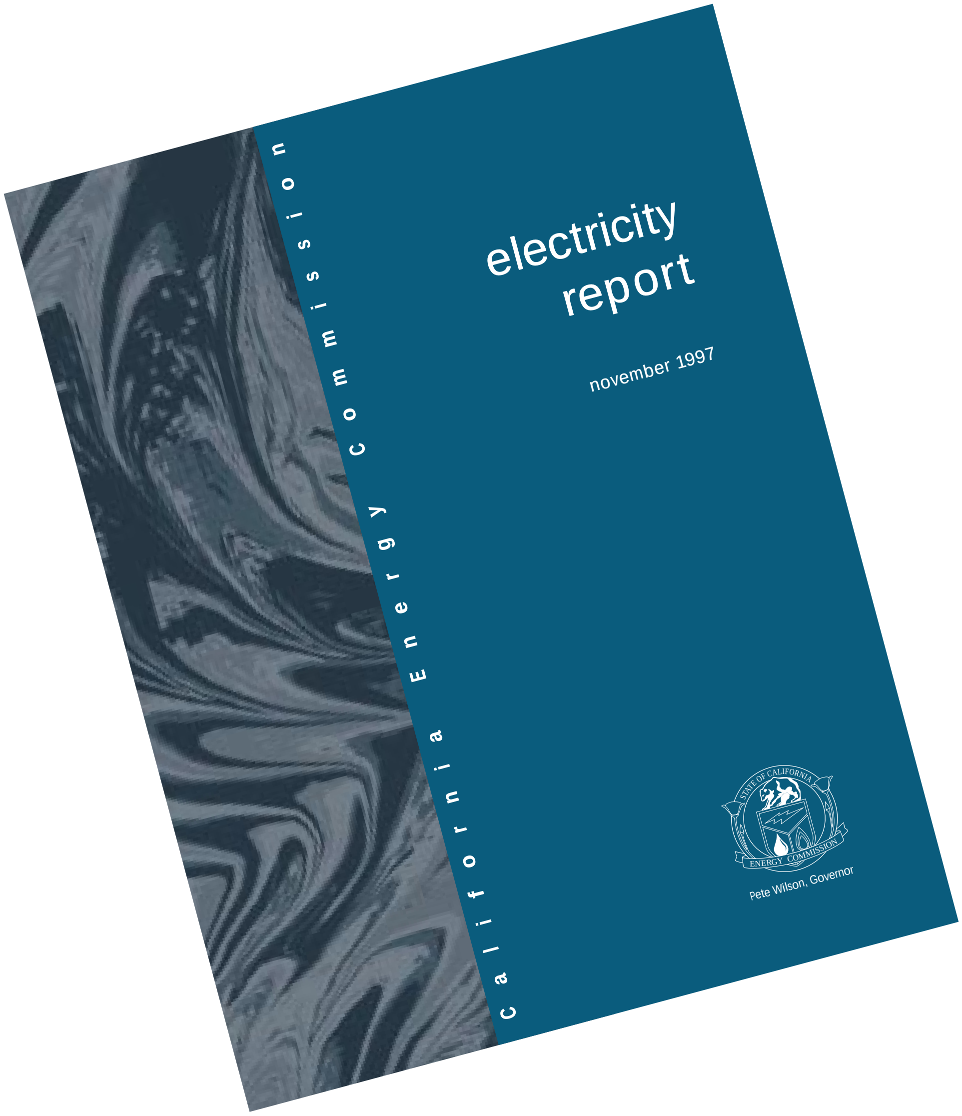

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ENERGY INFORMATION & ANALYSIS DIVISION

STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of:	)	**Docket No. 95-ER-96A**
	)	
Preparation of the	)	**ADDENDUM TO *ER 96***
1996 Electricity Report (ER 96)	)	**RE: NOI EXEMPTIONS**
	)	**(May 12, 1999)**

ADDENDUM TO *ER 96* RE: NOI EXEMPTIONS

Public Resources Code section 25540.6(a) provides an exemption from the Notice of Intention (NOI) requirements for a natural gas-fired power plant that is the result of "a competitive solicitation or negotiation for new generation resources." The Commission has reviewed requests for NOI exemptions on a case-by-case basis in accordance with Commission policies and procedures that were originally established in the 1994 ***Electricity Report*** and the Addendum to the 1994 ***Electricity Report***, and that were continued in the 1996 ***Electricity Report***. (See ***ER 96***, p. 75, fn. 1.)

Recently, the Commission issued a precedential decision under Government Code section 11425.60 declaring that power sales by natural gas-fired power plant projects to the California Power Exchange (PX), other power exchanges, wholesale or retail marketers, direct access power markets, or other power consumers are the "result of a competitive solicitation or negotiation for new generation resources" within the meaning of Public Resources Code section 25540.6(a). (*Blythe Energy*, 98-SIT-2, Order No. 98-1104-04.) The Commission has granted an NOI exemption to each natural gas-fired merchant project (i.e., a project operating in a competitive market and not supported by ratepayer financial guarantees) that has requested an NOI exemption since the precedential decision in *Blythe Energy* was adopted.[1]

While the precedential decision has reduced the time and resources required to process individual NOI exemptions, the Commission believes that it is possible and desirable to further

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[1] See, *Three Mountain* (Docket No. 98-SIT-3); *Otay Mesa Generating Company* (Docket No. 98-SIT-4); *Delta Energy Center* (Docket No. 98-SIT-5); *Elk Hill Power Project* (Docket No. 98-SIT-6); *AES South City* (Docket No. 98-SIT-7); *AES Antelope Valley* (Docket No. 98-SIT-8); *Pastoria Power Project* (Docket No. 99-SIT-1); *Midway Sunset Cogeneration Company* (Docket No. 99-SIT-2); *Metcalf Energy Center* (Docket No. 99-SIT-3); and *Newark Energy Center* (Docket No. 99-SIT-4).

streamline the siting process. As the Commission stated in the *Blythe Energy* decision, gas-fired merchant power plants that participate in a competitive electricity market are presumed exempt from NOI requirements pursuant to Public Resources Code section 25540.6(a). (*Blythe Energy*, p. 17.) ***ER 96***, however, states that the Commission will continue a case-by-case review of NOI exemption requests as established in the Addendum to ***ER 94***. That procedural guideline appears inconsistent with the precedent adopted in *Blythe Energy*. Establishing a clear and direct policy and corresponding procedures for a unified approach to NOI exemptions would eliminate the need to expend effort on what has become a *pro forma* exercise.

Therefore, the Commission hereby amends ***ER 96*** by revising Footnote 1 at page 75 to establish a blanket NOI exemption for gas-fired merchant power plants. The case-by-case review process announced in the Addendum to ***ER 94*** is suspended. Hereafter, any proponent of a natural gas-fired merchant power plant project may file an Application for Certification (AFC) without applying for an NOI exemption. The AFC shall comply with the requirements of Public Resources Code section 25540.6(b) and all other applicable legal requirements.

Dated: May 12, 1999

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AND DEVELOPMENT COMMISSION

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ACKNOWLEDGMENTS

The ***1996 Electricity Report (ER 96)*** was prepared under direction of the ***ER 96*** Committee: Vice Chair David A. Rohy, Ph.D., Presiding, and Commissioner Jananne Sharpless, Second Member. The Committee was advised by Tom Tanton, Rosella Shapiro, Celia Howell, Laurie ten Hope, and Bob Eller. Terry O'Brien and Jonathan Blees served as Project Manager and Committee Counsel, respectively, for the Committee and as principal authors of the Committee's orders, decisions, and notices.

ER 96 rests on an extensive public record developed not only for this proceeding but also in conjunction with the California Public Utilities Commission's (CPUC) electricity industry restructuring proceedings.

The Committee acknowledges the contributions made by many parties in this proceeding:

AES, Placerita, Inc
Adams & Broadwell
American Wind Energy Association
Ater, Wynne, Hewitt, Dodson & Skerritt
Bay Area Air Quality Management District
California Biomass Energy Alliance
California Cogeneration Association
California Department of General Services
California Department of Water Resources
California Legislative Conference of the Plumbing, Heating, and Piping Industry
California Municipal Utilities Association
California Public Utilities Commission
Calpine
Center for Energy and Economic Development
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City of Azusa
City of Burbank
City of Colton
City of Palo Alto
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Energy Resources Group, University of California, Berkeley
Environmental Defense Fund
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Fluor Daniel
Geothermal Energy Association
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Harbor Cogeneration Company
IBM
Imperial Irrigation District
Independent Energy Producers
Insulation Contractors Association
JBS Energy
Kern River Cogeneration Company
Lawrence Berkeley National Laboratory
Los Angeles Department of Water & Power
Marron, Reid & Sheehy
Merced Irrigation District
Midway-Sunset Cogeneration Company
Mobil Oil
Modesto Irrigation District
Monterey Bay Unified Air Pollution Control District
National Gas & Electric
Natural Resources Defense Council
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New Energy Ventures
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Solar Turbines
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Southern California Gas Company
Strategy Integration
Sycamore Cogeneration Company
Texaco
Turlock Irrigation District
UCAN
United American Energy
Watson Cogeneration Company

The ***ER 96*** Staff management team was led by Daniel Nix, Terry O'Brien, and Karen Griffin. The other team members included Thom Kelly, Mike Jaske, Greg Newhouse, Chuck Najarian, Marwan Masri, Linda Kelly, Ross Miller, Tim Tutt, Mike Messenger, and Dave Abelson.

A large group of Energy Commission staff contributed directly to the authorship of the ***1996 Electricity Report***. The Committee recognizes and appreciates the work undertaken by a host of talented individuals, with special recognition to: Jonathan Blees for his counsel, authorship of several chapters of this report, and extensive editing; Rosella Shapiro for her tireless efforts on numerous chapters; Celia Howell for her insightful editing and writing; Tom Tanton for his work on the RD&D chapter; Dan Nix for his support and that of the Energy Information and Analysis Division; Mike Jaske and Ken Goeke for their work on consumer choice and retail service issues; Melinda Merritt, Lorenzo Kristov, Hebert Diaz-Flores, and Melissa Jones for their work on information issues; Carol J. Hurlock, Ruben Tavares, and Linda Kelly for their work on issues pertaining to publicly-owned utilities; Greg Newhouse, Cynthia Praul, Matt Layton, Rick Buell, Lynn Marshall, and Ross Miller for their work on environmental issues; Tim Tutt and Mike Messenger for their work on energy efficiency issues; Mike DeAngelis for his work on RD&D issues; Richard Grix, Bob Grow, Al Alvarado, Ben Arikawa, Philippe Auclair, Melissa Jones, Brandt Stevens, Lorenzo Kristov, Jon D. Edwards, and Joseph Diamond for their work on the economic effects of restructuring; and Ross Miller, Jim Hoffsis, Linda Kelly, Constance Leni, Carol J. Hurlock, Donna Stone, Ron Wetherall, Jerry Green, Terry Ewing, Manuel Ramirez, Jennifer Garland, Mary Ann Miller, Michael Magaletti, and Calvin Wire for their work on supply-side resource assessments and the technical appendices. The Committee also appreciates the efforts of Ken Goeke, Tom Gorin, Mike Jaske, and Richard Rohrer for the preparation of staff's demand forecast. Finally, the Committee thanks Janet Gregory and Cathy Graber for their work in scheduling meetings and coordinating the Committee's calendars.

The Committee and management team are especially grateful to Project Secretary Barbara Crume and to Phillis Soresi-Tam, Kelleen Harter, Lynette Esternon, and Karen Shimada for their help in preparing and distributing notices, orders, reports, testimony, and other documents to all participants.

Finally, the Committee thanks the following individual staff for their contributions:

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INTRODUCTION AND EXECUTIVE SUMMARY

In the ***1994 Electricity Report*** (***ER 94***) the California Energy Commission (Energy Commission) strongly supported the restructuring of the state's electricity industry from a system of regulated monopolies to a competitive market. We argued that only by unleashing the forces of competition would the state enjoy "societal economic efficiency" -- the greatest value for consumers at the lowest possible price. We encouraged efforts to transform monopoly electricity generation into a free market, and to transfer control of monopoly transmission lines to a central coordinating entity that would grant nondiscriminatory access to all sellers and buyers. We urged that other areas of the electricity business be opened to competition, and that even those aspects that remain under monopoly control be injected with elements of choice. We said that restructuring should not cause environmental damage and we proposed new market-based mechanisms of environmental regulation. Finally, we discussed actions necessary to preserve California's important policies of energy efficiency, renewable power development, and research, development, and demonstration (RD&D) of advanced electricity technologies.

In a matter of months, major steps toward the vision we described in ***ER 94*** will become a reality. Debates about the basic outlines of a competitive system are generally over, and thus in the ***1996 Electricity Report (ER 96)*** we turn to an examination of implementation details, to new issues raised in the past two years, and to issues that remain unresolved. Our fundamental goals remain the same: to ensure that California's electricity system is as economically efficient as possible, and that the state's public policies are achieved. This report examines the extent to which the restructured system achieves those goals, and it offers suggestions for improvements where they are needed.

Chapter 1, An Overview of the Restructured Electricity System, describes the key building blocks of the restructured system, established primarily by the recent state legislation known as Assembly Bill 1890 (AB 1890):

- An Independent System Operator (ISO) to operate the transmission system and provide access to all buyers and sellers (The Glossary of Abbreviations and the Glossary of Restructuring Definitions list and define key terms such as ISO.)
- A Power Exchange (PX) to provide a bid-based spot market for power
- Consumers choosing who provides their power and who provides metering and billing services
- The continuation of the current monopoly utility ownership of the transmission and distribution wires, subject to ISO control of the transmission system
- Bringing competition to some customer service activities (such as metering and billing)
- Collection of the "competition transition charge" (CTC) for past utility investments that turn out to be uneconomic in a competitive market, and for other costs such as utility contracts with independent power producers

Chapter 1 also outlines the ways in which AB 1890 provides for energy efficiency, RD&D, and renewable power programs to be continued during the first four years of restructuring. (Most of AB 1890’s changes are to be implemented during the period from January 1, 1998 to December 31, 2001. That four-year period, which for some matters is extended to March 31, 2002, is often referred to as the “transition period.”)

Bringing competition into electricity generation is necessary for economic efficiency, but it is not sufficient. In order for the state to fully enjoy the potential benefits of restructuring, there must be "meaningful consumer choice" at all levels of the electricity system. **Chapter 2, Meaningful Consumer Choice for Retail Electricity Services**, describes the concept of meaningful consumer choice and sets forth five key principles to implement it.

Chapters 3 through 8 discuss in detail the major effects of restructuring.

Chapter 3, Economic Effects of Restructuring, begins by examining the likely impacts of restructuring on several different aspects of consumers' electricity bills. It then addresses a key equity issue **--** will small consumers see substantial benefits from restructuring **--** and suggests ways to ensure that they will. Next, in order to make transmission pricing more economically efficient it recommends changes in charges for transmission services. Finally, it discusses how undue market power could result in unfair pricing and describes steps to support a truly competitive playing field.

Under AB 1890 the responsibility for the reliability of California's electricity system will change dramatically. **Chapter 4, Effects of Restructuring on Reliability**, explains the changes. It also concludes that protections in the legislation make it unlikely that reliability of the generation, transmission, or distribution systems will suffer. Chapter 4 also examines whether the economic incentives of a competitive market will be sufficient to cause enough new power plants to be built in the future. It concludes that the incentives will be adequate if short-term prices rise to high levels; however, because the price rises need to be only for short periods of time in order to create adequate incentives, consumer bills should not go up substantially.

Chapter 5, Environmental Effects of Restructuring, discusses the uncertainties that make reliable assessment of environmental impacts difficult at this time. Focusing on air quality, the chapter states that to date there is no evidence of any circumstances that will result in either significant unavoidable adverse impacts or significant environmental benefits. The Energy Commission will continue to monitor the environmental impacts associated with restructuring and to work closely with stakeholders and other governmental agencies. The chapter also explains why continuing the recent trend towards more market-based environmental regulation is both good economics and good for the environment, and it states that progress should continue to be made here regardless of the course of restructuring.

In recent years the state's efforts to encourage energy efficiency have also begun to rely more on market-based strategies. **Chapter 6, Energy Efficiency**, explains why the state should turn away from subsidy-based programs and towards "market transformation" programs designed to produce sustainable changes in available products and services and in consumer behavior.

For the past two decades, California has led the nation in RD&D for advanced energy technologies. In the transition to a more competitive electricity system, RD&D efforts are likely to fade without government support through collaboration involving utilities, the public, and the private sector. In anticipation of competition, utility RD&D budgets have declined. While the decline may be temporary, the long term impact of restructuring on overall RD&D energy efforts should be monitored closely. **Chapter 7, Research, Development and Demonstration**, sets forth key RD&D principles that will ensure the state's electricity consumers will benefit from a cost-effective, environmentally-sound, safe, and reliable energy system.

One of California's key energy policies is that the electricity system consumer should have a diversity of generation types and fuels from which to choose, in order to provide security against supply disruptions and economic dislocation. **Chapter 8, Risk Management and Diversity**, explains the components of a diversity policy and recommends state actions to ensure that appropriate levels of diversity are obtainable, consistent with principles of economic efficiency.

