# Designing an Energy Portfolio

## The League and Energy

**THE ELECTRICITY NEEDS** of California are currently met by a mix of about 56,000 MW of in-state capacity and more than 6,200 MW of capacity in nearby states. The latter is largely coal-fired; in-state capacity is diverse, but more than half is natural-gas-fired. And most of the natural gas capacity is owned by independent "**merchant generators**," not regulated by the California Public Utilities Commission. The deregulation legislation of 1996 required utilities to sell much of their generation, so they now own only 42 percent of the total capacity.

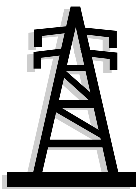
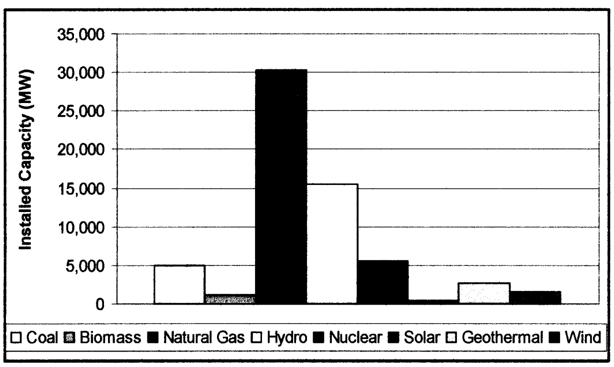


**Figure 1**
**Capacity by Fuel/Technology Type**




As a result of the financial problems faced by the investor-owned utilities in 2000 and 2001, the California Department of Water Resources (DWR), negotiated long-term contracts with the merchant generators. During the crisis many of these merchant generators had sold into the **wholesale spot market** at exorbitant prices. The prices negotiated by DWR are not exorbitant but they are high, and most contracts run until 2010. Utility customers are paying these costs. Most of the natural gas-fired generation that has come on line in the last several years is being sold into the spot market. The price of power from these plants largely reflects the current market rate. Since these plants are fueled by natural gas, they are affected by natural gas market conditions. Natural gas prices, notably volatile during 2003, have become more stable since, but are notably higher, averaging more than $6 Mmcf.

The Energy Commission attributes the stabilization of spot market prices since 2001 to three factors.

- Energy-efficiency measures by consumers.
- Addition of the 9,400 MW of new capacity, along with an economic downturn.
- Dramatic reductions in the amounts of energy purchased on the spot market.

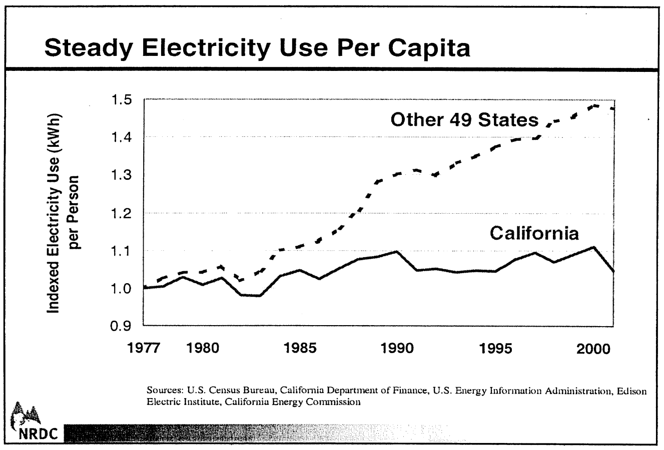
The future is not bright, however. With the economic recovery now under way, demand is growing faster than supply. Although construction permits have been issued for six large merchant plants with almost 4,000 MW of capacity, none are expected on line before 2006. In addition, drought throughout the West has reduced the amount of hydropower that can be imported from the Northwest. Recognizing the need to plan for peak power demands, the CPUC has set a 15 percent reserve capacity requirement. Assuming a 1.5 percent annual increase in peak demand, (it is currently 3.5 percent in Southern California) capacity requirements in 2030 will amount to 92,000 MW. (Currently 62,000 MW)

More than 40 percent of the **natural gas-fired generation** in the state was built in the '50s and '60s. These plants are as much as 50 percent less efficient than the new plants, and over the coming decade many of them will be retired or rebuilt; approximately 3,000 MW of capacity was retired just in the past three years. But some of these plants are strategically located near the demand load, and because of increasing congestion of the transmission system, they receive a pricing bonus associated with "**reliability-must-run**" (RMR) contracts. In-state gas production presently meets only 15 percent of California's needs. Out-of-state supplies are adequate throughout this year, but, with growing reliance on natural gas to generate electricity, concerns about the integration of the electricity and natural gas markets continue to mount. Merchant generators, unlike regulated utilities, are not obligated to serve electricity customers; if it is more profitable, they may sell their natural gas into the gas markets, rather than use it to generate electricity. In any case, short-term supply shocks will lead to increases in spot market electric prices. Demand-side management and increased use of renewable resources are the near-term options to dependency on natural gas.

