Section 3: Resource Adequacy

CAN CALIFORNIA GENERATE ENOUGH electricity to meet its customer's needs? The answer is yes—99.9 percent of the time. But that one-tenth of one percent *is* cause for concern in a constantly growing state, one whose economic well-being is increasingly dependent on energy-intensive technologies. Further causes for concern are periodic droughts in the Northwest, which supplies California large amounts of hydropower, and the fact that nearly half of the in-state generating capacity is more than 30 years old. (*See Section 2, "How Has the Electric Industry Changed Since 1996?"*)

California's system of power plants is diverse, in terms of types of facilities (from gas-fired to wind-powered), how the plants are operated and where they are located. About 20 percent of the power used in the state is even generated out-of-state. California is part of an interconnected western grid, which includes most of the 11 western states, as well as portions of British Columbia, Alberta and Baja California.

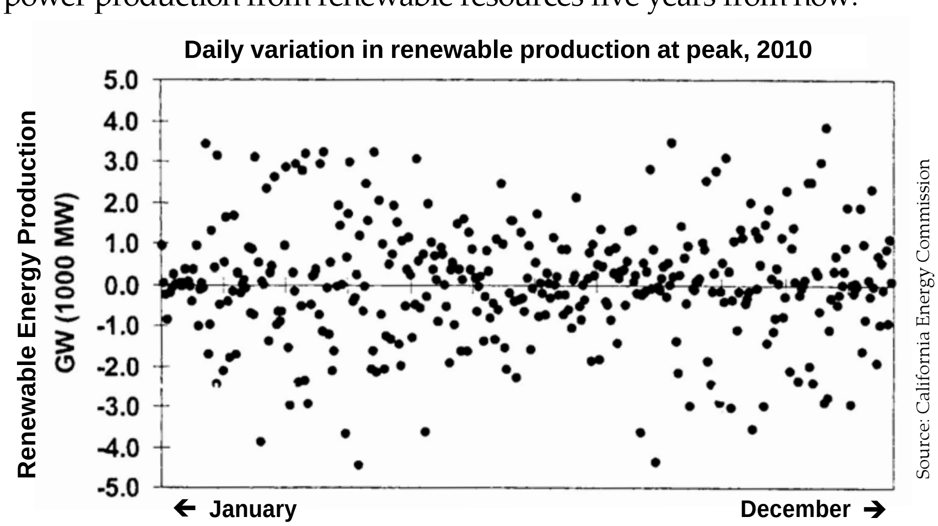
The diversity of the system

The number, type and location of power plants obviously affect the supply mix of electricity each year. Power plants in California and throughout the West operate in these modes:

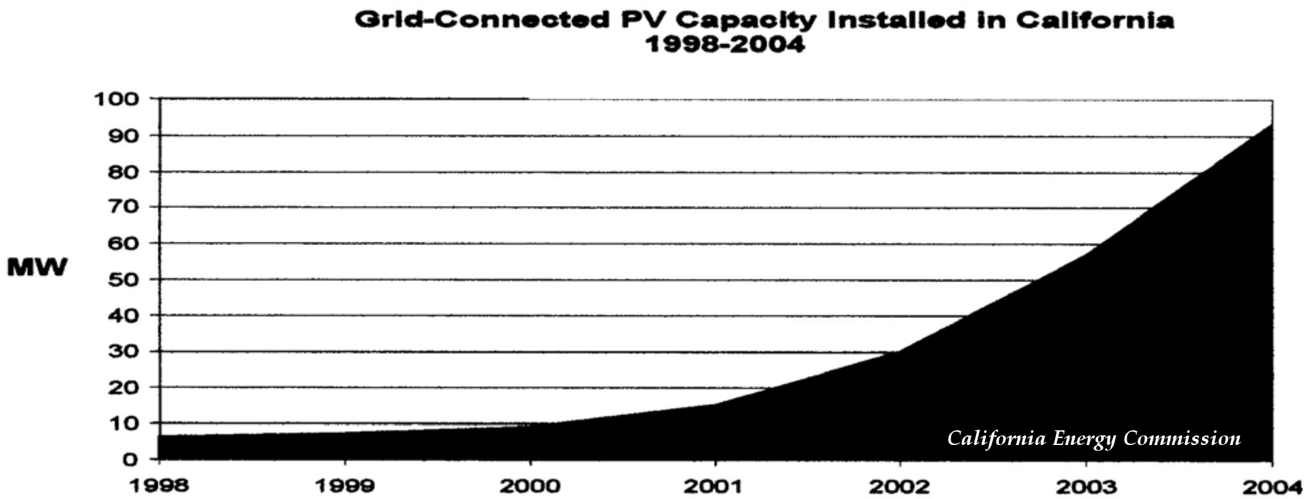
- Baseload duty cycle
- Intermittent duty cycle
- Intermediate or load-following duty cycle
- Peaking duty cycle