Because of recent technological advances, small-scale, widely-dispersed generators are becoming economically competitive with their large, central-station power plant cousins; they may offer environmental advantages as well. **Chapter 9, Distributed Energy Resources**, discusses the potential for those generators to provide a significant portion of the state's electricity in the future.

With new and shifting roles in the electricity system, many market participants will need new types of information**. Chapter 10, Information Needs in a Competitive Energy Services Marketplace**, outlines what information will be needed by whom and offers some suggestions about how information should be obtained and provided. It also discusses the delicate balance among market participants' legitimate needs for information, appropriate proprietary rights to information, and confidentiality concerns.

Although restructuring will affect all utilities in the state, it will affect publicly-owned utilities (POUs) in some ways differently than it will affect investor-owned utilities. **Chapter 11, Publicly-Owned Utilities**, discusses the similarities and differences, and the unique opportunities for POUs in a competitive market. be a simple matter.

Chapter 12, The Need for New Power Plants, contains assessments of supply and demand trends in electricity. It also establishes the criteria that the Energy Commission will use in determining whether new power plants are "needed." State law provides that the Commission cannot license a new power plant unless the Commission determines it is needed; the rule protects electricity consumers from having to pay for plants that are unnecessary. In a competitive market, however, consumers will not provide the financial guarantees they did in the old regulated monopoly system; instead, private investors will bear the risk that a plant will turn out to be not needed. Therefore, the chapter concludes, there is no need for stringent need conformance criteria and that demonstrating conformance with the Integrated Assessment of Need (IAN) should

Chapter 1

AN OVERVIEW OF THE RESTRUCTURED ELECTRICITY SYSTEM

Introduction

In the ***1994 Electricity Report (ER 94)*** the California Energy Commission (Energy Commission) wrote "the electricity industry in California is about to undergo its most radical changes in the last 50 years . . . within five years, and probably less, major elements of this industry will be transformed by the forces of competition." Those "radical changes" will be upon us sooner than anyone had imagined when ***ER 94*** was published. On January 1, 1998, the first fully competitive electricity generation market in the country will begin operation. This chapter describes the major features of that market. The discussion applies primarily to the state's private, investor-owned utilities (IOUs); publicly-owned utilities (POUs) are discussed in the concluding section of this chapter.

The Present System

Under the current system of regulated, monopoly electric utilities, a "regulatory compact" gives the IOUs certain rights and imposes on them certain obligations. The utilities are given a legal monopoly called a “franchise” in their "service areas." [There are seven IOUs in California; three of them: Pacific Gas and Electric (PG&E), Southern California Edison (Edison), and San Diego Gas and Electric (SDG&E), are by far the largest and, our discussion of the IOUs focuses on them.] The monopoly franchise extends to all of the following aspects of the utility business:

- Generation -- Producing power in power plants or purchasing it from other generators.

- Transmission -- Carrying the power from power plants over high-voltage transmission lines to load centers.

- Distribution -- Delivering the power to customers at reduced voltages, through substations and distribution lines.

- Customer Service -- Activities here include matters such as metering and billing. Customer service has traditionally been considered part of the distribution function.

In exchange for being granted a monopoly franchise, the utilities must serve all customers in their geographic service area under terms of service and rates set by the California Public Utilities Commission (CPUC). [The Federal Energy Regulatory Commission (FERC) sets rates for wholesale power sales and high-voltage transmission.] IOUs have a constitutional right to have rates set at a level that is sufficient, but no more than necessary, to provide a reasonable opportunity to recover the costs the IOUs have prudently incurred in serving customers, and to earn a fair profit on and return of the investments they have made in capital facilities such as power plants and transmission lines. The profits go to pay dividends to utility stockholders and interest to utility bondholders.

Although the CPUC separately calculates the costs and profits for all four aspects of utility service, most customers currently pay only one all-inclusive rate. Large industrial and commercial customers may have their charges separated into various categories.

When the utility system was instituted, approximately 100 years ago, there were sound reasons of economic and technological efficiency to have one company control generation, transmission, distribution, and customer service in a defined geographic area. Both federal and state laws were enacted to provide those benefits by establishing the monopoly system, and to protect consumers by regulating rates and services. During the past two decades, however, advances in generation and metering technology and changes in federal and state law have eroded the justification for the monopoly in generation and customer service activities, and for the "bundling" of generation, transmission, distribution, and customer service in one entity. By the early-1990s it was apparent that the time was ripe to restructure the electricity industry, as the natural gas industry had been restructured in the mid-1980s.

The Restructured System

As a result of CPUC and FERC decisions in 1995, 1996, and 1997, and landmark state legislation, referred to as AB 1890, that was enacted in September 1996 and that formalized the new competitive market, California's electric system will look quite different on January 1, 1998, than it has looked. Some aspects of restructuring will not be complete until the end of the year 2001 (and in a few cases longer); for that reason, the 1998-2001 period is often referred to as the "transition period."

Unbundling

Utilities will no longer control generation, transmission, distribution, and customer service as one integrated company. Although the IOUs will still be permitted to engage in all types of businesses, their control will be functionally "unbundled" as if there were four separate companies. The functions will be performed partly by the utility company, partly through competitive businesses, and partly by new regulated entities created by AB 1890.

Generation

The generation aspect of the utility business will generally become competitive and operate under free-market principles. Anyone can own and operate a power plant and sell power to any customer. Sellers and buyers can participate in a centrally-coordinated market, in which prices are set by daily bids (the Power Exchange, or PX), or they can enter into longer-term "direct access" contracts between individual buyers and sellers. Whether in the PX or through a direct-access market, customers may make individual arrangements with suppliers or they may "aggregate" in order to increase their negotiating power. Customers do not need to participate directly in the PX or in direct access; they may choose to stay with their existing utility. All generators and consumers connected to the ISO-controlled grid (see following discussion) will have to comply with the ISO's rules.

Generators and customers participating in the PX will submit bids for the price at which they are willing, respectively, to sell and buy power. (Customers may also, in the case of "demand bids," indicate the price at which they are <u>not</u> willing to buy. A demand bid may be expressed as a price above which the customer will purchase no more power, or as a price at which the customer will reduce his or her power consumption.) When there is enough supply to meet demand, the bid of the most expensive generator necessary to meet demand will set the market-clearing price (MCP), which will then be paid by all buyers to all generators. When supply is inadequate to meet demand, the MCP will be set by the lowest demand bid necessary to curtail a customer's energy use and thus restore the balance between supply and demand.

No longer restricted to buying power only from the local monopoly utility company, customers will be able to compare one deal to another and choose the one that meets their preferences. It is possible that packages of power and other services (metering and billing, conservation devices, even cable TV and telephone) will be offered. Customers will also have the opportunity to get customized products and services; for example, some customers may not need high levels of reliability, while others may need exceptional reliability. Some customers may be able to shift the timing of their electricity use to take advantage of lower prices during off-peak periods. AB 1890 contains customer-protection provisions that can help consumers guard against untrustworthy sales practices.

Prices for generation will generally be set in the free market, and power plant owners (both utilities and others) will have their profits go up and down accordingly. Certain plants, such as nuclear facilities and those critical for reliability, will have specialized pricing arrangements.

The IOUs currently own most power plants in the state. Because of that, even when generation is opened to competition the utilities may be able to dominate the market and set generation prices at an artificially high level. In order to prevent the utilities from exercising undue market power, the CPUC has required PG&E and Edison to divest half of their power plants that operate with fossil fuels, and, during the transition period, to sell and buy all their power through the PX. In addition, FERC will not give final approval to California's restructured system unless the agency is satisfied that market power is at acceptable levels.

Transmission

The IOUs will give control, but not ownership, of their transmission lines to a central operator called the Independent System Operator (ISO)[1]. The ISO will be responsible for ensuring that all power sellers have equal access to the transmission grid, and for ensuring the reliability of the system. The utilities' transmission revenues and profits will still be regulated, but the prices that generators pay for access to the transmission system will be different than they are now. Transmission pricing is discussed in Chapter 3, Economic Effects of Restructuring, and Chapter 4, Effects of Restructuring on Reliability.

Distribution

Distribution will stay much as it is today. Each utility will still own and operate the local distribution system as a monopoly, and distribution rates will be regulated by the CPUC. However, ratesetting will be more market-oriented; "Performance-Based Ratemaking" (PBR) will set a target revenue and profit level but the utilities will have more flexibility to manage costs and services.

Customer Service

The metering and billing functions will be unbundled from the distribution function and opened up to competition. Utilities can still provide services in this area, but they will do so in competition with others and with free-market pricing and profits.

Stranded Costs and the Competition Transition Charge

Under the current monopoly system the CPUC implements a ratemaking method that provides revenues sufficient for the IOUs to recover the costs they prudently incur in serving customers and to earn a reasonable profit on and repayment of their capital investments. (Much of the capital invested in a plant is for initial construction; there may be additional capital investments over time.) The repayment of the capital investments is paid back, or amortized, over a long period of time, typically 30 years. For example, if a utility has invested $100 million in a power plant, part of each customer's rates goes to pay a reasonable profit each year (e.g., 10 percent of the unamortized capital investment) and part goes to pay back the initial $100 million investment over time (e.g., $3.33 million per year over 30 years). In the restructured market, however, the revenues that power plants receive will no longer be set by regulators. Instead, the plants must compete in the open market and will receive only as much revenue as customers are willing to pay (and for some plants, what the ISO pays for reliability contracts and ancillary services).

The utilities still have numerous power plants for which the capital investments have not been fully repaid; generally those plants are less than 30 years old, the typical amortization period. Revenues received in the competitive market may not be adequate to provide reasonable(or any) profits or repayment of the investment. Such investments are called "stranded costs.” Because the utilities' investments were made as part of the regulatory compact and were approved by state regulators, the CPUC and the Legislature have determined that it would be unfair to change the rules of the compact in a way that would penalize the utility stockholders and bondholders for past investments.

Therefore, to the extent that a utility has stranded costs, its customers will see on their bills a separate "competition transition charge" (CTC) that is designed to pay off the stranded costs in the 1998 - 2001 period. Each customer will pay the CTC for that customer's distribution utility, even if the customer has chosen a different entity to be the customer’s generation supplier. In addition to stranded power plant costs, the CTC will also pay for certain other costs, specified in AB 1890, that may not be recoverable through competitive power sales revenues, such as payments under long-term contracts with above-market costs with independent power generators (sometimes referred to as Qualifying Facilities or QFs) and expenses for retraining employees displaced as a result of restructuring. About 80 percent of IOU stranded costs are comprised of nuclear generation capital costs and QF contracts. For purposes of paying off power plant investments, the CTC ends in 2001; if there are still stranded costs of utility-owned power plants remaining at that time, the utilities will not recover them. (CTC recovery will continue until the other types of stranded costs are recovered.) If the old system were still in place, ratepayers would be paying those costs, albeit at a lower rate, for a substantially longer time. The goal of establishing the CTC is to provide the benefits of competitive markets quickly while still allowing the utilities a reasonable opportunity to recover stranded costs.

Public Interest Programs

Under the current system the CPUC has directed the IOUs to spend ratepayer funds for several programs the Legislature has declared to be in the public interest:

- Energy efficiency
- Research, development, and demonstration (RD&D)
- Renewable power
- Low-income rate assistance [formerly known as LIRA, the program is now called the California Alternative Rate for Energy (CARE)]

Beginning in 1998, the utilities will no longer be mandated to carry out such programs, nor are they likely to have an incentive to do so. Because such programs have public benefits, however, AB 1890 requires, at least during the 1998 - 2001 period, that all customers pay a separate "public goods charge" on their bills.. The CPUC and a newly-created, independent board will oversee implementation of the energy efficiency programs, and the CPUC will continue to oversee CARE; subject to legislative approval, the Energy Commission will oversee the renewables programs and almost all of the RD&D programs. Chapters 6, Energy Efficiency; 7, Research, Development, and Demonstration; and 8, Risk Management and Diversity discuss energy efficiency, RD&D, and renewable power in considerable detail. With minor variations, the annual collections for the three major IOUs will be $228 million for energy efficiency, $62.5 million for RD&D, $109.5 million for renewables, and $102 million for CARE.

What Electricity Bills Will Look Like

Most customers now receive a one-line electricity bill. Because of the functional unbundling of utility service, the public interest programs authorized by AB 1890, and the CTC, beginning in June 1998 most bills will have several separate categories. The CPUC has ruled that IOU bills will contain:

- Power Generation (the cost of power obtained either from the PX or from a direct access provider
- Transmission Access
- Distribution Service
- Public Interest Programs
- Competitive Transition Charge

As a result, customers will have a greater understanding of how their electricity dollars are spent and a greater ability to affect their expenses.

Rate Reduction and Rate Freeze

It is widely believed that small customers, who have less economic clout and less time and resources to "shop around" for generation suppliers, will not see as many benefits from restructuring as larger customers. The Legislature wanted to ensure some benefits for the smaller customers; thus, AB 1890 directs that the IOUs' residential and small commercial customers ("small" meaning less than 20 kilowatts of peak demand) will have a 10 percent rate cut beginning in 1998.

AB 1890 also requires that rates for all other customers be frozen at their June 1996 levels from 1998 through 2001. However, because of market trends and the introduction of more efficient power plants, IOU rates probably would fall during that period even without AB 1890. Thus as a result of the legislation, rates will probably be ***higher*** than they would have been for large customers for the next several years. (The 10 percent reduction for ***small*** customers may be larger than the rate decline that would have occurred without AB 1890.) The extra revenue from large customers will not be a windfall for the utilities, though; it will be used to pay off stranded costs. In effect, ratepayers will pay more for a few years in order to quickly pay off stranded costs for IOU-owned power plants , in return for being free of the obligation to pay those stranded costs after 2001. Rather than a transition period of a dozen years or more which would otherwise be necessary to pay off the stranded costs, accelerated payment of the stranded costs will allow California to move to a competitive system with free-market pricing in around four years.

To help finance the rate reduction, AB 1890 authorizes the IOUs to issue “rate reduction bonds.” The proceeds of the bond sales will be used to pay off a portion of the utilities’ stranded costs (costs that would otherwise be paid by the CTC), with the interest and principal on the bonds to be paid by ratepayers. The rate reduction bonds will help finance the 10 percent rate reduction in two ways. First, the bonds will lower the carrying costs of a portion of the utilities’ stranded investments: the bonds will have an interest rate of around 7.5 percent, while the IOUs’ return on capital investments (which the CTC would have to pay) averages around 9.7 percent. Second, the bonds will spread out recovery of stranded costs: instead of ratepayers paying stranded costs over four years through the CTC alone, some of the stranded costs will be paid through the bonds, which have a repayment period of 10 years. (As with a home mortgage, a longer repayment period means smaller payments each year, although the total payments may be higher.)

Because the bonds will finance the 10 percent rate reduction for residential and small commercial customers, those customers will pay off the bonds. There will be a separate charge for the bonds called the Fixed Transition Account (FTA). The total bond payments are about $2.742 billion for PG&E, $2.301 billion for Edison, and $0.630 billion for SDG&E. The net savings for ratepayers **--** the savings due to the mandatory 10 percent rate reduction, minus the cost of paying off the bonds **--** will be about $439 million, $374 million, and $96 million respectively.

Much of the benefit of the bonds relies on a recent ruling from the Internal Revenue Service that will allow the utilities to defer tax payments on property covered by the CTC. Assuming a 10 percent discount rate, $341 million of PG&E’s net $439 million savings, $291 of Edison’s net $374 million savings, and $77 million of SDG&E’s net $96 million savings are due to the favorable tax treatment.

Publicly-Owned Utilities

California's POUs provide electric service to approximately one-fourth of the state's population. Some POUs have power plants, some have transmission lines, and some have only distribution systems. Some are large utilities serving many customers in a fairly large area; some have only a few hundred customers. Although the sweeping changes instituted by AB 1890 and the CPUC do not apply to the POUs to the same extent that they do to the IOUs, the POUs will also see substantial changes.

AB 1890 states the Legislature's intention that the state's POUs voluntarily give control of their transmission facilities to the ISO, as the IOUs are required to do. The statute guarantees POU representation on the ISO board, and it contains a strong incentive for the POUs to join; a POU cannot implement a CTC for its stranded costs unless the utility gives the ISO control over its transmission facilities. Similarly, although AB 1890 does not require POUs to institute direct access for their customers, the statute allows POUs to institute a CTC only if they do allow direct access. If direct access is allowed, POUs may act as an aggregator for their customers.

As it does for the IOUs, AB 1890 requires each POU to establish a public goods charge, which must be no lower than the smallest amount spent by the three major IOUs, on a percentage of revenue basis, for public interest programs. However, in contrast to the IOU requirements, which spell out specific dollar amounts to be spent on each public interest program, AB 1890's POU provisions leave each POU with the discretion to allocate the funds among programs.

AB 1890's rate reduction and rate freeze provisions do not apply to the POUs. Ratesetting, along with most of the other important aspects of utility operations, will remain the responsibility of each POU board. Chapter 11, Publicly-Owned Utilities, discusses POU restructuring issues in more detail.

