gas–powered microturbines, solar photovoltaics, and fuel cells.

Generation Scheme	Typical Siting	Typical Unit Capacity	Typical Voltage
Central station	Rural area	> 400 MW	Transmission (> 115 kV)
Load-centered	City, large facility	20–400 MW	Sub-transmission (69–138 kV)
Distributed	Building substation	< 20 MW	Distribution (< 69 kV)

Table 2—Comparison of Electricity Generation Schemes

Benefits of LCG

As the demand for electricity continues to grow, many utility districts and larger regions are pressed to add capacity. The general benefits of adding capacity apply to adding capacity via LCG as well. Electricity markets are made more competitive (and larger reserve margins reduce the market power of independent power producers), reduced price volatility allows for better planning, and ancillary services are priced lower. Furthermore, LCG keeps power production in state, providing employment and tax benefits, as well as protection from the possibility that out-of-state generators will withhold power.

The most significant benefits from LCG relate to the reduced reliance and strain on the transmission grid. Much of California's grid of 26,000 miles of transmission lines is operating under great strain. It is part of the 115,000-mile western grid that stretches from British Columbia to northern Mexico, linking more than 700 power plants. Several major transmission corridors operate dangerously close to their capacity, including the now widely publicized Path 15, which links Northern and Southern California.

In January 2001, Northern California, which was unable to secure its accustomed electricity supply from the drought-stricken Pacific Northwest hydroelectric plants, suffered rolling blackouts when excess capacity in Southern California could not be transmitted through Path 15. An overstrained transmission grid is vulnerable to a loss of service at any location; for example, in early April, a windstorm knocked out a transmission line between the Northwest and Southern California, depriving Los Angeles of 3,000 MW of transmission capacity for ten days and causing a Stage 2 emergency ("U.S. West Power Line Shut," 2001).

There has not been much of an effort to build new transmission lines in California. Since the restructuring of the electricity industry, utilities have been reluctant to invest in new transmission. New transmission facilities traditionally satisfied state requirements that utilities serve their native loads, but new transmission assets today are more likely to benefit a larger electric market. The North American Electric Reliability Council (NERC) has estimated that annual investments in new transmission facilities have been declining by about $100 million a year for the past two decades; in the same period, load growth has been increasing.

The Electric Power Research Institute (EPRI) estimates that between 1989 and 1999 electricity demand in the United States has risen by roughly 30 percent, while additional transmission capacity has grown by only 15 percent (National Electrical Manufacturers Association, 2001). Plans for the next ten years entail a nationwide increase in circuit miles of only 3.5 percent. New transmission line costs range from about $160,000 per circuit mile for an overhead 115 kilovolt (kV) line to $3.7 million for a buried 230 kV line (Fuldner, 2000).

Load-centered generation relieves much of the strain on the transmission grid imposed by central station generation and allows utility planners to defer transmission line investments. Many analysts have estimated the value of such deferrals, which vary widely depending on the rate of demand growth, siting, and regulatory concerns, and the costs of local versus remote generation. The Distributed Power Coalition of America values these savings at up to six cents per kilowatt-hour (Distributed Power Coalition of America, 2000), Arthur D. Little values transmission upgrade deferrals at $30 per kilowatt-year (Little, 1999), and the FERC puts wheeling fees[12] at about $22 per kilowatt-year (Geschwind and Flucke, 1998).

Coles et al. (1995) find a wide range of benefits with an average value of 0.8 cents per kilowatt-hour. Using a different methodology, Wenger, Hoff, and Pepper (1996) find transmission deferral benefits of about one cent per kilowatt-hour, while the Vermont Department of Public Service (1999) suggests a range of 1.4 to 7.2 cents per kilowatt-hour. Shirley (2001) examines the actual transmission costs of 93 large utilities (from their FERC filings); for a representative utility with relatively high costs, a conservative estimate for the value of deferring a transmission investment for one year is in the range of $16 to $337 per kilowatt.

Load-centered generation also reduces the losses in transmission, which typically range from 2 to 5 percent of generation (or about 1 percent per kilometer at 500 kV) (Energy Information Administration, 2001). These losses

12 "Wheeling" is the process of transporting electricity across an area without using it. The owner of the transmission lines typically charges the supplier and customer for their use.

are valued at $50 per kilowatt-year (Little, 1999), and 0.6 cents per kilowatt-hour (Coles et al., 1995).