Baseload power plants, once started, operate continuously until shut down again for maintenance or refueling. Nuclear, coal-fired and geothermal power plants fall into this category. These plants cannot be brought up to full capacity quickly—and once on line they are generally run at full capacity. So are some hydroelectric power plants with continuous water flows, such as those on the Columbia River, and cogeneration power plants (where power production is secondary to another continuous thermal industrial process, such as oil refining).

Intermittent power plants—wind, solar and some hydroelectric facilities—operate as much as they can, contributing to California's annual electric supplies *only* when their primary source of energy is available. Increasing amounts of wind and solar power in the resource mix present additional challenges to system reliability. Below is a projection of the variability in daily peak power production from renewable resources five years from now:



The state's emphasis on intermittent renewables is a something of a two-edged sword—adding to the state's generation resources but also increasing the amount of generation that cannot be definitely relied upon at any given time. The expected variance in energy production from one day to the next will have significant operational implications for CAISO. Solar energy is somewhat better in this respect, in that its availability tends in a general way to correspond to the rise and fall of customer demand. Solar is location specific—that is, some



areas have more of it than others—but in many parts of the state it can help meet peak load requirements. Wind energy is notably more cost-competitive than solar; however, the wind seldom blows sufficiently when the state has major power needs.

Intermediate or **load-following** plants step in to provide additional power when needed. Hydroelectric plants, other than those with continuous water flows, are particularly effective for load-following, picking up the load quickly when the intermittent plants go off line.

Finally, the **peaking** power plants are called on only when demand reaches its maximum. Peaking service is generally assigned to older, less-efficient plants, and their power tends to be very expensive.

Through much of the year, 70 percent or less of total system capacity suffices to meet typical daily peak demand in the state. Full capacity needs to be called upon only to meet periods of peak demand, typically hot summer afternoons. This usually amounts to no more than 100 hours out of the 8,760 hours in a year.

Hydropower plays a critical role in the availability of electricity. When rain and snow, and the resulting runoff, are plentiful, hydroelectric facilities are used to the maximum. Other power plants, mostly gas-fired, are backed down or idled. When conditions are dry, these other plants step in and produce power. This system is usually effective. But the circumstances in 2000 (identified in Section 2) show what can happen when drought conditions and idling of gas-fired plants converge. This situation also points out how interconnected the West is, in terms of importing and exporting power. Drought in the Pacific Northwest sharply reduced California's ability to import hydroelectricity from the Columbia River system.

Pumped storage is a special form of hydropower. In a pumped-storage plant, inexpensive, off-peak energy generated by baseload plants is used to pump water from a lower reservoir

Source: California Energy Commission

up to a higher reservoir. When there is need for peaking power, the water is released from the upper reservoir to flow through a hydraulic turbine and drive a generator. (Of course, it isn't magic—more power is used pumping uphill than is generated on the downhill trip—but the greater value of the peaking power so generated makes this process economic.)

Location of power plants can affect adequacy

All but five of California's counties have some electric generating facilities. In some counties these generating plants play a special role in maintaining electric system reliability, providing voltage support and other grid reliability services.

CAISO has designated more than 100 generating units as "Reliability Must Run" (RMR) because of their locations within one of seven "local reliability" areas. Most RMR units are in northern California (i.e., the PG&E service area), but there are a number in the Los Angeles and San Diego areas as well. In fact, most units in San Diego are RMR-designated facilities. Most such facilities are either hydroelectric or natural gas power plants, but they can also be waste-to-energy and geothermal power plants. Many of these RMR facilities are older, less efficient plants, and a few may need to add expensive controls to reduce air emissions. For these reasons, and because they run sporadically (and so make less money), some RMR plants are in danger of being shut down by their owners. The map on the previous page shows RMR locations.