What *ER 96* Does

The theme of ***ER 94*** was the necessity for substantial change in the electricity system in order to obtain “societal economic efficiency” **--** the greatest value in electricity service for the least amount of consumer dollars. In the ***1996 Electricity Report (ER 96)***, although we continue to stress the need for economic efficiency, our focus has shifted from big picture items such as “should there be an ISO?” to smaller details and to the myriad issues that arise in any major undertaking. The rest of ***ER 96*** expands on some of the discussions in this chapter, identifies potential problems and new opportunities in various aspects of restructuring, and recommends actions to ensure that the benefits of restructuring are as large, and as widely enjoyed, as possible.

Endnotes

1. A five-person “Oversight Board,” with members appointed by the Governor, the Speaker of the Assembly, and the Senate Rules Committee, oversees the ISO and PX and appoints the members of their governing boards.

Chapter 2

MEANINGFUL CONSUMER CHOICE FOR RETAIL ELECTRICITY SERVICES

Introduction

In December 1995, the California Public Utilities Commission (CPUC) reaffirmed its intent to rely on competitive markets with "the broadest possible array of choice in which the former ratepayer can function as an intelligent self-interested customer." The CPUC correctly emphasized that "in the absence of well under-stood and easily exercised consumer options, the genius of competition is thwarted." Those CPUC statements resonate with the Energy Commission's view that electricity competition will provide substantial benefits for a broad spectrum of California citizens only if policymakers address restructuring with the goal of giving retail consumers meaningful choice in all aspects of their electricity service.

The concept of "meaningful consumer choice" signifies a retail marketplace in which consumers have reliable information about and are able to purchase, from a variety of suppliers, electricity and related services differentiated on the basis of reliability, quality, and other features -- in contrast to traditional utility-supplied electricity service, which gives customers little or no choice about what services they receive or who supplies them. Consumers need an electric services marketplace that can tailor services to their specific requirements, and, given recent economic and technological developments, there is no reason why they should not get what they want at an affordable price. "Meaningful consumer choice" offers the needed conceptual framework to guide policy makers in their efforts to affect the course of restructuring through and after the transition period so as to achieve the greatest, and most fairly distributed, benefits to California electricity consumers.

Principles of Meaningful Consumer Choice

Policymakers should strive to implement five key principles. We first list the principles, then elaborate on them and identify potential problems.

Principle 1: Empower Consumers to Make Value-Enhancing Choices.
Consumers should have the means available to them to:

- Evaluate alternatives
- Make choices that best satisfy their needs
- Determine whether chosen alternatives provide benefits as promised
- Seek recourse in the event of a failure of services to perform as anticipated

Principle 2: Develop a Marketplace for Consumer-Oriented Energy Services.
The new marketplace should stimulate and reward innovation (for both competitive and monopoly suppliers) so that consumers are offered diverse services that are tailored to fit their needs, and government should foster such a market.

Principle 3: Ensure Fair and Efficient Pricing.

- Competitively provided services should be priced by competitive forces, rather than by individual persons or entities asserting market power.

- Rate structures for monopoly services should encourage economic efficiency.

- Full costs of providing a service should be paid by the transacting parties, not be imposed on other parties or on society at large.

Principle 4: Ensure Protection of Low-Income Consumers.
Restructuring policies should maintain the state's commitment to the broadly shared social goals currently implemented in "lifeline" rates. However, the rates themselves should be abandoned in favor of a more economically efficient total bill subsidy.

Principle 5: Ensure Transparency of All Subsidies.
If policymakers wish to impose a tax or to increase the price of any service to subsidize public programs or other policy objectives, the programs should be clearly targeted to meet their objectives efficiently and their costs should be fully disclosed to the public.

Principle 1: Empower Consumers to Make Value-Enhancing Choices

Whatever final shape the restructured industry takes, consumers will face new choices about their energy purchases. An informed consumer is an essential requirement for economic efficiency. If consumers are empowered with the ability to make informed decisions, retail market power abuses and informational transaction costs will be minimized, consumers will benefit by knowing they can obtain the type and level of service they want, and providers will benefit by knowing that competence and innovation in their services will be rewarded. To those ends, government has an important role in ensuring that:

- Consumers have adequate information
- Suppliers are trustworthy

Given the technical complexity of electric services, consumers will need to have reliable information about services, products, and useful tools for assessing the information when making choices. That is a difficult task, because most residential and small commercial customers will have little expertise. Time-consuming cost comparisons will likely discourage many small customers from participating in the competitive marketplace, and at least in the near term the market -- which has no tradition of consumer choice -- is less likely to target small customers for marketing efforts. Moreover, energy service providers will want to make their own offerings look best, and they may have no desire to facilitate meaningful comparisons between theirs and the offerings of other providers. (Consider the common complaints regarding long-distance telephone service by consumers who have been confronted with alternative calling plans that cannot be meaningfully compared.)

Consumers also need assurances that the companies they rely on are trustworthy. There are registration requirements in Assembly Bill 1890 (AB 1890) and in recent CPUC Decisions for energy service providers, and AB 1890 also establishes market rules for information disclosure and for switching a customer's energy service provider. Although necessary, those requirements may not be enough to assure residential and small commercial customers that they are dealing with reputable firms and are being provided trustworthy information. A perceived lack of trustworthy information and a desire to avoid making an incorrect decision may lead consumers to choose "not to choose"; that is, they may tend to remain bundled service customers of the utility distribution company because that is service to which they are accustomed and because they believe they lack trustworthy information about alternatives.

Energy service providers should increase the trustworthiness of their offerings by self-monitoring and by developing voluntary certification programs that provide evidence of financial soundness, such as proof of good standing in company associations, information concerning the business purpose of the entity, and the name, title, and telephone number of a customer service representative. In addition, certified energy service providers should abide by a Code of Conduct that would require them to provide customers with:

- Accurate information on prices, quality, service record, and terms of service

- Real choices involving tradeoffs of quality or quantity versus costs

- A neutral, prompt, and no- or low-cost forum for resolving customer complaints

- The ability to participate in regulatory oversight of the industry

The CPUC, which has the responsibility for registration of energy service providers, hasthe authority to suspend registration for violations of fair business practices, but ongoing governmental regulation after the transition period should not be necessary if the industry is willing to police itself.

Empowering consumers -- with reliable information, useful tools for making choices, means of verification, and access to a fair mechanism for recourse when dissatisfied -- increases economic efficiency by better matching products and services to customers' real needs. Energy service providers that are able to identify needs and offer services that best fit those needs will be successful in the marketplace, while less competent or less legitimate firms will be weeded out.

Principle 2: Develop a Marketplace for Consumer-Oriented Energy Services

Creating genuine value for individual consumers is crucial to meaningful consumer choice. Because customers have different end-use desires and budgets, the new marketplace must encourage and reward innovative and efficient suppliers of a broad range of customized products and services.

Industry restructuring must ensure that competent, innovative firms are able to enter the market and capture the rewards of good performance. Barriers to entry, such as undue market power and lack of access to information, must be reduced; firms gaining a competitive advantage through innovation and entrepreneurial ability must be allowed to reap the profits.

Many industry experts believe that the basic electric commodity, while it may still be the core of a provider's business, will in the long run offer a relatively low profit margin, as was seen in the natural gas industry. Energy service providers will have to develop enhancements to the basic commodity in order to be more successful in the restructured marketplace. One industry expert who advises electric utilities in positioning themselves in the competitive marketplace offers the following list of suggestions for utilities to consider, both to expand profit margins in their core electric commodity business and to develop new sources of earnings outside of the core:

- Rates: time-of-use rates, real-time pricing, curtailable rates, fixed and variable pricing, variable term contracts

- Load management: thermal storage, direct and customer controlled load management systems, standby generation, distributed generation, hot water timers

- Electrotechnologies: geothermal heat pumps, electric vehicles, electric lawn mowers, wood curing, paint drying, biomedical waste remediation, glue drying, ink curing, ozone-based paper bleaching

- Energy management services: insulation, heating and air conditioning, lighting, refrigeration, energy management controls, financing, installation contracting, shared savings

- Power services: power conditioning, standby generation, operation and maintenance, power factor correction, emergency generation, cogeneration, distributed generation, mobile generation

- Energy information services: real-time pricing, remote meter reading, disaggregated billing, remote service, fault location, remote equipment diagnostics and operation, joint meter reading, on-line billing, remote power quality monitoring, direct load control

- Other services: equipment financing and leasing, economic development, energy engineering and consulting, district heating systems, and electricity brokerage services

A single energy service provider might offer several “packages” of services targeted to various consumer segments, introducing and withdrawing them as technologies and customer requirements change.

Another key aspect of Principle 2 is the unbundling of electricity service. A bundled electricity service -- essentially the same for all consumers and provided by a single entity -- is necessary for those consumers who want to continue with "plain vanilla" service from their traditional utility. But for a truly efficient market there must be unbundling of the four functional elements of utility service: generation, transmission, distribution, and customer service. Some participants in the restructuring debate wanted all non-generation and non-transmission functions to remain under the control of the local utility distribution company (UDC). However, if utilities’ business and customer service activities were lumped into the distribution function (or arbitrarily cost-allocated across generation, transmission, and distribution) the line between natural monopoly and competitive market services would remain too fuzzy to allow a logical, systematic approach to important questions about metering, billing, and other revenue cycle services. All customers should have access to a wide range of firms offering those services in creative, low-cost ways; all services for which there is no longer a monopoly justification -- not just generation -- should be opened to competition.

The CPUC recently ruled that generation, transmission, distribution, and a portion of customer service will be unbundled for the IOUs. Beginning in 1998,each customer will have three billing options, depending on the choice of supplier:

1) A power bill from the supplier and a bill for other services from the UDC
2) A consolidated bill from the power supplier
3) A consolidated bill from the UDC

In addition, in 1998 large (over 20 kW) customers, and in 1999 all customers, can obtain metering service from any entity. Those are two major steps in achieving meaningful consumer choice.

In recent months stakeholder groups have undertaken major efforts to implement the CPUC’s important policy decisions. For example, the Scheduling Coordinator User Group is providing evaluation on that new industry function and the Metering and Data Access Working Group (MADAWG) is developing rules for collection, validation, and distribution of metering data. Efforts like these are essential if competitive industries are to develop their own processes of change rather than rely on governmental decisions.

Principle 3: Ensure Fair and Efficient Pricing

Pricing in the new electricity marketplace should be based on the following three elements:

- Competitively provided services should be priced by competitive forces rather than by players asserting undue market power.

- Rates for monopoly services should encourage economic efficiency.

- The full societal costs of providing a service, whether provided competitively or by a monopoly, should be paid by the transacting parties, not imposed on other parties or on society at large.

Economic theory indicates that competition will force producers to price services near marginal costs. However, the degree to which this is accomplished in practice depends on the number of service providers in the marketplace and the ability of new firms to enter the market.

Participants with undue market power can raise prices well above marginal costs. Inflated prices are both unfair, because they transfer income from consumers to firms with no corresponding return of value, and inefficient, because society enjoys less of the service than would be affordable at competitive prices. The CPUC and POU boards should take two steps as soon as possible to bring efficient pricing principles to competitively-priced generation costs and to monopoly-service transmission and distribution costs.

First, while opening up power generation to competition is critical, it is not the only aspect of bringing efficient pricing principles to that sector of the market. Electricity costs vary substantially from hour to hour during the day (and from season to season) because there is a wide variation in power plant efficiency. In times of high demand, most of the system's power plants must run, including the least efficient (and thus most expensive) plants; in times of low demand only the most efficient (and thus least expensive) plants need to run.
Price signals based on hourly energy costs would provide consumers with the option to substitute consumption during low-cost periods for consumption during high-cost periods. As technology develops, all consumers will be better able to take advantage of hourly price signals. Soon appliance manufacturers may produce electric heating, cooling, refrigeration, water heating, and other equipment that can be cycled on and off. Industrial customers may be able to run equipment with high energy use at low-rate times. But for those actions to produce cost savings, the customers must have "real-time" (also called "interval") meters that record and charge for consumption on an hourly basis. Large IOU customers will be required to have interval meters in 1999; all customers should have access to the necessary metering equipment as soon as possible.

Second, for those service components that remain with the monopoly transmission and distribution companies, efficient pricing means that rates should reflect the cost of service and that the subsidies in current rates be eliminated. The rate freeze in AB 1890 allows for a transition period in which the inefficiencies in current rate designs can be exposed and solutions proposed so that after the transition, monopoly services can be priced efficiently. Efficient rate design should reflect the high fixed cost of existing systems and the high incremental costs of line extension to new customers, including those in remote locations. Existing inefficiencies in rate design must be examined during the transition period because during this period there is an unequaled opportunity to construct more efficient rates.

Principle 4: Ensure Protection of Low-Income Consumers

The Legislature has detemined it is appropriate to subsidize low income households with an essential basic level of electric service if they cannot afford to pay the full cost. The costs facing the low-income population should be subsidized (with an express, non-hidden charge -- see Principle 5) through a small surcharge applied to full-price customers, as provided by AB 1890.

However, as we noted in ***ER 94***, the role of baseline rates should be re-examined and alternatives identified to provide minimum levels of electricity to low-income households. Baseline rates, which allow a certain number of kWh of each customer's electricity use to be priced at an artificially low rate, are incompatible with efficient pricing principles. All customers, including low-income households, should see on their bills the true costs of service, so that they can make economically rational decisions to consume more or less. Low-income customers should not have their costs of service hidden by making their rates artificially low. Rather, all customers should be charged full *rates*, while low-income customers get a subsidy on their total *bill*.

Principle 5: Ensure Transparency of All Subsidies

Surcharges or taxes for public policy energy programs -- energy efficiency, research, development and demonstration (RD&D), renewables, and low-income assistance -- should be "transparent." That is, there should be a well-defined policy objective; an estimated cost of achieving the objective; a designated source of funds to meet the cost; a well-specified program for using the funds to achieve the objective; full disclosure of the costs to those who pay; and procedures for monitoring and evaluating the program.

Transparency is admittedly a rigorous but necessary standard. It should have high priority because there will be significant deviations of prices from direct costs in the industry over the next several years. Problems such as stranded investments, research and development funding, low-income assistance, and others are being dealt with through special charges on electricity bills; if the charges are not transparent then the costs of the programs, and the efficacy of the benefits compared to the costs, cannot be assessed with confidence. In addition, there are large cross-subsidies in the current rate structures; the goal of societal economic efficiency requires that cross-subsidies be eliminated, but the desire by regulators to prevent sudden large increases in energy bills may lead to a gradual phase-out. In all these instances Principle 5 argues for full transparency. To allow hidden subsidies to persist would undermine the entire set of principles of meaningful consumer choice.

Chapter 3

ECONOMIC EFFECTS OF RESTRUCTURING

Introduction

When the Energy Commission first endorsed restructuring it was not possible to estimate its economic effects reliably, because we didn't know how a restructured market would operate. Our support of a competitive market was based on well-established economic theory and on evidence from other markets that have been recently deregulated, such as the natural gas, telephone, and airline industries.

Now more is known about how California's competitive electricity market will work. For more than a year, technical groups have been working out the details of how the Independent System Operator (ISO) and Power Exchange (PX) will function. The Federal Energy Regulatory Commission (FERC) has issued orders and the California Public Utilities Commission (CPUC) has further defined restructuring issues. Armed with that knowledge, and with AB 1890, which establishes ratemaking directions for the 1998 - 2001 time period, we endeavor in this chapter to quantify the impacts of restructuring on consumers. We examine issues of equity, because of concerns that the benefits of a competitive market be accessible to all. Finally, we discuss the potential opportunities for anti-competitive market power to be exerted; the exercise of undue market power needs to be checked if market efficiency is to be maximized and consumers are to reap the benefits of a competitive electricity market.

Pre-Restructuring Trends in Electricity Rates

In order to put economic impacts into context, it is important to understand the trends that were occurring prior to restructuring. In early 1995, the Energy Commission forecast that rates for the three major IOUs would fall in real (inflation-adjusted) terms over the period 1995 to 2000: approximately 3 percent annually for PG&E and Edison, and 1 percent annually for SDG&E. Most of the decline was attributed to falling or ending fixed price payments to Qualifying Facilities (QFs), and the utilities' plans to reduce the costs of nuclear generation, to lay off non-essential employees, and to take other cost-cutting measures in order to position themselves to respond to the changes in the electric industry.

Post-Restructuring Electricity Rates

This section first discusses the effects of AB 1890 on IOU customers and overall rates. [The effect of restructuring on publicly-owned utility (POU) rates is harder to gauge, but, given the force of competition, it is reasonable to expect that POUs will try to keep their rates as low as or lower than the IOUs' rates in order to maintain their customer base.] The section then discusses the specific components of the overall electricity bill.

The Effects of AB 1890 on Overall Rates

The near-term impact of restructuring on IOU rates is known with a great deal of certainty. AB 1890 establishes rate caps for IOU customers, divided into two categories:

- For industrial and large commercial (20 kW or more of maximum peak demand) customers, rates must be capped at their June 1996 levels.

- For residential and small commercial customers, rates must be reduced by 10 percent below their June 1996 levels, starting January 1, 1998.