Reducing the strain on the transmission grid yields other, less readily quantifiable benefits. LCG can contribute to improving the reliability of the grid and the quality of power delivered. Greater margins make transmission lines less prone to sag or failure. In Reliability Must Run (RMR) areas (that are locally capacity-constrained), less-efficient and more-expensive generating units must run ahead of more desirable but remote and inaccessible units; in these circumstances, new LCG can free up the transmission grid to allow for wheeling cleaner, cheaper power.[13]

LCG also has the potential for operating in a combined heat and power (CHP) arrangement. As LCG plants are located close to their users, users may be able to use the plant's waste heat for water, air, or process heating. Valuations for CHP vary with the customer's heat load, proximity to generation, and fuel cost and generation technology. One study of typical industrial sites in California suggests a value from heating fuel savings of 1.5 cents per kilowatt-hour (Onsite Sycom Energy Corporation, 1999).

Costs Associated with LCG

There may be some costs associated with LCG that are greater than for the alternatives. Urban areas may have higher capital and operating and maintenance costs than remote rural areas, although the land acquisition costs are not an issue for repowering on a site already owned by a utility if the site cannot be used for other purposes. The smaller generation units typical of LCG may have higher capital costs per megawatt than larger units; conversely, the smaller unit size may allow for staged capacity expansion to meet demand growth, providing savings from capacity investment expansion. Associated with the possible health and environmental impacts of locating generation in heavily populated areas, emissions permits and tradable credits may be more expensive in those areas.

LCG Can Help Prevent Power Outages

Power outages captivate the media and public attention, as seen in recent months in California, and can in fact wreak substantial economic damages on electricity consumers. The losses depend on the frequency and duration of outages, the amount of warning time, and the nature of the consumers' activities. Some manufacturing operations must discard work in progress and restart processes and equipment if they suffer only a one-second brownout, whereas retail stores may suffer losses roughly in proportion to the duration of the outage. LCG can preclude outages in the local service area by insulating it from failures in the transmission grid or loss of capacity elsewhere and can also reduce the likelihood of outages anywhere by improving the reliability of the grid.

A variety of methodologies have been employed to estimate the economic costs of power outages. The first entails asking residential, commercial, and industrial customers what losses they have suffered from actual outages or would expect to suffer in hypothetical outages. A survey of this literature reports a typical valuation of 0.6 cents per kilowatt-hour (kWh), or $35 per kilowatt-year (Little, 1999). One survey of time-sensitive businesses values losses for a one-hour outage at from $41,000 for a cellular phone relay to $6.5 million for a brokerage house (Little, 1999). A semiconductor manufacturer reports that a 20-minute outage at a fabrication plant would cost it $30 million (California Public Utilities Commission, 2000). An extensive survey in California following the western states outage of August 1996 found a wide range of loss valuations, from the costs of labor, raw materials, lost products, equipment damage, and canceled contracts. For commercial and industrial customers, 56 percent of respondents reported losses from just $40 up to $5 million (California Energy Commission, 1997).

As the demand for electric service reliability varies among customers, so should their willingness to pay for it. In recent years, utilities have sought to capture these demand heterogeneities by offering interruptible service contracts, so that the marginal expenditures on service improvement matches the marginal customer benefit. Customers' valuations of reliability may be inferred from these contracts. A survey of this literature found a wide range of valuations of unserved demand: from $25 to $60 per kilowatt-hour for commercial customers, $10 to $20 for industrial customers, and $1 to $10 for residential customers (Caves, Herriges, and Windle, 1990).

ENVIRONMENTAL ISSUES: LOCAL CONCERNS AND NOx

Developing new LCG facilities will not be free of environmental concerns, including those related to emissions and "not in my backyard" responses by the public. Before any proposed plants in excess of 50 MW can be approved, applications must be reviewed according to provisions of the Warren-Alquist Act and the California Environmental Quality Act (CEQA).[14] Issues examined during the year-long proceedings include public health and safety, air and water quality, hazardous materials, environmental impacts, land use, and engineering design. The process involves staff analysis as well as public participation.