**Renewable resources** include geothermal, biomass, small hydro, wind and solar. During 2002, the legislature passed SB 1078 which requires the investor-owned utilities to increase investment in renewable energy one percent annually until each utility provides 20 percent of its energy from renewables. Southern California Edison is already meeting this requirement for 2004. PG&E currently is at about 14 percent and San Diego Gas and Electric less than 4 percent. In mid-2004 4,400 MW of renewable capacity was on line. Almost 14,000 MW more will be required by 2030. Because of ecological concerns it is unlikely that more small hydro will be developed. Geothermal and wind resources are considered abundant, but are located at considerable distances from load centers. Wind and solar are intermittent, estimated to be available about 25 percent of the time (often but not always near times of peak demand).

Governor Schwarzenegger has enthusiastically called for more investment in **solar rooftops**. Certainly photovoltaic panels can benefit local homeowners in many parts of the state. However, an average residential roof can only accommodate 2 kW of panels (less than half of the power needed at peak power periods). About 125,000 new homes are built in California each year, and solar rooftop systems on 15 percent of these would provide 35 to 40 MW of new capacity. Solar panels can be considered a contribution to peaking power capacity, rather than baseload, as it will be available during daylight, when air-conditioners are generally in use.

Both the Energy Commission and the CPUC have made **energy efficiency** their top priority: The goal is to reduce energy use, and decrease peak power demands. For nearly a decade, utility customers have paid on their monthly bills a "public goods charge," and one of the benefits of those monies has been investments in energy efficiency retrofits. The result has been dramatic: Energy use in California is about *half* of per capita use for the nation as a whole.




This past year, the three major utilities have been allowed to include energy efficiency investments in their **capacity procurement planning**. It should be noted, however, that investments in energy efficiency – beneficial in terms of diminishing resources and air pollution – often do not reduce *peak* power demands.

Reductions in peak demands come about largely because of customer response to a definite signal. One such signal may be a radio or television announcement that electricity demands are getting close to capacity, and asking customers to cut back on power use. Some customers, usually larger ones, also negotiate **"interruptible" contracts** with their utilities: In return for favorable prices most of the time, they agree to have their service cut back when reserve margins shrink to a particular point. The present interruptible load is just short of 1,500 MW.

**Dynamic pricing** is a technique that could allow the state to not invest in 2,000 MW of new capacity over the next 25 years. The League has already had opportunities to speak on behalf of this vision. During the past several years, California has paid to install 22,000 real-time pricing meters at commercial and industrial sites. These meters show customers at 15-minute intervals

the actual cost of power so they may plan their use. The costs currently range from 5 cents per kWh at 2 a.m. to 33 cents per kWh at 4 p.m. on a hot summer day. It is likely that dynamic pricing will become a reality for residential customers before the end of the decade. Each special meter is estimated to cost a little more than $100.

A growing trend is the use of **distributed generation** (DG). This refers to small, localized generation systems, close to the load that they serve. DG enthusiasts point to the avoidance of dependence on the transmission system and the economic opportunities that may be available for facilities to generate their own power apart from the utility grid – especially if they can sell any excess power back to the utility. DG is proving to make good economic sense for facilities that can use solar, wind or biogas. It is not succeeding for those sites that would use natural gas-fired turbines for power generation, because of local air emission requirements.

A major consideration still to be clearly addressed involves issues of **direct access** and "**departing load**." The deregulation legislation of 1996 allowed utility customers to leave their utility and to contract directly with merchant generators for power. A significant number of industrial and large commercial customers did just that at a time when wholesale energy prices looked attractive. But in 2000-2001, when wholesale power prices sky-rocketed, these same customers sought to return to service with the utilities to obtain power at the regulated retail rates. The direct access policy presents a dilemma for utilities, as they likely will have to serve as the default provider if a merchant generator fails.

Late in 2001 the CPUC ruled against any further direct access contracts. About 14 percent of total customer load remained with the merchant generators, and when it became clear that these customers were not sharing in the high-cost, state-negotiated DWR contracts, the CPUC instituted a 2.7¢ per kWh charge on direct access power.

The California electricity system should be flexible enough to take advantage of new technologies and energy sources, and yet be stringent enough to provide economical, reliable service. Integration of the electricity system requires some control over the mix of sources: with the ability to plan for adequate capacity, to promote the use of renewable sources of electricity, and to provide incentives for efficiency and conservation.