Both rate caps are scheduled to last until March 31, 2002. (The caps will be removed earlier if the utilities' transition costs have been fully recovered through the Competition Transition Charge (CTC). When transition costs are fully recovered rates should go down because the utilities will no longer have the CTC in their rates.) IOU customers who choose an alternate, direct access supplier will pay the full IOU rate but will receive a credit on the portion of the bill covering power costs; they will pay distribution, CTC and other nonbypassable changes based on what they would have paid had they remained full service customers of their local distribution utility.

AB 1890 also declares the Legislature's intent (but not mandate) that after March 31, 2002, there should be an additional rate reduction of at least 10 percent from June 1996 levels for IOU residential and small commercial customers, for a cumulative rate reduction of 20 percent. Unlike the initial mandated 10 percent rate reduction, however, the intended additional 10 percent reduction will materialize only if utilities can reduce the cost of services. Moreover, the intended additional reduction excludes the costs of electricity procured through the PX and the costs of repaying the "rate reduction bonds" that AB 1890 has authorized to finance the initial 10 percent reduction. Thus, depending on the repayment cost of the rate reduction bonds and the market price of electricity, after the transition period the IOUs' residential and small commercial customers could see total rate reductions of more or less than 20 percent from June 1996 levels; the post-2001 rates could even be higher than the 1989-2001 rates.

Our forecasts of average system rates for all IOU customers, consistent with the rate caps in AB 1890, show a real (inflation-adjusted) decline of about 18 percent over the period 1996 to 2001, equivalent to about 4 percent annually. That is certainly more, but probably not much more, than rates probably would have declined without AB 1890. The primary reason that the difference is not larger is that the benefits of competition will be felt mainly in only part of the overall costs of supplying electricity -- the generation of power in power plants. Power plants will be subject to the rigors of competition, and, as explained later in this chapter, the costs of generating power will decline. Other portions of the customer bill, however, will not have similar changes, so the total reductions in customer bills will probably not be dramatic. For those customers whose bills are more heavily weighted by energy costs, the decline will be greater.

Components of Customer Bills After Restructuring

When restructuring begins, most electricity consumers, including both IOU and POU customers, will see their bills separated into several categories. Generally, the categories will be:

- The price of power itself -- a commodity charge. This is the only price that will be set entirely in a competitive market. The commodity charge will be 1) the average price of power from the PX; 2) the actual hourly costs of the PX for customers choosing that rate option; or 3) for direct access customers, the price negotiated between the customer and the supplier.

- Local utility distribution company (UDC) charges

- The CTC, for those utilities that impose one. CTC collection for IOU generation expenses will end on December 31, 2001, for IOU customers. There is no legislatively-mandated expiration for POU customers.

- The price of transmission services.

- The legislatively mandated "public interest" charge for energy efficiency, renewable energy, low-income assistance, and RD&D programs. (This charge is mandated only through March 31, 2002, for the IOUs. Its expiration date, if any, for the POUs is unclear.)

Other costs, including nuclear decommissioning rate reduction bond repayment, and the administrative costs of the ISO and the PX, will be rolled into one or more of the main components.

How some of these components might be affected by restructuring is discussed further.

Competitive Generation Services

Generation or commodity costs are the portion of the customer bill that will be most affected by competition. The Energy Commission estimates that in the short-term the average cost of power, the commodity cost, will range between 2 to 2.4 cents per kWh depending on a variety of factors, including the price of natural gas. That price is likely to rise into the three cent range after the turn of the century. However, even then the impact of generation competition on total bills will not be large, because generation is only a portion of total costs.

Distribution Rates

Even after restructuring brings competition to the generation part of the electricity system, two major components of the current utility business will remain monopolies: distribution (low-voltage wires and substations) and transmission (high-voltage lines and transformers). Government regulators will continue to set rates for both monopoly services. Today, the integrated utilities have the responsibility for many services beyond the actual distribution wires: metering, data communication, customer database management, billing, collections, and a variety of customer services. The cost of providing those services varies by utility and customer class, but can be up to one-third of the total rate.

A major concern in distribution rates is setting the rates as close to marginal cost as possible. Most costs associated with the distribution system, the low-voltage wires and substations, are incurred at the time of initial construction. Those costs, and most of the ongoing costs of distribution system maintenance, do not vary with how much a customer uses the distribution system -- in other words, the costs are "fixed." (In contrast, much of the costs of generating electricity in power plants are "variable"; a utility's costs of providing power plant service vary substantially with the amount of electricity consumed.) Rates for distribution services should, therefore, have two parts, one part which is constant or "fixed" and the other, smaller portion, which should vary with usage. This is called a "two-part tariff."

Creating a fixed component in the distribution rate increases economic efficiency because it reduces or eliminates subsidies of one customer by other customers. For example, a vacation home that is used infrequently has little electricity usage, but the costs of supplying distribution service to the home need to be recovered even if no electricity is consumed. Without a two-part tariff, the costs of distribution service would be paid for by the variable energy charge of all customers (as they are today), which means that high-use customers pay more of those fixed costs than low-use customers. The fixed electricity costs of the vacation home are thus subsidized by other customers. When true costs are not reflected in rates -- when subsidies are hidden -- consumers' decisions are not economically efficient

Of special concern in the pricing of the distribution system is the cost of line extensions to new buildings. Currently, a large portion of line extension costs are recovered as part of the variable component charged to all customers. That is not reflective of true cost; new customers should be charged the full incremental costs of line extensions. The CPUC should study methods for recovering one-time incremental costs and consider applying them to line extensions.

Competition Transition Charge

The CTC will cover the utilities' "stranded costs" -- the costs of power plant construction, power purchase contracts, and other legislatively designated items that can not be recovered through revenues obtained in the competitive market. The exact magnitude of the CTC will depend on the price of power that the utilities receive in the competitive market. **Table 3-1** shows the IOUs' estimates of the total amount of their stranded costs, based on an assumed MCP of 2.4 cents per kWh. **Table 3-2** shows the estimated stranded costs in 1998 alone.

TABLE 3-1 IOUs' ESTIMATED STRANDED COSTS 1998-2005 NET PRESENT VALUE (1996 $ BILLIONS)		
PG&E	Edison	SDG&E
$11.4	$13.1*	$1.9

* Assumes value of Edison's fossil power plants equals net book value. If value equals zero total stranded costs would be $13.8 billion.

TABLE 3-2
IOUs' ESTIMATED STRANDED COSTS 1998
(1996 $ MILLIONS)

	PG&E		Edison		SDG&E	
Item	Amount	Percent of Total Costs	Amount	Percent of Total Costs	Amount	Percent of Total Costs
QF Contracts	$1,490	na	$1,620	46	$60	10
Nuclear	$1,420	na	$1,350	38	$250	40
Fossil	$190	na	$340	10	$160	26
Fuel and Fuel Purchases	0	na	$150	4	0	0
Inter-utility Contracts	0	na	$40	1	$60	10
Hydro and Geothermal	$580	na	$20	1	0	0
Other	$30	na	$20	1	$90	15
Total Costs	$3,710	na	$3,540	100	$620	100
Less Market Revenue (PG&E only)	$1,180		na		na	
Net Stranded Costs	$2,530		$3,540		$620	

Sums of percents do not equal 100 percent due to rounding.

Source: Edison, PG&E, and SDG&E Applications before the Public Utilities Commission of California, A.96-08-071, October 1996.

Rates for Monopoly Transmission Services

Under the current system, charges for transmission services are based on the fixed and variable costs of providing transmission service and do not appear as a separate part of the bill. Under restructuring, transmission rates will be "unbundled" from the other components of rates and separated into two categories: transmission access and transmission congestion.

First, transmission access charges will be paid by all entities withdrawing power from the ISO grid to recover the fixed capital costs of the utilities that own transmission lines. Second, during every hour when there is congestion on a transmission line -- so much power being transmitted that it is not possible to get the cheapest available power from one location to another -- the ISO will collect “congestion management” fees from those who withdraw power from the grid. That is, those who cause congestion by demanding power will pay the difference between the costs of generation required to serve them and the costs of generation that would be available absent the congestion. The fees will be paid to transmission owners, who will use the revenues to reduce their access charges. If structured appropriately, congestion management fees will send the proper economic signals to users of the transmission network about when it makes economic sense to invest in new transmission facilities, new power plants closer to load centers, or other means to alleviate the congestion.

Users of the transmission grid who wish to avoid the uncertainty of congestion management fees may be able to obtain Transmission Congestion Contracts (TCCs). A TCC is a financial device through which a grid user pays to a transmission owner a one-time charge; in return, the user now holds the rights to receive any congestion management fees.

We are concerned the WEPEX proposal currently being considered by FERC does not provide for TCCs. The proposal states only that TCCs will be made available “when the market demands them.” Uncertain at this time are the criteria that would be used to allocate TCCs, who would pay congestion fees if TCCs were created, and how congestion revenues would be distributed. In order to avoid delay, confusion and potential economic loss, specificity as to how TCCs would be established and implemented should be provided as soon as possible, so that market participants who want to take advantage of the financial hedge provided by TCCs can do so.

Some parties say there will be little reason to have TCCs because there will be little congestion. But if there is little congestion, then the prices paid for the initial TCCs will probably be low and there will be an orderly system of managing congestion costs before those costs rise, rather than waiting until the last minute and then scrambling to put a TCC system in place under pressures of time and economic duress.

Equity Issues: Will Small Customers Have Access to the Savings a Competitive Market Will Bring?

In the early years of restructuring, reductions in generation costs due to direct access will probably accrue mainly to large commercial and industrial customers because they have greater bargaining power and greater resources to shop for the best deal. Moreover, with the average cost of power from the PX estimated to be around 2.4 cents per kWh, the amount of savings a direct access provider can offer to any customer will be limited. Furthermore, the commodity costs of electric power (the costs that will be paid to the PX or direct access providers) are less than half of the total bill for most customers, and an even smaller percentage for most residential and small commercial customers. For all of these reasons, restructuring may well bring small bill reductions to small customers, although all customers will have the opportunity to increase the value of their electricity purchases as the market provides more products and services. The involvement of retail aggregators will ease this situation for small users, but few of the dozens of marketing firms now entering California's electricity market are targeting smaller customers.

Small customers also may have to incur transaction costs (i.e., spend time and money) to evaluate the offerings of alternative energy service providers and to negotiate contracts, and they may have to pay the costs of installing special meters to record hourly consumption. For large industrial and commercial customers whose electricity commodity costs are a sizable proportion of their total electricity service costs, transaction and metering costs may not be significant compared to the savings from direct access, but for smaller customers, the transaction costs may be prohibitively high. As a result, only those relatively few customers consuming large amounts of electricity will have the opportunity for substantial savings through direct access in the early years of restructuring. Thus, the main savings of restructuring that will accrue to smaller customers will come from the general competitive forces operating: 1) in the PX, and 2) from unbundling of the distribution functions of the UDC. Note, however, that this is likely to result in some customers paying more for electricity than others, reflecting the value they derive from the services they receive and the costs of providing those services.

Unbundling UDC functions may indirectly help small customers take advantage of direct access savings. Specifically, some aggregators -- businesses that combine the loads of numerous customers and seek out the best power deals for them -- would like to provide customer billing, believing that they can be more competitive or provide greater value than the UDC. Unbundling UDC services may enhance the financial attractiveness of aggregating the small consumer market by giving aggregators an opportunity to compete against the UDC in areas besides the profit margin on energy. Thus, unbundling distribution services is important for small customers in two ways: first, it will allow competition to drive down prices in more aspects of electric service or provide greater value for the price than would otherwise be the case; second, it may make it easier for small customers to take advantage of opportunities in the direct access market.

Some small customers may be able to take advantage of direct billing options such as real time, time-of-use pricing. Under such an option, the commodity charge the customer pays for power, from either a direct access provider or the PX, varies according to the different costs of providing power each hour. (At times of high demand, such as summer afternoons, higher cost plants must be run and the price is higher.) Time-of-use pricing can be critical in allowing customers to reduce their energy bills. In the short-run, the consumers' response to a price change is limited to when, how often, and for how long they use energy end-use services. For example, if the price of electricity were to increase, consumers may reduce the use of air conditioning by setting their thermostats higher or turning their air conditioners off altogether during peak hours -- but they are unlikely immediately to buy more efficient air conditioning or to better insulate their homes. Price signals based on hourly energy costs would provide consumers with information that might lead to a choice to substitute consumption during high cost periods with consumption during low cost periods. As metering and information system technologies develop, consumers will be better able to take advantage of hourly price signals. Programmable microchips are becoming less expensive and it would not be surprising, for example, to see appliance manufacturers produce heating and cooling equipment, refrigerators, and electric water heaters that can be cycled at certain times of the day in response to price signals. Implementing time-of-use pricing would improve economic efficiency and allow customers to tailor their consumption and lower their bills.

Promoting Economic Efficiency in the ISO and PX

Some operational aspects of the ISO and PX currently being considered by FERC raise questions as to whether the system could unduly sacrifice economic efficiency or be unfair to some market participants. Potential inefficiencies should be recognized and reasonable attempts made to remedy them as quickly as possible. We have suggestions which would improve the market structure and provide for a smooth transition to an openly competitive market.

The market is designed to operate on a daily basis with 24 hour settlement periods. The PX conducts an iterative-bid energy auction for the next day and submits a preferred schedule to the ISO, based on the results of that auction. Scheduling Coordinators (SCs) also submit preferred schedules to the ISO at the same time as the PX, based on the needs of the energy buyers and sellers that they represent. Both the PX and other SCs are required to submit "balanced" schedules, that is, schedules where demand equals supply. The ISO combines all of the preferred schedules and if there is transmission congestion, the ISO must decide which schedules should be decremented (that is, have less power produced) in the "export zone," and which should be incremented (that is, have more power produced) in the "import zone".

Under the proposed protocol, "Adjustment Bids" are used to allow both the PX and direct access buyers and sellers (through SCs) an opportunity to express their economic preferences in the event that congestion management is necessary. Through Adjustment Bids, the ISO determines an effective market clearing price for energy in each zone, and those who use the congested path pay the differences between those prices. If no adjustment bid is submitted, a buyer or seller is simply a price taker with respect to use of the path. The ISO calculates the anticipated cost of using the congested path and informs the market participants of the resulting Usage Charge at least once before the market closes.

We believe the current proposal (the Phase II filing) will not provide a fully efficient market. The proposed ISO tariff requires the ISO to maintain separation between the resource portfolios of different SCs, by not arranging any trades between SCs as part of the Inter-Zonal Congestion Management process. Instead, the ISO must only increment and decrement loads and resources within each SC portfolio to maintain balanced schedules for each portfolio, resulting in multiple market clearing prices, using higher cost resources ahead of lower cost resources, and potentially resulting in an inefficient market outcome. In contrast, in managing intra-zonal congestion, the ISO is required to use merit order dispatch such that less expensive resources will be the first to be incremented when generation is increased, and more expensive resources will be the first used to decrement when generation is decreased.

A better system would have the ISO publish coded Adjustment Bids and facilitate a "bid-ask" market to provide the information and mechanism needed to allow SCs to find economic solutions. This would maintain the confidentiality of Adjustment Bids and the identity of bidders. The ISO would post the Adjustment Bids on a computer "bulletin board" in coded form so the SCs could arrange their own trades without having the ISO participate as a decision-maker, much as neutral brokers in other markets match buyers and sellers in a bid-ask format without ever identifying the traders to one another. (The tariff language submitted to FERC would limit the publication of Adjustment Bids to those where the SC authorized release of the bidder's identity and eliminate the suggestion that the ISO act as a neutral broker.) This would be a variant of a known and tested trading system used in financial markets and would reinforce the ISO's role as a systems, rather than a market, manager.

The tariff requirement that the SCs' portfolios be separated in alleviating inter-zonal congestion may prevent SCs from requesting the ISO to aggregate their schedules with those of other SCs in order to manage congestion. Portfolio separation was intended to avoid mandatory rescheduling by the ISO for economic reasons and to maximize market participants' choice through the publication of coded bids and the bid-ask market. Creation of an aggregation option would allow efficient trades between SCs who request this service. It would neither require SCs to use this option nor require the ISO to mandatorily reschedule SCs who do not wish to take advantage of the option.

Finally, the proposed ISO tariff allows Adjustment Bids that have not been accepted by the ISO to be revised by the SCs after the day-ahead market closes for consideration in the hour-ahead market, and bids for the hour-ahead market to be revised after the hour-ahead market has closed for inclusion in the real-time market. This provision is appropriate as long as it helps move the system toward a convergent inter-zonal congestion management solution. We do not believe it is appropriate to allow bidders to change their bids in ways that make it harder to reach such a solution. The PX has rules that move bidders toward an efficient solution; similar rules should apply in the ISO.

Market Power

The goal of electric industry restructuring is to transition from a regulated utility monopoly structure to a workable competitive market place. But restructuring will not be in the public interest if it allows some companies to exploit market dominance and stifle competitive market forces.