13 Three-quarters of California's generating units are designated RMR.

14 Generators with a capacity under 50 MW must also comply with CEQA, but do not require CEC approval.

California Governor Gray Davis has declared the construction of more power plants to be a top priority during the current energy crisis. He has issued several executive orders intended to boost generation in the state and to streamline the permit process. Yet the concern of neighbors about air pollution and health effects has become apparent in the public review of the various proposed plants. Despite strict environmental standards and approval by the relevant authorities, local reactions have already deterred the siting of at least one plant in Southern California: the Nueva Azalea power plant proposed by Sunlaw Energy Company in South Gate. In contrast, the Metcalf Energy Center, a joint venture of Calpine Corporation and Bechtel Enterprises, is planned for South San Jose and is currently under review by the CEC. This plant has been welcomed by many of its neighbors, even on environmental grounds. These two examples, which illustrate the range of uncertainties involved in gaining approval for new power plants, are described in more detail in the following sections.

Proposed South Gate Plant

With the proposed 550 MW natural-gas-powered plant, Sunlaw promised $1 million in neighborhood improvements, $150,000 per year in community scholarships, and $6 million in annual tax revenues to the community of South Gate. Opponents conceded that the plant would likely emit less air pollution than the diesel truck depot the project proposed to replace, perhaps even less pollution than was already in the surrounding air on particularly smoggy days. The South Coast Air Quality Management District (SCAQMD) gave the project preliminary approval as it would have met all air quality regulations and would help to ease the power crisis. Yet claims of “environmental racism” in this predominantly Hispanic working-class community, plus a hunger strike by the mayor of South Gate, eventually led to the withdrawal of Sunlaw’s plans.

Proposed San Jose Plant

Metcalf Energy Center is a $300 million, 600 MW power plant proposed for a site south of San Jose. Cisco Systems Incorporated, along with San Jose’s mayor, have opposed the plant fearing its possible health and safety effects, particularly on workers at the neighboring office complex proposed for 20,000 Cisco employees. However, the board of the Silicon Valley Manufacturing Group, which ironically includes Cisco Systems, supports the project, as do local chapters of the Sierra Club, the American Lung Association, and the state’s mainstream environmental groups. In addition to supporting power for Silicon Valley’s high-tech industry, the support stems from the fact that the plant is much cleaner than current plants, is located near demand, and can be plugged into the existing infrastructure, including a major substation and natural gas transmission facilities.

NOx Issues

The increased demand for power has important implications for operational impacts associated with new plants, and increased generation capacity of older plants, within the South Coast Air Basin (SoCAB) and under the jurisdiction of SCAQMD. Pursuant to the Regional Clean Air Initiatives Market (RECLAIM) program, tradable allowances for nitrous oxide emissions must be held by affected sources in the SCAQMD. Facilities within the RECLAIM program have the option of complying with their allocation allowance by either installing equipment that reduces the amount of emissions or purchasing RECLAIM Trading Credits (RTCs) from other facilities.

In 2000, power producers purchased 67 percent of the NOx RTCs while only accounting for 14 percent of total RECLAIM allocations for that year. RTC prices increased from $4,284 per ton traded in 1999 to approximately $39,000 per ton traded during the first ten months of 2000, affecting production costs of the power plants supplying California’s electricity demand. The prices for NOx emissions credits increase during times of peak demand, as the generating units with the highest NOx emissions rates operate during these periods.

On February 8, 2001, Governor Davis issued Executive Order D-24-01 directing the California Air Resources Board to establish a State Emissions Offset Bank to allow facilities to pay mitigation fees to compensate for increased operations. Mitigation fees will be used to maintain state and federal air quality standards by cleaning up facilities and mobile sources that pollute the air, such as older power plants and diesel machinery.

Given the rising costs of RTCs, a number of facilities, including power producers, have filed permit applications to install controls that will significantly reduce emissions and the associated demand for RTCs. While this is expected to cause RTC prices to drop, there is a lag between the decision to install controls and the operation of the controls. In the meantime, a working group that includes power producers, other RECLAIM facilities, environmental groups, the Environmental Protection Agency (EPA), the Air Resources Board (ARB), CEC, and interested legislative representatives is scheduled to meet to develop rule amendments that will stabilize prices in the short term.[15]

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[15] To reduce emissions credits prices, SCAQMD has recently considered modified rules that separate power plants from the rest of the RECLAIM market. In a pilot program, generators would have to install air pollution control equipment on an expedited schedule and would be able to purchase NOx emissions credits at $7.50 per pound. Assuming that this price continues to be available throughout the period of the market model, our estimate of the value of the new municipal generation is $439.3 million assuming $5 / MMBtu gas prices and $524.5 million assuming $7.50 / MMBtu gas prices.