The state has made a concerted effort to increase reliability in a number of areas. New power plants have been built in San Diego, notably the 590 MW Otay Mesa Power Plant. In addition, The Path 15 transmission line near Los Banos has been upgraded, thus strengthening the ability of the grid to deliver power between the northern and southern parts of the state.

Diversity of facilities also enhances adequacy

Hydroelectric facilities were the main source of electricity for the state during the first half of the 20th century. The current system has 386 hydroelectric generating plants, most of them in northern California. On average, they supply 12 to 18 percent of California's annual power needs, but with a wide range of variation depending on the amount of precipitation.

Oil-fired power plants were developed in the late 1930s and peaked between 1950 and 1960. These plants were built on coastal and estuary sites in northern, central and southern California to take advantage of large volumes of cooling water and the ability to receive fuel from seagoing tankers. Because of the oil embargo in the mid-1970s and increasingly stringent air regulations, most of these plants were modified to run on natural gas. Many of the RMR units mentioned previously were originally oil-fired, but now all are natural-gas fueled. No power plants in the state are currently fueled by oil.

Seven **nuclear power plants** were added to the California grid between the 1960s and the 1980s. PG&E's 63 MW Humboldt Bay plant was closed in 1976 after damage resulted from a moderate earthquake on a previously unknown fault. Sacramento Municipal Utility District's 913 MW Rancho Seco plant was closed in 1989 by public referendum, and SCE's 436 MW San Onofre 1 was closed in the early '90s because costs of modifications were considered uneconomic.

At this time, nuclear power comprises 13 percent of the state's electricity supply: 2,174 MW of power from PG&E's two Diablo Canyon Power Plant units, 2,150 MW from SCE's San Onofre Units 2 and 3, and 1,008 MW from California utilities' share of power from Arizona Public Services' Palo Verde Plant. (San Diego Gas & Electric owns a minority share in San Onofre.)

The California plants, which use pressurized reactors, are scheduled for significant refurbishment over the next several years. Both SCE and PG&E expect to spend about $800 million to replace their steam generators. The CPUC has found these projected expenditures to be reasonable—especially in light of the consistently high capacity factors of the plants. Nevertheless, there are important environmental concerns associated with water discharges from the plants that regional water boards believe have not been adequately addressed. The utilities are currently developing proposals to mitigate these problems.

These plants have 40-year licenses that will expire about 2025, and both utilities anticipate applying for license extensions for up to 20 years. The federal Nuclear Regulatory Commission has exclusive jurisdiction over license renewals; however, the possibility of an Energy Commission preview of the applications was raised at a recent CEC workshop.

California has only a few small in-state **coal-fired power plants**, which collectively generate only 560 MW (one percent of state electricity needs). Much of the "coal-fired" capacity in the state is actually fueled by petroleum coke—a waste product of petroleum refining. California does import energy from coal-fired plants in other Western states.

California produces about 40 percent of the world's **geothermal electricity**, but the 2,600 MW total only amounts to about five percent of state power needs. Geothermal facilities can only be built where underground hot water or steam is available to be drawn up to the surface; Sonoma and Lake Counties have the largest share of geothermal plants. Geothermal plants in northern California peaked in the 1980s when the steam reservoirs began to be depleted. A number of potential geothermal sites have been identified in the Salton Sea area and in the northeastern part of the state. They may be developed over the next decade to meet additional requirements for renewable resources.

Most **waste-to-energy power plants**—which burn municipal solid waste, logging residues, mill wastes, agricultural residues and landfill gases—were constructed in the 1980s and, to a lesser degree, in the 1990s. About 100 of these plants are scattered throughout the state, generally where the "fuel" is located. The waste-to-energy plants decrease the air pollution that would result from open burning of the wastes and from the seepage of gas from landfills. These plants have a combined capacity of 1,071 MW and provide two percent of the state's energy needs.

Between 1981 and 1988, nearly 17,000 small- to intermediate-sized **wind turbines** were installed in California in clusters commonly referred to as wind farms. Currently, California has four major wind resources areas with 1,818 MW of total capacity. Kern County has the largest number of wind farm sites. Because wind-powered plants cost about the same as new gas-fired plants, much attention is being paid to expanding this source of renewable energy. Development of new projects, such as in the Tehachapi Mountains, is currently constrained by the lack of transmission lines to deliver the power to where it is needed. Wind-powered plants currently provide two to three percent of average annual electricity. In the southern part of the state, wind generation generally is greatest late at night, and consideration is being given to using that energy for pumping water uphill in new pumped-storage hydro plants.