Market power is the ability of one firm, or a set of firms, to profit from a unilateral price increase. Mere possession of market power is not a violation of competitive market principles; rather, the anti-trust laws and other pro-competitive statutes serve to deter and punish abuses of market power and anti-competitive efforts to acquire or retain market power. The three types of potential market power are:

1. **Vertical market power**, resulting from the ownership or control by a single firm of more than one aspect of electricity production (generation, transmission, distribution). Vertical integration may allow the firm's control of one aspect (e.g., transmission) to subsidize or force higher prices for another aspect (e.g., generation), and thus grant the firm an unfair competitive advantage. The greatest danger is that a monopoly aspect with essentially guaranteed revenues will subsidize a competitive aspect.

2. **Horizontal market power**, resulting from a concentration of ownership or control of any single aspect, such as generation; horizontal market power may allow a generator to withhold generation or game bids in order to force higher market clearing prices.

3. **Locational market power**, where a specific generation facility may provide unique services needed for a particular geographic area and command a premium market price.

A large percentage of California's generation supply will not be competing in the market during the 1998 - 2001 transition period, because it has been designated as either "must-take" (nuclear, hydro, QFs under contracts) or "must-run" (units designated as necessary for reliability). Thus the transitional market will be fundamentally different from the fully competitive market. (Over time, the amount of must-take and must-run generation should diminish, and more resources will be bid into the PX or be available for direct access contracts.)

When generation from must-run resources is required, those generators have locational market power. Two approaches have been suggested to mitigate the locational market power of must-run units: one would limit the recovery of their operating costs through Performance-Based Ratemaking, the other would entail contracts with the ISO for providing some kind of ancillary service payment for providing system reliability. Either option results in the unit not being allowed to set MCP and being paid only its operating costs when it is chosen to run out of economic order ("constrained on") by the ISO.

As a possible mitigation measure against the IOUs' potential horizontal market power, the CPUC has required that during the transition period the IOUs must bid all of their generation into the PX (except for their "must-take" and "must-run" resources) and must also purchase from the PX all the electricity needed for their full service customers. The CPUC believes that those requirements will provide sufficient depth to the PX so that its market signals may be relied upon as a bench mark for consumers who wish to opt for direct access arrangements.

The transmission network can also limit the breadth of the PX market. Demand for electricity at any given location can be met by local generation, remote generation via the transmission network, or a combination of both. In a fully competitive market system, electricity users in every location would have access to several competing generators at all times, but the cost of expanding the transmission network to achieve that level of competition may be prohibitive. As a result, some areas may continue to be served by a limited range of generators (i.e., a thin market would exist). If the thinness of the market at a given location presents the opportunity for locational market power, the generators serving that location should be put on contract with the ISO to limit the opportunities to profit from market power.

Ensuring that the PX is sufficiently robust is one approach to market power mitigation. Another approach would be to rely on a number of "markets," each of which may be individually considered limited or "thin," but in aggregate provide a robust market. The New York Mercantile Exchange (NYMEX) and other markets may well provide for a sufficiently robust overall market, even if individual components are thin.

FERC has the ultimate authority to ensure that wholesale markets are competitive. One mitigation measure is clearly appropriate: government needs to obtain adequate information from the ISO and PX to conduct effective market oversight in order to discover design flaws in the rules and protocols, determine if facilities have been mischaracterized as must-run, and identify bidding behavior designed to take undue advantage of market power. The Energy Commission is analyzing market power, systematically reviewing issues related to ownership of existing generation and the ability to construct new generation in a restructured electricity market. The Commission will continue to review developments now before the CPUC and FERC and to monitor market power abuses when the competitive market begins in 1998.

Financial Instruments and Market Power

The current regulated system provides consumers with a schedule of rates that is fairly predictable and constant; for most consumers rates vary only to the extent that there is a differential for winter and summer. Likewise, from the generators' perspective, fixed rates guarantee a constant revenue stream. The restructured electricity market will offer no such stability or guarantees on prices or revenues once the transition period is over. The market clearing price paid to generators will vary from hour to hour, and, to the extent that transmission congestion exists, from zone to zone. Buyers and sellers from the PX may wish to reduce the risk associated with such price uncertainty through the use of special contractual arrangements such as contracts for differences (CFDs) and TCCs.

TCCs, which were described on page 28, provide their holders with transmission price certainty. By acquiring TCCs, both generators and customers have tools to address the risk of added congestion fees due to locational differences in generation costs.

Buyers and generators can also enter into CFDs. CFDs rebate the difference between the contract price and the price of purchasing electricity from the PX. CFDs provide the financial benefits of direct access in that the generator receives and the customer pays an agreed-upon, fixed price, but the generator does not need to actually generate power. (The generator may purchase power from another source and provide it to the customer.)

An open and competitive market for the buying and selling of financial hedging instruments may also help mitigate the exercise of market power. For example, if a generator sells a CFD which exactly matches the revenue it receives from the PX then it has no incentive to inflate its bid price to the pool. Furthermore, if the generator were to bid a price above its contract price, it would risk not being used to provide electricity.

Hedging instruments also promote the viability of new entrants. With a combination of CFDs and TCCs, a new market entrant can provide the certainty of revenue that is necessary for securing financing. The presence of new generators provides pressure on existing generators not to artificially inflate their bids to the PX, thereby mitigating potential market power.

A futures and options-on-futures market for electricity also will play a role in limiting market power. In 1996, the Commodity Futures Trading Commission (CFTC) approved NYMEX's application to trade electricity futures and options on futures at Palo Verde and at the California-Oregon border. The market's liquidity has been growing as new players enter the market.

Chapter 4

EFFECTS OF RESTRUCTURING ON RELIABILITY

Introduction

The Legislature has often spoken of the critical need for electric system reliability in California. Most recently, in Assembly Bill 1890 (AB 1890) the Legislature declared that reliable electric service is “of paramount importance to the safety, health, and comfort of the people of California." (Public Utilities Code Section 334.) For customers, reliability is a simple matter: when the switch is flipped, does the power come on and does it stay on? But ensuring reliable service is a complex matter. Reliable service requires investments in many different types of facilities and lots of work, from adequate maintenance of transmission rights-of-way, to planning for sufficient local generation, to operator training. Industry restructuring will not affect the physics of reliable electric service, but it will change the entities responsible for reliability and change the economic incentives affecting reliability investments.

AB 1890 states that restructuring of the electricity industry will transfer responsibility for ensuring short- and long-term transmission reliability away from electric utilities and regulatory bodies to the Independent System Operator (ISO) and various market-based mechanisms, but it also declares that the state should ensure that "the change in the locus of responsibility for reliability does not expose California citizens to undue economic risk in connection with system reliability” and that “restructuring should enhance... reliability.” (Public Utilities Code Sections 330(q), 334.)

Any discussion about the locus of responsibility for reliability must recognize that California does not act alone, nor does it completely control its own destiny. For example, the two major outages of the summer of 1996 cost California electricity consumers millions of dollars, yet the events that triggered them began in Idaho and Oregon. As another example, decisions about the federal budget affect the amount of tree-trimming the Bonneville Power Administration (BPA) can perform near its transmission lines -- lines that carry power to California.

The outages of July and August 1996 heightened regional and national concerns about reliability. Western system operators have prided themselves on their ability to prevent systemwide disturbances and to collectively recover quickly when an earthquake, lightning strike, or forest fire took out major transmission lines. That confidence was eroded last summer, when contingencies that shouldn't have happened brought down substantial portions of the Western grid. Even if no restructuring were taking place, reinforcing system reliability would be a regional priority. Already, changes in management, maintenance practices, operations, monitoring and enforcement are occurring throughout the West.

Many electricity industry members now believe that the voluntary agreements of regional coordinating councils will be insufficient to keep the system functioning at its historically high levels in a more competitive environment. Most parties agree that while the North American Electric Reliability Council (NERC) and its regional councils such as the Western Systems Coordinating Council (WSCC) have done an excellent job of developing reliability protocols during the past 30 years, the Councils’ current voluntary standards must soon have some enforcement mechanism to keep a more heavily utilized system free of major problems.

This chapter first describes how AB 1890 will affect the responsibility for reliability activities and investments. It then examines the four major categories of reliability:

- Distribution reliability: Most power outages are a result of distribution system failures. Will restructuring affect distribution system reliability, even though the ownership and regulation of distribution will not change?

- System operating reliability: On a day-to-day basis, do sufficient generation and transmission facilities exist, in the proper configurations? Are the transmission facilities properly operated and adequately maintained?

- Reliability of individual power plants: In contrast to the transmission and distribution systems, power plant ownership will cease to be an exclusively or even predominately monopoly function. In a competitive market, will there be adequate incentives for power plant maintenance?

- Construction of reliability-critical facilities: In the long-term, will the economic incentives of a competitive market be sufficient to ensure that reliability-critical generation and transmission facilities are built?

How Will Restructuring Affect the Responsibility for the Reliability of California's Electrical System?

AB 1890 vests substantial responsibility for reliability of the bulk transmission system in the ISO. (The CPUC, IOUs, and POUs will remain responsible for distribution system reliability.)

The ISO has the responsibility to ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council [WSCC] and the North American Electric Reliability Council [NERC]. The WSCC and NERC Criteria are designed to prevent local disturbances from cascading to neighboring systems. To carry out its reliability responsibilities AB 1890 gives the ISO substantial powers and duties:

- The ISO may [subject to Federal Energy Regulatory Commission (FERC) approval] "secure generating and transmission resources necessary to guarantee achievement" of planning and operating reserve criteria no less stringent that those of WSCC and NERC. (Public Utilities Code Section 346.)

- The ISO must adopt "inspection, maintenance, repair, and replacement standards" for the transmission facilities under its control and standards for reliability and safety during emergency and disaster conditions. (Public Utilities Code Section 348.)

- The ISO will perform a review of all future major outages. If the ISO "finds that the operation and maintenance practices of the transmission facility or owner prolonged the response time or was responsible for the outage, the ISO may order appropriate sanctions," if FERC approves the authority of the ISO to do so. (Public Utilities Code Section 349.)

AB 1890 also requires the ISO, in consultation with the Energy Commission, the CPUC, the WSCC, and regulatory agencies in other states, to provide to the Legislature a comprehensive report on all aspects of reliability. The report must be submitted within six months after FERC approval of the ISO. (Public Utilities Code Section 350.)

Finally, in AB 1890 the Legislature has declared its "intent" that California enter into a compact with other western states that would require out-of-state utilities that sell to California customers to adhere to reliability standards. (Public Utilities Code Section 359.) There also will continue to be integrated regional planning for the entire western United States, coordinated through WRTA and the Western Integration Coordination Forum.

How Will Restructuring Affect Distribution Reliability?

Most power outages are caused by distribution system failures, not by problems originating with the generation or bulk transmission systems. When restructuring is complete, power plants once owned by monopoly utilities will be subject to full competition, and transmission lines will be operated by the ISO. In contrast, ownership and operation of the distribution systems will remain under the control of the same monopoly utilities and regulatory agencies that are currently responsible for them. The competitive pressures, however, that restructuring brings may have an indirect effect on reliability; for example, the IOUs have reduced distribution maintenance expenditures as part of their cost-cutting efforts to prepare for competition. Nevertheless, performance-based ratemaking (PBR) for distribution functions should provide economic incentives to improve reliability. In addition, AB 1890 states that the CPUC (1) must adopt inspection, maintenance, repair, and replacement standards for IOU distribution systems; (2) must perform a review of every major distribution system outage; and (3) may penalize inadequate performance through rate reductions or fines. In light of all those factors, distribution reliability is unlikely to suffer as a result of restructuring -- and it may well improve.

How Will Restructuring Affect System Operating Reliability?

Even though most reliability problems are geographically limited, affecting only local distribution systems, it is the failures of major regional transmission lines that are the most economically devastating. System operating reliability focuses on the entire system and is implemented via the "operating" reserve margin, which is designed to ensure that enough generation and transmission facilities are available all day, every day, to serve expected load and to have some margin in case of unexpected outages. (Operating reserve margin suggests a lower level of reserves than "planning" reserve margin, which is a long-term measure. A planning reserve margin is designed to ensure adequate facilities in future years to maintain the then-current operating reserve.) Utilities try to maintain system operating reliability in the most economic manner possible, but sometimes reliability-critical actions must be taken at extra cost; for example, if it is cheaper to run plant A than plant B, but running plant B is necessary to maintain reliability, then plant B will be run.

Individual IOUs and POUs are currently responsible for maintaining system operating reliability, following WSCC guidelines. Under AB 1890 the ISO will take over that responsibility from the utilities that join the ISO, although the transmission-owning utilities will still be responsible for the actual maintenance of the grid. The ISO will be responsible for directing operation of the network in accordance with reliability criteria at least as stringent as the NERC and WSCC reliability standards. The ISO will also be responsible for intra-system reliability through its acquisition of ancillary services, scheduling, congestion management, local reliability contracts, automatic generation control, and transmission operating protocols.

It is unclear whether restructuring will make system operating reliability within California better or worse (and because of the heightened national and regional concerns about reliability it will be impossible to separate the effects of restructuring from the effects of other reliability-related activities.) The ISO should be in a better position to identify potential wide-ranging regional emergencies, isolate problem areas, and prevent cascading inter-system failures. On the other hand, there will be competitive pressures to maximize the use of existing generation and transmission resources, which may cut into the buffers that currently provide an extra measure of protection if multiple things go wrong at the same time. Furthermore, the ISO must also try to balance the need for a coordinated and comprehensive assessment of options available for maintaining system reliability against the desire of stakeholders that the ISO not become a "central planner." Stakeholders would like to use market-based solutions for reliability problems, but they are understandably uncomfortable with the idea of experimenting on consumers: letting the market try (and fail) is not a palatable outcome.

The first major ISO decision affecting reliability will be the designation of reliability-critical power plants. The CPUC has ordered that during the four-year transition period, all power plants owned by investor-owned utilities (other than “must-take” plants) must bid all their power into the PX. Ordinarily, the plants submitting the cheapest bids will be the ones that get dispatched and receive revenue. Certain plants, however, must be run regardless of cost in order to maintain reliability. (For example, certain plants on the San Francisco Peninsula must run in order to maintain proper voltages in the local system, even if cheaper power could be obtained elsewhere.) The IOUs have claimed that a large proportion of their plants are reliability-critical and therefore should, at times, be dispatched out of “economic merit order" even if other plants are less expensive. The ISO needs to consider such claims carefully and ensure that only those plants truly needed for reliability are dispatched ahead of cheaper units. In addition, determining how much of a reliability-critical plant’s fixed costs must be guaranteed to ensure the plant’s availability when needed, and how the plant will sell to the PX at other times, will be a difficult task.

How Will Restructuring Affect the Reliability of Individual Power Plants?

Under the current system, regulated utilities are responsible for the reliability of most power plants; in addition, in the past two decades independent power producers (IPPs) have built plants for which they are responsible. Because utilities have had an obligation to serve, high reliability standards to meet, and a guaranteed opportunity to recover prudent costs incurred to meet their obligations, utility power plants are very reliable, with rugged equipment, redundant critical systems and components, rigorous quality control, and conservative maintenance. IPP plants are also very reliable, because the "Standard Offer" contracts under which power is sold to utilities have provided financial incentives for continuous operation.

In a competitive market, where power plant owners will have no obligation to serve or responsibility for system reliability, there will be financial incentives to cut costs by installing fewer redundant systems, doing less quality control, and reducing maintenance. Market forces, however, will demand a reasonable level of reliability. If a power plant has a bilateral contract, when it is not operating it must pay someone else for power to supply to its customer; if a power plant is selling into the PX, when it is not operating it does not get paid and if it fails to deliver after winning the PX auction, it will have to pay for replacement energy.

There is good reason for optimism, therefore, that in the long-run restructuring will not have a significant effect on power plant reliability. Moreover, if cost-cutting measures cause short-term problems, any adverse effects of decreased power plant reliability will be softened by the system's currently large reserve margins.

Will Market Incentives Be Sufficient to Encourage the Construction of Necessary Facilities?

A fundamental requirement of an electricity system is to have enough power plants to supply the needs of customers. In the regulated monopoly electricity system, having enough facilities for reliable service is ensured by state government regulators who require investor-owned utilities to serve customers and who set the rates necessary to pay for reliability-essential facilities.

In a fully competitive market, government will no longer determine the appropriate level of reserves. Moreover, responsibility and incentives for new construction will be more diffuse. Divestiture of generation, transmission, and distribution may reduce each entity's economic incentives to upgrade or build new facilities, because, although more parties will have incentives, the incentives for individual actors may be smaller than was the case for the vertically integrated utilities.

Under AB 1890, the ISO has the authority to "secure generating . . . resources necessary to guarantee achievement" of planning and operating reserve criteria. (Public Utilities Code Section 346.) The scope of that authority is not entirely clear, and it would be preferable to rely on market forces, rather than the quasi-governmental ISO, to be responsible for making the major investment decisions that new power plants and transmission lines represent. Thus the obvious question arises: will the economic incentives provided by a competitive market attract sufficient investment to construct the facilities needed for reliable electric service? Although many uncertainties are involved, there are reasons to be cautiously optimistic.