Environmental Benefits of the Proposed LCG Generation

The new generation proposed by the municipal utilities would be cleaner than the generation at all of their existing sites, with the exception of the Broadway 3 steam generating unit in Pasadena and the Grayson steam units and combined cycle gas turbines in Glendale. The Broadway 3 steam generating unit in Pasadena and the combined cycle gas turbines in Glendale are equipped with a selective catalytic reduction (SCR) unit, which injects ammonia gas into the flue gas and passes the emissions over a catalyst, reducing NOx by more than 50 percent. The Grayson steam units employ low-NOx burners and flue gas recirculation systems to reduce their emissions. Figure 12 shows the relationship between the average NOx emissions from the proposed new generation and emissions from the existing plants.

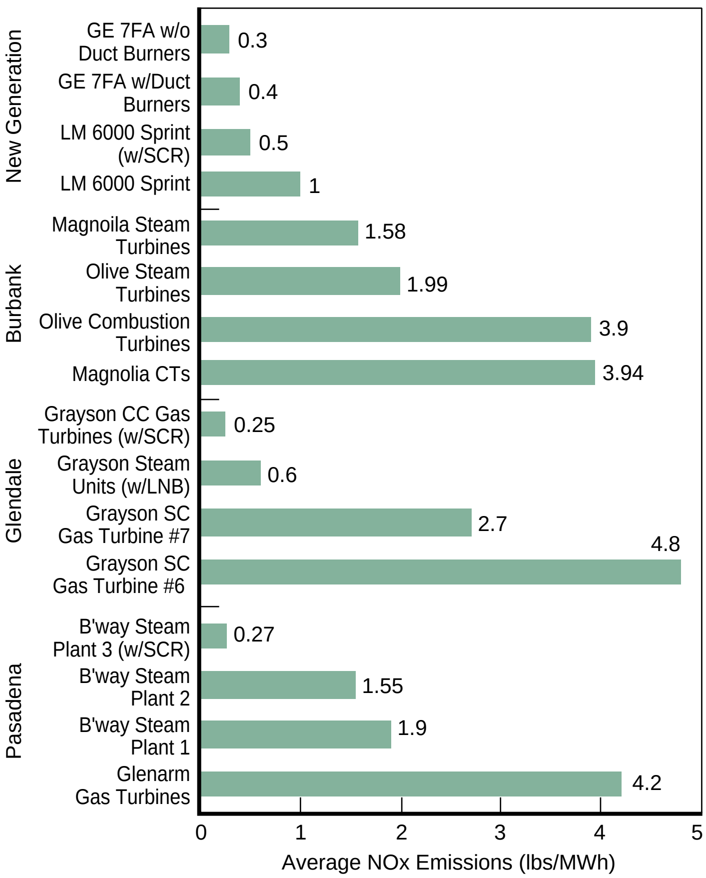

Figure 12—Nitrous Oxide Emissions from the Proposed LCG Plants and Existing Plants

LCG OFFERS SUBSTANTIAL BENEFITS FOR THE CITIES AND CALIFORNIA

The analysis presented here shows that if the cities of Burbank, Glendale, and Pasadena repower their existing generation sites, the new plants will benefit not only the cities, but the state of California as well. The new plants will supply the cities' own needs and allow them to sell power to the state at cost-based rates. The value of this generation for California under a set of reasonable assumptions is potentially between $466 and $585 million—or about $5.30 to $6.64 per MWh of new generation—for the ten-year period from 2002 through 2011. The only load-centered benefits included in the model are reduced transmission losses.

Because the municipalities can borrow money cheaply which may allow them to build the facilities more cheaply than private sources, their costs will be relatively low and so will the rates they charge. The facilities will be owned by the cities and their residents, thus providing employment and tax revenues for the state. Because the new generation will be located near load centers, they will reduce some transmission losses and alleviate pressure on the transmission system as a whole. In addition, the new LCG plants will be considerably cleaner than the plants that currently operate on these sites.

Load-centered generation represents a valuable part of California's energy generation portfolio. This study looked at only three of Southern California's 12 municipally owned utilities, but it is reasonable to assume that similar potential exists at all of the state's municipally owned utilities and that they could, conceivably, generate thousands of megawatts of new, inexpensive, and clean electricity throughout California. Given the apparent benefits to the state, there may be opportunities for the state to encourage municipalities to develop this new generation, particularly on existing generation sites, and to make existing generation more efficient. Incentives could come in many forms, including subsidized financing, long-term state contracts or investments, expedited permitting, and greater flexibility on emissions offsets.

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