Like wind-powered plants, **solar thermal power plants,** which were built in the late 1980s, are geographically limited. They are economic only where there is ample sun, such as in the desert. These plants often also use natural gas to provide backup power and operate 24 hours a day. California currently has about 400 MW of solar thermal capacity, supplying less than one percent of the state's needs. However, SCE has recently proposed further procurement of 500 to 800 MW of solar thermal capacity.

Solar photovoltaic (PV) systems are becoming increasingly common in the state, though their total output is still small. Approximately 93 MW of rooftop PV panels have been installed here. Because their output is still much more expensive than that from the sources discussed above, these systems are generally subsidized, in the expectation that greater production of the panels will reduce costs. There is currently a subsidy of $3 per watt for installing rooftop PV panels on residences. Furthermore, a pilot program that will reimburse owners of PV systems for power provided to the grid will begin before the end of 2005. These systems will have two-way meters to determine whether, overall, the system's owner takes more power from the grid or delivers more power to it; if the latter, the user will be paid for the net amounts delivered. Such a setup is referred to as **net metering.**

Other sources of supply

Distributed generation (DG) is the generation of electricity from facilities smaller than 10 MW. A potential growth sector, particularly in response to current supply concerns, DG comprises the following:

- Diesel engines
- Fuel cells
- Small and "micro" turbines and reciprocating engines
- Solar thermal and solar PV
- Small wind turbines

Most of the DG currently installed in the state is in the form of on-site diesel back-up generators. They are intended for emergency use and would not be able to meet local air emission standards for routine operation.

The Energy Commission has offered rebates for "emerging" renewable systems since 1998, and these rebates, funded by the Public Goods Fund (which in turn is funded by a charge on customer bills), have supported the installation of over 40 MW of renewable DG—mainly residential photovoltaic (PV) systems.

In 2001 the CPUC established a Self-Generation Incentive Program funded annually at $125 million. This program offers rebates to grid-connected DG between 30 kW and 1 MW in size. More than 20 MW of PV systems have received rebates from this program which also is financed by the Public Goods Fund. PV generation is also supported by a state tax credit that amounts to 7.5 percent of system costs (or $4.50 per watt, whichever is less). Businesses are eligible for a federal tax credit of 10 percent of the cost of their systems.

Energy efficiency and demand-side management (DSM) measures have been implemented to reduce electricity demand and are proving increasingly effective. DSM includes a variety of approaches, including energy efficiency and conservation, building and appliance standards, load management and fuel substitution. (*For more, see "negawatts" in glossary.*)

Since 1975, energy efficiency and DSM have displaced output roughly equivalent to that of eighteen 500-megawatt power plants from peak demand. As more new buildings and homes are built under increasingly strict standards, the annual savings have increased steadily, from 600 MW in 1980 to 5,400 MW in 2000. Savings from energy-efficiency programs run by utilities and state agencies have also increased since 1975, from 750 to 3,300 MW. Blackouts were avoided during the summer of 2001 thanks in large part to the energy conservation programs that reduced demand by over 10 percent.

The California Energy Commission is responsible for defining building and appliance energy efficiency standards. During 2004, the commission set new standards for a number of additional appliances. Although the manufacturers challenged these new requirements on the grounds that they were not federally mandated, the courts supported the commission's initiative. In addition, California Title 24 building standards have been revised to be about 25 percent more rigorous than they were; the new standards are to go into effect in October 2005.

Energy Commission staff recently compared the cost of *reducing* energy demand through energy-efficiency programs with the cost of *meeting* energy demand by generating power. The cost of demand reductions through programs instituted from 2000 through 2004 averaged 2.9¢ per kWh. The cost for baseload generation was 5.8¢ per kWh—*and 16.7¢ per kWh at peak load*. (The peak time period is noon to 7 p.m. on weekdays between May and October.) The year 2004 offered the greatest first-year savings, some 1,843 Gigawatt-hours from an investment of $317 million by the three electric IOUs. Most municipal utilities have declined to provide the commission any information about energy efficiency programs they have undertaken.