Construction of New Power Plants

This section explains the following matters:

- The revenues new power plants will have to receive in order to be financially viable

- Why the revenues most new power plants will receive will probably track PX prices closely

- The likely PX prices that will prevail during the first several years of the PX

- Whether power plant revenues are likely to be high enough to provide adequate incentives for new plants

- The prices consumers will have to pay to provide such revenues

ER 94 contains estimates of the amount of revenue that different types of new power plants would have to receive in order to cover their fixed costs and profit, given various assumptions about the initial capital cost, the rate of return that bondholders and stockholders would require, and so on. (The estimates are based on IOU financing.) For example, a combined-cycle plant, generally the cheapest type to build and operate, would need to earn approximately $114 per kW of capacity per year during the life of the plant -- above and beyond revenues necessary to cover operating costs -- in order to be financially viable. (The $114 per kW/year figure is subject to numerous assumptions and is used here for illustrative purposes only.) Although other types of plants may be more economic in certain applications or in "niche" markets, current revenues from power sales are not high enough to support new combined cycles. As long as generating supplies substantially exceed demand, as they do now, generators' bids will set the market clearing price (MCP) in the PX. When demand exceeds supply, then customers' "demand bids,"-- the price above which a customer will not take power, or at which a customer will curtail power consumption -- will set the MCP. Revenues for most new power plants are likely to closely track PX prices; even the plants that rely solely on direct access contracts are likely to have contracts that provide for near-PX prices (many marketers have stated that they intend to offer customers deals such as "five percent below PX prices"). In any event, direct-access prices are not likely to deviate substantially from PX prices, and thus PX prices provide a good proxy for both.

Generators' bids are likely to very closely track the operating costs of power plants. That is because generators will bid as low as they can because doing so maximizes their chances of being dispatched and receiving revenues, and "as low as they can" is, basically, the plant's variable operating cost (fuel cost plus variable operating and maintenance cost). Bidding higher than operating costs would cause a loss of potential net revenue during the hours when MCP is higher than operating costs but lower than the price bid. Therefore, generators will tend to bid their operating costs, and thus as a general matter the operating cost of the highest-priced power plant needed to meet PX demand will set the MCP.

Currently, the operating costs of California power plants generally do not exceed $50/MWh (5 cents/kWh). (Total rates are substantially higher than 5 cents/kWh because rates include not just the operating costs of power plants but also all the other costs of providing electricity service, such as the capital costs of power plants, transmission and distribution facilities, public interest programs, and metering and billing.) For example, the highest-priced power plant used by Edison in 1994 had operating costs of about $42/MWh. This means that in a hypothetical PX using all of Edison's plants, the highest MCP during the year would be $42/MWh; at other times MCP would be as little as $11/MWh.

Such prices are not likely to attract many new generators into the market. Even a plant with very low operating costs dispatched virtually all the time -- for example, a highly efficient new plant with a 7,200 Btu/kWh heat rate, operating with cheap natural gas at $1.92/MMBtu, and dispatched 97 percent of the time -- would earn only $85/kW per year toward fixed cost recovery and profit with revenues of $50/MWh, well below the $114/kW or so needed. Therefore, not until demand approaches supply (when demand bids, rather than supply bids, will set MCP) is substantial new power plant investment likely to be seen in California. This reflects a basic maxim of economics: when supply exceeds demand, prices are low, leaving little incentive for additional suppliers to enter an already glutted market; when demand grows and supplies are scarce, higher prices and greater incentives for new suppliers result.

How high must demand bids go to encourage new power plant construction? Probably very high -- but only for a small number of hours. If demand bids were $1,000/MWh (one dollar per kWh, about 10 times current average residential rates) during one percent of the hours of the year, the hypothetical power plant discussed in the preceding paragraph would clear $170/kW per year towards its fixed costs and profit -- probably enough to attract investors. Demand bids that high seem outrageous, but if they occurred during only one percent of the hours of the year the effect on customer bills would be small. For example, if the hours were divided equally between July and August, the increase for a typical residential customer would be about $40 in those months. Although not insignificant, this amount may be bearable for most customers -- and it is likely to be more than made up by the low PX prices that would prevail at other times of the year. Moreover, it may well be better to let the market provide incentives for reliability than to rely on high payments from the ISO to pre-designated “must-run’ or “reliability-critical” power plants.

When will demand begin to exceed supply? **Table 12-2** in Chapter 12 indicates that the state's current power plant surplus is likely to disappear in the early years of the next century. At that time economic incentives should become large enough to attract substantial investment in new power plants. The Commission currently has one power plant application. Several others are expected; if approved, the plants would start in the early 2000’s.

In sum, the Commission is reasonably confident a fully functioning PX market with supply and demand bids will provide adequate incentives for investment in new generation and that the price consumers pay for new supplies in a competitive market will be reasonable. But it bears emphasizing that such a market requires effective demand bidding, which in turn means adequate meters and load controllers. Fortunately, the necessary technology already exists at a reasonable price, at least for larger customers; whether it can be deployed in sufficient numbers quickly enough is uncertain. More problematic may be the political will to accept high prices during a few peak hours.

Keeping Older Power Plants Running

One substantial unknown about the competitive market is the extent to which old, inefficient power plants will be able to make enough money to stay in good operating condition. Generators that are without bilateral contracts (i.e., that are selling only through the PX) and that operate infrequently may not be able to recover enough money to stay in business. Uneconomic utility plants will be able to recover their capital costs through the CTC during the transition period, but fixed operating and maintenance (O&M) costs that are incurred even if the plant does not operate are not recovered through the CTC. If older plants cannot recover fixed O&M costs through PX revenues, they may have to be scrapped, possibly leading to rapidly shrinking reserve margins. The ISO’s responsibility, however, to maintain WSCC and NERC reliability standards will be a counter-balancing force. Initially, the ISO will enter into standardized contracts with reliability-critical facilities; the contracts will provide enough money, in the short-term, for the facilities to be maintained in good condition. In the longer term, ISO incentives may provide an opportunity for new generators to enter the market.

Transmission Lines

The CPUC has declared that the principal impetus for transmission investments should come from market forces and that if there is a market failure leaving important modification undone because of an inability of market participants to agree on a sharing of the costs and benefits, then regulators should authorize the construction and assign the costs of the investment and the benefits of new transmission congestion contracts among the various users of the system. We agree. Thus, there should be (1) a primary mechanism in which those who would economically benefit from transmission expansions propose and pay for them, and (2) a backstop for situations in which market participants cannot agree on payment for upgrades necessary for reliability or economic efficiency, in which a third party (the ISO or a regulatory agency) would allocate the costs and future congestion management fees. Such a system will go a long way towards ensuring construction of reliability-critical transmission lines. Getting transmission pricing right with the methods discussed in Chapter 3 is also crucial in ensuring that appropriate incentives exist for new transmission line construction.

One of the difficulties in ensuring transmission system reliability is that the regulatory structure for transmission lines is complex. Jurisdiction over rates and terms of service is different from jurisdiction over the siting of new lines, and within each category jurisdiction is further fragmented. Currently, FERC has rate and service jurisdiction over all wholesale (interstate) transmission service owned by “public utilities” as defined in federal law; the CPUC has rate and service jurisdiction over retail transmission lines of the IOUs; and POUs regulate their own lines. (Licensing jurisdiction for new lines is discussed in Chapter 12.)

After restructuring, the day-to-day control of the IOU transmission grid, and all lines of participating POUs, will be turned over to the ISO. The ISO will be subject to FERC jurisdiction over rates and service.

As discussed previously, the ISO will be given substantial responsibility for system reliability; to help carry out that responsibility, the ISO will be able to impose certain obligations on Transmission-Owning utilities (TOs). Each TO will be obligated to construct all transmission additions and upgrades that the ISO determines are needed within the TO’s service area, subject to the TO’s ability, after making a good faith effort, to obtain necessary permits and subject to the availability of appropriate cost-recovery mechanisms.

In addition, there will be an ISO-supervised planning process. Each year each TO must submit a transmission plan, covering at least the next five years, showing transmission facilities and upgrades that are sufficient to meet applicable reliability criteria. The ISO will review each plan to determine if it is adequate. If the ISO believes a plan does not provide sufficient reliability, the ISO will suggest changes; if the TO does not accept the changes the issue will be resolved through a dispute resolution process. The TO is obligated to construct any facilities determined to be reliability-critical.

Independent of the TO plans, a TO, the ISO, or any other market participant may propose a transmission system addition -- either to maintain reliability or to improve economic efficiency. If the proposer(s) do not agree on allocating the costs, the costs (and benefits, such a as the ability to receive transmission congestion fees) will be allocated by the ISO or, ultimately, by FERC. FERC can also order transmission upgrades to be made.

A final issue with regard to the construction of new transmission lines is related to the separation of Scheduling Coordinator portfolios, which we discussed on page 30. That separation will result in higher congestion fees than would otherwise be the case, which in turn could result in transmission expansions that are more costly than the alternative of not separating the portfolios and redispatching lower-cost resources to manage transmission congestion.

Chapter 5

ENVIRONMENTAL EFFECTS OF RESTRUCTURING

The Energy Commission endorses an outcome from restructuring which maintains existing levels of environmental quality. The many uncertainties still remaining about the structure and operation of the new system, however, raise questions about environmental impacts. What will be the market clearing price at the PX? Will the market warrant construction of new facilities sooner or later? How will transmission congestion pricing affect system dispatch? And what units will remain “must-run” for reliability and voltage support? Our ability to assess air quality and other environmental impacts depends on the answers to these questions and the availability of modeling tools necessary to predict the dynamics of a highly complex market.

In the Energy Commission's proceedings on ***ER 96***, experts expressed disparate views on the answers to those questions and the nature and extent of likely environmental effects from electricity industry restructuring. Some experts believe that only minor, second-order effects on the location, size, and type of new plants and transmission lines seem likely; others anticipate an 8- to 10-year standstill in power plant development; and yet another view is rapid technological changes in the next 10 to 15 years, including the development of small photovoltaic and fuel cell power plants in remote and distributed generation applications.

Restructuring may not, by itself, necessarily result in greater or fewer environmental impacts, nor does divestiture of utility power plants, by itself, necessarily mean that power plant emissions will change. Rrestructuring and divestiture of generation facilities, however, may change economic decisions when to run, retrofit, refurbish, repower, replace, or retire existing power plants. Such decisions could also result in different power plants being cost effective to operate than was the case without restructuring.

Future Uncertainties

Several uncertainties contribute to the difficulty in forecasting restructuring's environmental effects. We focus in this chapter on air quality effects because they are perceived to be the most important environmental effects of power plant construction and operation.

Air quality impacts will, in general, result from changes in the way and the times when the generation system operates. Depending upon which direction those changes take, the resulting changes in emissions could either be beneficial or provide greater challenges for air quality attainment in California.[1] The most important variables potentially affected by restructuring are:

- ♦ Changes in operating hours of existing power plants
- ♦ Timing and extent of new power plant construction
- ♦ Use of distributed generation
- ♦ Changes in timing and level of customer demand

The first variable is operating changes -- either total annual or hourly -- of existing power plants. Increased operation of some existing plants may change emissions, depending on the types of generation facilities being operated. The operation of existing fossil units could increase if nuclear facilities decrease operation due to lack of competitiveness or early retirement; increased operation or output could also result from repowering existing fossil facilities. Conversely, increases in price differentials from one hour to the next will tend to decrease demand during periods of high prices, which in turn will tend to reduce the use of currently marginal units with relatively higher emission rates.

Second, operation also could change if there is a lack of timely, competitive power plant additions or changes in ownership due to divestiture of utility plants. The timing and extent of new power plant construction is not known at this time, although at some point new power plants are certain to be constructed. The Energy Commission expects four large plants and perhaps a few smaller facilities to file permit applications in 1997. Since these will be state-of-the-art, efficient natural gas facilities subject to New Source Review (NSR) and Best Available Control Technology (BACT), they will operate with far lower emission rates than existing fossil facilities. Their licensing, however, is likely to consume numerous emission "offsets"[2] within the various air quality districts, particularly for nitrogen oxides (NO_x) and particulate matter of less than 10 microns (PM_{10}). Since a large percentage of emissions is in the mobile sources area, they provide an important potential source, if effectively harnessed, for stationary offsets. From a local perspective, available offsets are prized by local air district regulators wishing to encourage other forms of economic growth which produce higher employment and larger local revenue streams than power generation. Additionally, increased demand for offsets in a scarce market could cause the price of offsets to escalate, making remaining offsets prohibitively expensive for other business enterprises.

A third variable is the use of Distributed Energy Resources (DER). These small generation facilities may prove more attractive in a competitive market to those seeking to increase reliability and grid independence by self-generating. For the DERs that are fossil fueled units, some may emit at higher rates than conventional power technologies. Although some air districts have expressed concern about DER having higher than acceptable emission levels, manufacturers of gas- and liquid-fueled microturbines and advanced turbine systems have bench test results showing that they will meet or beat current target emission goals for NO_x and other emissions. These distributed generation units, however, may be too small to trigger the minimum emission threshold pollution control levels currently established in air district permit rules [NSR or Prevention of Significant Deterioration (PSD) regulations[3]]. Air quality regulations need to account for this technological innovation. Otherwise, widespread deployment of DER units could create emissions greater than anticipated in air quality management plans. Whether such increases are significant will depend on the location, number, and mix of DER technologies added to the system.

A fourth variable is how electricity consumption will change in response to the new market-based prices for electricity. Since the essential goal of restructuring is to gain system efficiency through market forces, all customer classes should eventually see price reductions. In turn, these price reductions are likely to result in an increased use of electricity. From an environmental perspective, increased demand can result in increased emissions, depending on the type and timing of generation used to meet marginal generation needs. Increased use of TOU rates by consumers can also affect emissions. One example of how emissions could change is if TOU rates encouraged large numbers of customers to decrease consumption during the traditional late afternoon period of peak electricity demand. If the peak demand were substantially reduced, it would affect the dispatch of power plants. Since less efficient power plants with higher emissions are normally dispatched to help meet periods of peak demand, emissions could be reduced if these older, dirtier power plants had to operate less, or not at all.

If TOU rates modify electricity consumption patterns, decreasing use in the afternoon and increasing consumption in the morning hours, shifts in air pollutant emissions will occur. Consequently, there would probably be increased emissions during the morning hours. Increased emissions during the morning hours of NO_x, which can interact with sunlight to form ozone, a pollutant, could impact air quality. However, because the air districts and regions in the state have different meteorological and topographic conditions, and a different mix of emission sources, modeling in individual air districts is needed to assess the potential impacts that may occur due to changes in daily and peak electricity consumption patterns and variable electricity prices.

Another difficulty in estimating the effects of demand changes will be determining the incidence of fuel switching, either to achieve environmental benefits, such as the increased use of electric vehicles in the transportation sector, or to take advantage of the lower prices of other fuels, as has been seen in the agricultural sector, switching away from electricity.

Agricultural Energy Use

Agricultural electricity rates have been rising since 1988, while deregulation has lowered natural gas prices. One result of higher electricity prices in California has been an increasing trend among farmers to switch from electricity to natural gas or diesel fuel to power irrigation pumps. If the recent historical trend continues, fuel switching in the agricultural industry could double the NO_x emissions in the San Joaquin Air Basin from irrigation pumping in as few as seven years. There are several reasons, however, to expect the rate of fuel switching, and thus increased emissions, will decline rather than continue to increase.

First, although under current conditions diesel and natural gas pumps are more economic than electric pumps for many farms, declining electricity costs will make electricity more competitive. This is expected particularly after 2001, when the competition transition charge (CTC) ends.

Second, AB 1890 allows some irrigation districts to qualify for portions of 110 MW of load exempted from the CTC (effective as early as January 1998), with half of the exempted load reserved for customers using electricity for agricultural pumping. This CTC exemption will reduce the economic incentive to switch fuels for those customers that qualify.

Third, farmers are likely to continue to increase their use of more efficient irrigation systems and gradually shift acreage toward crops with lower energy and water costs. As this happens, the cost of agricultural pumping -- whether by electricity or natural gas -- will become less significant.

Traditional Regulations and Market-Based Incentives

Our goal is to balance economic efficiency with the equally important public interest of environmental quality. This balance can be achieved by using a mix of available tools, both market-based mechanisms and traditional, “directive” approaches which need not be seen as mutually exclusive. A combination of approaches may prove most effective in achieving a balance which maximizes economic returns while still protecting public purpose goals of environmental quality.

Traditional tools: Regulators continue to rely on and refine conventional tools, an array of old and new approaches which use a predominantly prescriptive approach, e.g., unit-specific emission limits, technology installation requirements, and dispatch limitations based on emissions. In the past, air districts adopted rules requiring best available retrofit control technologies (BARCT) for existing power plants and best available control technology (BACT) -- normally more stringent -- for new power plants. These measures were key components of most district strategies to achieve attainment with both state and federal ambient air quality standards. While in this period of focus on markets and competition it may be tempting to abandon all of these tools, electric competition need not derail those that prove to be effective transition tools.

Another aspect which should be considered by local air districts is the threshold for the applicability of rules that apply only to emission sources above a certain size. Smaller power plants, built as a result of restructuring and/or advances in technology, might otherwise not be subject to current regulations.

Market-based tools: As energy regulators have moved to embrace deregulation and competitive markets, environmental policy makers have also been developing mechanisms that use market forces. Central among these are several types of trading programs, including the Federal SO_2 program entering its second phase, the proposed Federal Open Market Trading Rule, and the Regional Clean Air Incentives Market (RECLAIM)[4] program covering larger NO_x and sulfur oxide (SO_x) emitters in the South Coast AQMD. The direction of the South Coast AQMD, which is combining emission credit trading programs with fees, illustrates the various ways economic incentives can be used to improve environmental quality. By combining RECLAIM, which targets the reduction of emissions, with other rules that also allow non-RECLAIM sources to create credits to sell or reduce compliance costs, the number of participants will expand, increasing the opportunities for both emission reductions and cost-savings.

Although these programs have been successful in achieving emission reductions at a lower cost, they do not come without complex design challenges. Central among these challenges are deciding which sources to include, how to determine baseline emission rates, whether to allow banking, and how to treat new sources.

Using Economic Principles

Restructuring notwithstanding, there may be more efficient ways than existing mechanisms to improve air quality. We believe market mechanisms are a valuable approach to balance environmental quality with economic efficiency. Traditional source-specific regulations provide no incentive for reducing emissions further than required and often impose inconsistent costs across emission sources. For example, the cost-effectiveness of retrofitting a power plant with a new emission control technology will depend on site-specific factors that determine applicability, emission reduction performance, and cost. Unless air districts write individual rules for each power plant, different firms complying with the same rule will bear different costs. It is important that emissions from different sectors and fuels -- electricity, natural gas, and transportation -- be treated equivalently so that fuel and technology choices can be accurately weighed for their benefits and values. Correct pricing not only encourages efficient choices by producers and consumers, but can also stimulate investment in new, cleaner technologies. The Energy Commission continues to support the policy that sources of emissions should bear the cost of their emissions.

Successful use of market-based environmental regulations will depend on adherence to several key economic principles:

- Incentive programs should include as many emissions sources as possible, increasing opportunities for cost savings, faster attainment of air quality benefits, and stronger incentives for technological innovation. Including only major sources such as power plants may exclude potentially lower-cost emission reduction opportunities from smaller sources which in aggregate contribute a much larger share of emissions.

- Each source should bear costs in proportion to the damage caused by its emissions. When firms bear the total costs of their actions, then siting and operation decisions are economically efficient.

- The program objectives and constraints of alternatives for incentive-based emission programs should be clearly defined. Before any particular alternative is chosen, it must be analyzed under the conditions of its application. Local and regional pollution formation, existing programs and laws, and the electricity supply system will in part determine the effectiveness of any new program.

- Building on existing programs will reduce compliance costs and strengthen demand for emission reduction technology. The use of tradable emission credits as a cost-saving compliance strategy and the intersource emission trading guidelines the California Air Resources Board (CARB) recently adopted under AB 1777 are examples of ways to incorporate incentives into existing programs.

- Regional and interjurisdictional cooperation and planning should be promoted in recognition of the regional dimensions of ozone and haze formation. Regional planning, however, should be balanced with the specific characteristics of local conditions.

Air Quality Forums

Coordination and exchange of data analysis will be central in achieving optimal environmental outcomes at regional, state, and federal levels. To facilitate communication on air quality and restructuring issues, the Energy Commission staff have created an Air Quality Forum (Forum), as called for in ***ER 94***, which involves regional and state air and energy regulators. One activity of the Forum involves regular meetings with the planning managers of the California Air Pollution Control Officers Association (CAPCOA) to discuss various air quality aspects of the transition to a market-based pricing system.

Conclusions

Uncertainty exists over the eventual environmental impacts of restructuring which precludes us from judging whether the environmental impacts of restructuring will on balance be positive or negative. To date, we have neither evidence of any circumstances which we believe will result in significant, unavoidable adverse environmental impacts nor any that are certain to result in significant environmental benefits. As the markets adjust and respond to customers' choices, long- and short-term changes will occur. We are not able to model such changes to predict what the environmental impacts or benefits will be -- given the uncertainties of how markets might respond and the uncertainty related to industry restructuring issues. Replacing existing power plants with new and cleaner plants will most likely benefit the environment, but the extent to which the market and regulators will encourage new plant development is unknown. Because we cannot accurately predict likely changes at this time, we will continue to monitor the environmental impacts of the regulated electricity system and work cooperatively with energy and environmental stake holders and regulators. We are committed to preserving and enhancing the benefits of California's environmental quality as we transition to a competitive electricity industry.

To accomplish this objective**,** the Energy Commission should jointly maintain its analytical efforts in cooperation with the CARB and the air districts to closely monitor and evaluate the unfolding events of restructuring. These efforts will allow regulators to recognize, assess, and respond to the effectiveness of existing rules and mechanisms, and to the potential for environmental changes.

Endnotes

1. On March 27, 1997, the CPUC released a report prepared by Graystone, a private consulting firm, on the potential environmental effects of restructuring. Although much of the report has been eclipsed by AB 1890, the analysis has furthered California's policy debate by identifying and categorizing factors that both significantly affect environmental impacts and are affected by policy.
2. Offsets are typically required for larger facilities at a ratio greater than 1:1. Therefore, new emission sources that are offset can produce a net emission reduction as high as 100 percent (2:1). Additionally, the offsets are based on historical operation, not permit limits, of the emission reduction source. Since

most air emission sources operate at less than permitted values, the conversion of historical emissions to offsets reduces the potential air emissions inventory.

3. The NSR program is a federally mandated program that applies to nonattainment pollutants. The PSD program applies in areas that are in attainment of the national ambient air quality standards.

4. The Regional Clean Air Incentives Market (RECLAIM) is a market incentive program designed to allow facilities flexibility in achieving emission reduction requirements for NO_x and SO_x. The program allows facilities to use various methods to stay within their annual emission allocation, choosing the most cost effective technology or mechanism, and the timing of its implementation.

Chapter 6

ENERGY EFFICIENCY

The Transformation of State Energy Efficiency Policy

For two decades, the state of California has encouraged cost-effective investments in energy efficiency in order to reduce energy and environmental costs and to preserve energy resources. That goal should not change. For several years, however, the methods used to attain energy efficiency goals have been shifting -- the focus has changed from purchasing energy efficiency with public funds to achieving sustainable transformations in energy efficiency markets.

The "market transformation" approach reduces market barriers to the purchase of energy efficient products and services so that all customers will eventually have the knowledge and skills to purchase appropriate products and services on their own, without the need for on-going publicly-funded programs. (There may be some market barriers, however, that cannot be reduced to a level at which publicly-funded efforts are no longer needed.) The shift to market transformation has come about because scarce public dollars cannot be used indefinitely to subsidize private market transactions and because it is more economically efficient to create viable markets where buyers and sellers make their own decisions instead of government determining which types of transactions are more deserving of subsidies.

Market transformation programs seek to create the following basic conditions of a well functioning market:

- A range of energy efficiency choices is available to customers from credible energy service suppliers.
- The customer's cost of finding the available energy efficiency choices is reasonable.
- Customers have access to tools or services to select among the choices.
- Customers have assurances that equipment will perform as advertised and the ability to evaluate the performance of installed equipment and delivered services.
- Customers have an opportunity to address problems identified after the purchase of equipment or services.

To achieve those conditions, program designers should focus on market barriers that are not likely to be reduced or eliminated by the private sector. Some examples of market barriers and market transformation approaches to removing them are:

Market Barrier:
High customer costs to search for and find energy efficient equipment and then evaluate its costs and benefits vis-à-vis “standard equipment” in order to make a purchase decision.

Market Transformation:
Provide customers with more convenient access to lists of high efficiency equipment suppliers or energy supply firms, encourage the use of standardized “efficiency” labels, and encourage the development of easy-to-use tools that assist customers in making decisions on the purchase of energy using equipment.

Market Barrier:
Customer uncertainty about high efficiency product performance.

Market Transformation:
Encourage manufacturers and energy service companies to provide better warranties and service; encourage the formation of energy

service providers that can routinely "rate" the energy efficiency of long-life investments and help customers compare the costs and benefits of higher-efficiency designs or equipment; and develop software tools or better bill formats that will allow customers to verify for themselves the advertised savings or performance of their energy efficiency purchases.

Market Barrier:
Resistance in the design professions to introducing more energy efficient homes, buildings, and equipment.

Market Transformation:
Encourage universities to develop lighting and building design curricula; work to internalize the energy savings resulting from more efficient design into building lease and ownership transactions; and sponsor training, design competitions, and professional certification courses to identify and promote better design practice and to ensure qualified professionals receive recognition.

Market transformation programs may not produce the same level of **measurable** energy savings as the old "resource acquisition" approach, at least in the short run. Their focus is on changing the information and products available to customers rather than stimulating sales of specific energy efficiency products and services. Market transformation, however, probably will yield more significant and persistent energy savings in the long run because of the significantly greater leverage obtained by involving all customers and suppliers of energy efficiency products and services, rather than providing subsidies to a select few who may or may not continue to use or provide energy efficiency products and services after the program ends.

Well-designed market transformation programs should produce more energy service choices and better information for customers to use in making energy investment and usage decisions. Over time, market transformation programs should lead to the development of a stronger third-party energy services market and the gradual reduction of some of the most significant market barriers, helping to produce a sustainable market for energy efficiency.

Developing the Market Transformation Approach

Assembly Bill 1890 (AB 1890) requires all customers of the three major investor-owned utilities (IOUs) to pay a small portion of their total electricity bill, ranging from one to two percent, to provide funds for energy efficiency programs from January 1998 through December 2001. AB 1890 establishes a minimum funding level of $228 million per year for the major IOUs, which is significantly below the peak of IOU programs in 1994 ($335 million), but is close to the 1996 spending of $240 million. AB 1890 also mandates that all publicly-owned utilities (POUs) spend roughly $124 million annually on public purpose programs, which include energy efficiency; renewable energy; research, development and demonstration (RD&D); and low-income assistance programs. Preliminary indications from the POUs suggest that $30 to $50 million of the public purpose funds will be spent on energy efficiency programs. In 1994, POUs spent about $90 million on energy efficiency programs. (For our forecasts of how much energy efficiency is likely to be obtained through the AB 1890 levels of funding, see Chapter 12.)

The California Public Utilities Commission (CPUC) has created the California Board for Energy Efficiency (CBEE) to oversee the IOUs' energy efficiency programs for 1998-2001. The CBEE will specify the scope of the programs to be pursued and will evaluate program success. Energy efficiency programs currently run by investor-owned natural gas utilities will also be included within the oversight of the CBEE.. The Energy Commission supports the collection of a surcharge on end-use natural gas customers to support those programs.

Several guidelines should shape the design of market transformation programs:

1. Programs should be tailored to the barriers in specific market segments; there should not be a one-design-fits-all market approach. For example, in some markets it may be appropriate to improve customer information

on model features, life-cycle cost, or performance; in others it may be more important to work with equipment distributors or manufacturers to address product availability, cost, or market development concerns.

2. The goal of all programs should be to produce sustainable changes in energy efficiency markets. Programs that help change the structure of the market should be preferred over subsidy programs.

3. All programs should begin with an assessment that clearly identifies why the current market is not providing appropriate energy efficiency services or products.

4. Programs should include an exit strategy designed to encourage private market actors to provide the programs' services on a for-profit basis in the long term. The end of a program should be triggered either by measured success in reducing market barriers or by the entry of additional private market actors.

5. Programs should include "customer-pull" strategies to increase the demand for efficient products as well as "market-push" strategies (such as standards for buildings and appliances) to increase the supply of efficient products.

6. New programs should be pilot tested to allow for early feedback from market participants and mid-course corrections.

7. Programs should be evaluated in terms of their success in sustaining changes in the market behavior of customers and suppliers. For example, did programs:

   - Increase the level of information available to customers?

   - Increase customer satisfaction with energy services?

   - Help customers assess the performance of different efficiency products or services?

   - Help make new efficiency services or products more profitable to private firms?

   - Stimulate new market entrants?

8. Programs should be coordinated with other efforts such as RD&D and the Commission's Title 20 and 24 appliance and building standards.

The Market Effects Committee of the California Demand-Side Management (DSM) Measurement Advisory Committee (CADMAC) has already started work on evaluation of the market effects caused by existing utility programs. While most utility programs were not originally designed to transform the market, there is some evidence that certain programs have caused significant market effects. For example, commercial lighting programs have caused dramatic changes in the inventory of ballasts available for commercial buildings and in the basic lighting designs offered by building designers. In the residential sector, utility programs have led to the increased availability of more efficient appliances and windows at lower incremental cost.

Chapter 7

RESEARCH, DEVELOPMENT AND DEMONSTRATION

Introduction

For the past several decades, California has led the nation in a wide variety of energy related research, development and demonstration (RD&D) activities, thereby developing and deploying some of the cleanest, most energy efficient and innovative technologies in the world to date. This exceptional RD&D effort has been accomplished through collaboration involving the utilities, the public, and the private sectors. This collaboration has produced valued results and ensured that a wide variety of interests received the benefits stemming from the RD&D. In fact, California citizens now have the opportunity to enjoy the benefits of increased competition in electricity services due in large part to the technological advances achieved through these collaborative RD&D activities.[1]

The development of advanced energy technologies has been and continues to be a centerpiece of state energy policy. It is through such advancements that consumers have the ability to choose from expanded service offerings, while costs and environmental impacts are reduced and reliability increased.

In short, RD&D activities are important tools to be used in helping to achieve the goals of lower, more stable costs, higher consumer value, improved environmental quality, and improved reliability. RD&D also can provide the technical capabilities for consumers to have a wider range of supply and end-use options available from which to choose. The state's RD&D programs advance the state policy to afford consumers the widest possible choices and the ability to make them.

Legislative Mandates and CPUC Decisions

Now, as the state moves toward restructuring of the electric services industry, the California Public Utilities Commission (CPUC) has observed that "[t]he need for [RD&D] activities performed in the public interest will continue in the future, but the role of electric utilities as providers of the services is less clear." (D. 95-12-063; and D. 96-03-022) In preparing for competition, several of the state's investor-owned utilities have already reduced their overall RD&D budgets, while the CPUC has indicated that only RD&D which continues to support "regulated functions" should be funded through rates (D. 97-02-05). Some of the reduction in RD&D funding may be temporary as utilities and others await final outcomes of restructuring, and as new market participants begin to undertake RD&D to become and remain competitive, as has occurred in other restructured industries. However, the long term impact of restructuring on overall energy RD&D efforts should be monitored closely.

The CPUC has also indicated that RD&D activities which serve a "broader public interest...should not be lost in the transition to a more competitive environment." The Legislature has agreed and in AB 1890 has mandated that research, development and demonstration programs that advance science or technology and are not adequately provided by competitive and regulated markets shall be funded at not less than $62.5 million annually from 1998 through 2001[2]. A central feature of this legislative direction is the recognition that California's tremendously successful RD&D infrastructure needs to be nurtured during the transition period in order that it emerge as robust as possible at the beginning of full competition.

A CPUC decision of February 14, 1997, states that the public interest charge authorized in AB 1890 shall be used to fund "public interest" RD&D and not "regulated" RD&D. The CPUC has decided that some previously regulated utility RD&D activities may now more properly be regarded as "public interest" activities after restructuring is instituted.[3] Utilities will have the opportunity to request the Energy Commission reclassify projects from “regulated” to “public interest” so they can qualify for AB 1890 funds.

AB 1890 gives the Energy Commission a major role in administering the public interest RD&D funds, subject to Legislative directions on administration and expenditure criteria. A total of $61.8 million, obtained each year from a surcharge collected by the three IOUs, is to be transferred to the Commission for funding public interest RD&D.

Maintaining Research, Development and Demonstration in a Restructured Market

Aided by an advisory group, the state’s public interest RD&D policy has been refined to address issues raised by restructuring the electricity market. The advisory group met for several months to develop a structure and strategies for implementing the public interest RD&D provisions in AB 1890. The group included representatives from governmental agencies, universities, utilities, equipment manufacturers, environmental groups, and others.

The advisory group proposed a mission and objectives which have been forwarded to the Energy Commission for possible inclusion into recommended administration and spending criteria. The advisory group articulated a mission and set of objectives, and recommended these as part of an overall strategic plan for public interest RD&D. The mission of public interest RD&D should be,

> To conduct research that seeks to improve the quality of life for California’s citizens by providing environmentally sound, safe, reliable and affordable energy services and products. “Public interest energy research” includes the full range of research, development and demonstration activities that will advance science or technology not adequately provided by competitive and regulated markets.

The objectives are more fully described in the Commission’s *Strategic Plan For Implementing The RD&D Provisions of AB 1890*, (May 28, 1997). In summary, the objectives include:

- Develop and implement a robust RD&D portfolio of projects that address California’s energy needs and technology opportunities including strategic concerns.
- Create and maintain a program that balances risks, timeframes, and public benefits.
- Create a knowledge base and disseminate information to allow consumers to make informed decisions.
- Ensure that the public interest RD&D is connected to the market.
- Ensure public input and accountability.
- Ensure efficient administration and stewardship of funds.
- Provide leadership and coordination to support and strengthen California’s RD&D infrastructure by:
  - Collaborating with public and private RD&D entities.
  - Leveraging limited public interest RD&D funds through public/private partnerships to the extent possible.
  - Integrating this effort with other RD&D efforts.

In addition, the Energy Commission believes the following principles should guide public interest RD&D:

- Projects should offer a reasonable probability of providing benefits to those who pay the rate component specified in PUC section 381.

- Projects should provide for improved probability of success or reduced uncertainty associated with a technology or technologies.
- Projects should be balanced among those with short term, mid-term and long term potential.
- Projects should not unnecessarily duplicate research currently, previously, or about to be undertaken by other research organizations.

The Energy Commission will begin to solicit public interest RD&D programs in the fall of 1997. All entities, including utilities, will have the opportunity to propose their public interest RD&D programs and/or projects to the Commission for possible funding.

After the transition period, the restructured environment may be more conducive to privately funded RD&D because those who innovate will be better able to capture market share, and those who do not innovate will likely lose market share. Government's role will include insuring that those who can innovate receive the benefits and have open access to a market within which to achieve those advantages.[4] Another important role is to reduce the risk of investing in RD&D through a variety of mechanisms such as: leveraging funding, maintaining realistic market policies, reducing regulatory and institutional barriers, and disseminating information.

The Energy Commission will use several methods in meeting this role.

1. As discussed in Chapter 12, the Commission will continue to improve the power plant siting process; in so doing we will encourage the market introduction of successful RD&D efforts in generation. The Commission will use its current authority to grant a notice of intent (NOI) exemption under Public Resources Code (PRC) section 25540.6 for appropriate projects.

2. The Commission will coordinate efforts to develop 'model codes' to simplify, on a state-wide basis, the permitting of new technologies such as electric vehicles or small distributed generation. This might relieve monitoring and permit burdens on local air districts and building officials, which would otherwise be faced with an increased administrative burden. We will continue our efforts to work cooperatively with districts through the Air Quality Forum we initiated in the ***1994 Electricity Report (ER 94)***.

3. Further, the Commission will foster stakeholder involvement and lead in creating public private partnerships and coalitions, acting as a catalyst. One primary example of this type of activity is the California Alliance for Distributed Energy Resources (CADER).[5] We will follow the example of CADER and create a public-private coalition to accelerate development and introduction of advanced metering and communication technology.

4. The Commission will develop and recommend use of appropriate incentives which account for public costs and benefits of advanced and traditional technologies not reflected in market prices. The Commission will also develop non-monetary measures to overcome market, regulatory, and institutional barriers to commercialization

In addition to actions the Commission will undertake, the participation of outside parties will be critical. The Commission recommends:

Some technologies, such as end-use technologies that result from successful public interest RD&D will not require siting or permit facilitation. The public interest RD&D for end-use technologies will need to be coordinated with market transformation activities in energy efficiency markets. (For additional discussion on market transformation for energy efficiency, see Chapter 6, Energy Efficiency.) The Commission will continue to cooperate with the CPUC and the newly formed Independent Energy Efficiency Board (IEEB)[6] to ensure that markets are receptive to emerging end-use technologies. Similar cooperation between RD&D efforts and renewable market development efforts is needed.

The Commission also anticipates expanding the involvement of stakeholders and expert advisors in planning and implementing publicly funded RD&D programs in order to avoid unnecessary program overhead costs and, importantly, to insure that public interest RD&D projects are connected to the market. This should include policy and corporate level decision makers in addition to researchers.

Finally, the Commission will place greater emphasis on facilitating the marketing of successful RD&D programs. The Energy Commission has for years helped California companies export products and services to the international market place. Originally developed because California electricity markets were 'saturated' and little opportunity existed for the nascent independent power industry, the program should be expanded to augment the market opportunity for new technologies. With expanded market potential, research, development, and demonstration programs become more certain from an investment perspective. We anticipate that the program may be able to leverage additional private RD&D, by facilitating access to expanded international markets.

While RD&D is of great importance, alone it is of limited economic or environmental significance. The contribution of RD&D to the state's economic performance and environmental vitality depends on how well firms can utilize and commercialize results to bring about profitable new products and processes. A significant role for government, and an important aspect of the state's RD&D policy, is to address market barriers and to ensure the effective transfer of technological knowledge. Technology transfer includes many forms: among researchers, from researchers to developers, and from developers to various types of consumers. Technology transfer is critical in ensuring that citizens, businesses, and other entities have advanced products from which to choose and can make informed decisions concerning energy technologies and services.

In addition to technology transfer between scientists and researchers, consumers of all types will need information and education to evaluate an expanding set of technological options. The Commission will continue working with private and public concerns to help in the critical market education function. One way the Commission expects to assist in this regard includes expanding our web-site "Access Energy."

Endnotes

1. Such benefits are to be expected from RD&D. Studies of the benefits from products and services developed through RD&D indicate that the return to society as a whole has been very high, on the order of a 50 percent average annual rate of return, about twice the average private rate of return to those who make the RD&D investments. (Mansfield, E., and others, Social and Private Rates of Returns from Industrial Innovations, Quarterly Journal of Economics, 91 (May), pp. 221-224**.**
2. PUC section 381 (c) (2).
3. D.97-02-014 provided that transmission and distribution RD&D associated strictly with the regulated functions of the utility remain a regulated RD&D effort.
4. This means that issues of market power associated with entrance, as opposed to pricing, can affect the deployment of innovative technologies, and should be avoided.
5. The approach and efforts of the CADER are described in Chapter 9, Distributed Resources, which discusses distributed resources benefits to California.

6. The IEEB was created by the CPUC and is described in Chapter 6, Energy Efficiency, which discusses changes in the planning and administration of programs to encourage increased cost effective energy efficiency.

Chapter 8

RISK MANAGEMENT AND DIVERSITY

Introduction

California is committed to diverse electricity supply options. The Legislature has declared that "a principal goal of electric and natural gas utilities' resource planning and investment shall be to encourage the diversity of energy sources through improvements in energy efficiency and development of renewable energy resources, such as wind, solar, biomass, and geothermal energy " [Public Utilities Code (PUC) Section 701.1(a)], and in AB 1890 the Legislature stated its intent “to ensure that California's transition to a more competitive electricity market structure . . . preserves California's commitment to developing diverse, environmentally sensitive electricity resources" [AB 1890, Section 1(a)]. The state's diversity policy is based on two key provisions: (1) if one type of generating technology or fuel source is experiencing price or supply disruptions, customers with alternative supply sources available can moderate those effects; and (2) a diverse supply can reduce the environmental risks of a single-source generating system.

Thus diversity is not a goal itself, but is rather a means to the goals of price stability, supply reliability, and improved environmental quality. Diversity is but one of several tools that can be used to reduce the risks inherent in the production and distribution of electricity. In a competitive market consumers will have new opportunities to manage the risks of price volatility and reliability-threatening supply disruptions -- and new challenges in those areas. This section discusses how the competitive market will change risk management options and who can use these options. Diversity's role as a risk management tool is then examined, and finally the funding allocated by AB 1890 for development of renewable resource technology is discussed.

Risk Management

In the current regulated, monopoly utility system, utilities have an obligation to provide and deliver power to all consumers in their service territories, at rates set by government. One goal of regulation has been to ensure the reliability of supplies and to shield consumers from undue price swings. In addition, in the current system most residential and commercial customers pay a monthly bill in which the price of electricity is averaged over the entire billing period even though the cost of producing the electricity varies significantly by the day and by the hour. As a result of those factors, many consumers have grown accustomed to a system that has masked risks and promoted stability -- perhaps at the cost of higher prices than would have been paid in a competitive market. In a competitive market, the utilities will have only the obligation to provide distribution connections to the grid (that is, to ***deliver*** power); no one will have an obligation to ***generate power***, so consumers will be responsible for choosing their own power sources. Customers will be faced with prices that vary considerably during the course of each day. Thus, consumers themselves will become responsible for obtaining protection against undesired short-term and long-term price swings and against reliability failures.

The good news is that in a competitive market a variety of risk management tools are likely to be available. Moreover, the competitive market will allow consumers to pay only for those price and reliability guarantees that they find valuable, instead of the one-size-fits-all approach in the current monopoly system.

For many consumers, price will be paramount. Some may want to protect themselves against unexpected Power Exchange (PX) price increases due to a rise in fuel costs, in which case a long-term, stable, price contract with a direct access provider could be the answer. Such a contract would shift, perhaps for a premium, the risks of price increases from the consumer to the direct access supplier. If the goal is to protect against the daily or seasonal price spikes at times of peak demand, a consumer may agree on a contract with a supplier that charges a rate slightly higher than the standard rate, but that remains constant throughout the year.

Reliability is a second area in which consumers may seek to manage their risks. Consumers for whom reliability is critical, such as computer chip manufacturers, can be expected to willingly pay a premium to suppliers who will provide back-up power or who will guarantee to cover losses incurred if power is not available.

Various risk management tools used by companies and individuals may only shift risk among members of society, benefiting those companies and individuals but not reducing overall societal risks. Providing options for the cost-effective reduction of societal risk is a public policy issue that government should address. During the transition period from 1998 through 2001, the Energy Commission should, and will, monitor the success of the market in providing adequate risk management tools and assess whether there is a need for government action if the market is not providing adequate risk management tools to consumers.

Diversity

As a result of policies promoting diversity, the electricity system in California today is as diverse as any system in the world with a wide range of generating technologies, fuels, and fuel sources. Compared to 20 years ago, dependence on conventional sources -- large fossil-fired power plants -- has been reduced, the environmental effects of those facilities have been lessened, and a new renewable energy industry has been created in the state. Consequently, there are more options today from which to choose.

It is important to recognize that diversity is more than just renewable generation technologies. It is a variety of factors including the number of different fuels, technologies, and suppliers available, the relative shares of each fuel and technology in the market place, and the correlation of prices between the different fuels and technologies. Moreover, while diversity of fuels and technologies is important, so is having multiple sources of the same fuel. For example, California has pipeline capacity and market access to at least four natural gas supply regions, thereby increasing the price stability and reliability of that fuel.

The restructuring of the electricity industry will not change the basic goals of diversity, but it will change the mechanisms to maintain a diverse electric system. In the restructured world there will be greater need to evaluate the costs of diversity in comparison to the benefits. In the past, diversity has meant reducing the fossil-fueled generation by increasing the amount of renewable generation technologies. Due, however, to the relative newness of many renewable technologies and the terms of the standard offer contracts available to renewable generators from California's utilities, renewables sources have had higher costs than other power plants. Now, production costs of maturing technologies have come down and the terms of utility contracts with many renewable generators are changing. During the transition period, state government should undertake a thorough assessment of the costs and benefits of diversity. This assessment, already begun by the Energy Commission staff, should include development of a "diversity index" to measure the level of alternatives afforded to the market as well as development of a cost-benefit methodology.

AB 1890 Funding for Renewable Resource Technologies

AB 1890 has confirmed the state's support for renewable resources by requiring the investor-owned utilities to collect $540 million in rates from January 1998 through March 2002 for the support of renewables. (PUC Sections 381, 383.)[1] The funds are to be spent for the purposes of "[s]upporting the operation of existing and the development of new and emerging in-state renewable resource technologies," expressly including support for existing solid-fuel biomass and solar thermal facilities. [Public Utilities Code Sections 383(a)(1)-(3)]. The Commission has made recommendations to the Legislature on the disbursement of the funds using market-based mechanisms. The funds are to be allocated between both "new and emerging" technologies and "existing" technologies, with no less than 40 percent for each category.

The most desirable result of spending up to $540 million of IOU ratepayer money over four years would be the development of a self-sustaining renewable electricity market. Such a market will develop if a sufficient number of renewable power sources become cost-competitive with conventional sources, or if a sufficient number of consumers are willing to pay a price premium for renewables. One of the key benefits of a free-market system will be that consumers can select the types of power that they want; we fully expect that many power marketers will make "green power" available to consumers who are willing to pay for it. A green pricing program could enable retail electric power customers to pay the incremental cost of obtaining part of their electric service from technologies that are environmentally preferable or by allocating funds toward the purchase of environmentally preferable power facilities.

In order to ensure that consumers have accurate information about the electricity sources they choose, a new law -- SB 1305 -- was enacted in September 1997. It requires that all sellers provide to residential consumers information in a standardized format on the fuels used to generate electricity. The bill requires the Energy Commission to provide guidelines for the consumer disclosures, collect generation information, and verify the fuel sources disclosed. (The Commission will use generation information already supplied to the Independent System Operator.) The bill also calls for an analysis of the air emissions associated with the new electricity market, to be provided to the Legislature in July 1999.

Further government-mandated support of renewable energy sources after the AB 1890 funds run out in 2002 should be based on considerations of economic efficiency. The economic, reliability, and environmental benefits of a system with few sources and potentially lower costs should be compared to a more diverse but potentially more expensive system. In addition, consideration should be given to whether a specific diversity policy has sufficient breadth to mitigate risks from unanticipated events as well as known or perceived risks. Diversity should be supported by state government if the potential benefits of a more diverse system can be shown to outweigh the higher costs of that system. While some costs and benefits cannot yet be quantified, the analysis of costs and benefits is nonetheless important.

Endnotes

1. AB 1890 also requires the Public Owned Utilities (POUs) to collect funds for the joint purposes of energy efficiency, renewable energy technologies, RD&D, and low-income-customer assistance. The POUs can decide how the funds are allocated; thus it is possible that one POU could spend all of its funds on renewables and another POU could spend none. (PUC Section 385.)

Chapter 9

DISTRIBUTED ENERGY RESOURCES

Distributed Energy Resources (DER) are small electricity generators or storage devices located close to load centers or at customer sites. Although the term Distributed Energy Resources is a recent coinage, its application is common practice. The best known applications are emergency diesel generators at hospitals and around-the-clock manufacturing firms that require an uninterrupted power supply.

Distributed Energy Resources have several potential advantages when compared to large, conventional power plants:

- DER are much smaller and require little space. Conventional power plants usually occupy several city blocks, while DER can fit atop the roofs of office buildings and shopping malls, or under freeways and light rail tracks. They also can be portable, mounted on trucks or railroad cars to be transported to the location needed for a time, and then moved.
- Some DER, such as fuel cells and photovoltaic technologies, produce little or no air emissions and require little or no water during operation.
- DER can economically provide power where voltage sags and frequency dips occur in distribution systems, thereby avoiding damage to sensitive manufacturing devices or test equipment.
- DER require lower total capital expenditures than conventional power plants, although they are unlikely to have the advantage of economies of scale.
- DER may enjoy a faster permitting schedule, especially where there is strong community opposition to large, new power plants.
- The use of DER obviates or defers the need to construct additional or upgraded transmission lines for power distribution.

Distributed Energy Resources do, however, raise several issues. The most important is that gas-fired DER may produce cumulative emissions that exceed standards set by local air districts, even though individually many DER are substantially cleaner than existing combustion technologies. And yet many DER are below the jurisdictional threshold of local air districts and are thus at this time essentially unregulated. In addition, because of their small generating capacity, under current law most DER will be licensed at the local government level; only those power plants of 50 megawatts or more are licensed at the state level. Local governments, however, may be unfamiliar with distributed resources or lack the analytic tools to assess potential impacts.

The future use and market penetration of DER is uncertain at this time. DER does hold promise in advanced, lower-polluting, higher-efficiency technologies, such as the smaller 5-to-20 megawatt gas turbines, the 50-to-500 kW microturbines, photovoltaics, fuel cells, batteries, flywheels, and Superconducting Magnetic Energy Storage (SMES) devices. How quickly DER becomes a substantial part of California's electricity generation system in this new era will primarily be determined by its economic competitiveness in each market niche.

The future may see the widespread use of rooftop photovoltaic systems, fuel cells, and small microturbines that supply residences and small commercial users with virtually all their energy needs. More efficient electrical storage systems and hybrid cars that generate electricity when not being driven could revolutionize the electricity industry. The need for new bulk transmission lines may be virtually eliminated and the primary purpose of the distribution system may be to handle local imbalances between supply and demand.

To assist the continued development of DER in California, the Energy Commission will continue its involvement in the California Alliance for Distributed Energy Resources (CADER), an organization of more than 125 government agencies and industrial, financial, research, and manufacturing companies. CADER's mission is to remove regulatory and institutional barriers to DER by anticipating, rather than reacting to, the need for changes. CADER will develop a public education program, make recommendations for permit streamlining, and advance DER research and development. The collaborative seeks to have action plans completed in the fall of 1997.

Chapter 10

INFORMATION NEEDS IN A COMPETITIVE ENERGY SERVICES MARKETPLACE

Introduction

Markets work efficiently only when reliable information is widely available. Unfortunately, competitive markets do not, in practice, operate with the "perfect information" assumed by economic theory. Competitive markets tend to restrict information flows among competitors and between suppliers and consumers. Moreover, in the regulated electricity market the essential information flows have been fully internal to monopoly utilities or have been structured for a non-competitive environment, and it will take time for the information flows to change. As a result, many parties, particularly small customers, may not be able to depend on the marketplace to provide the information needed for efficient market performance, especially when retail competition begins in 1998. Government agencies, which frequently collect and disseminate information to ensure that market participants can make well-informed decisions, will have an important role to play in this area; for example, the Energy Commission collects, aggregates, and distributes information about the petroleum industry, which helps competitors evaluate supply and demand trends and make investment decisions.

Restructuring of the electricity industry will substantially change the types of information needed and who needs it. For example, while several autonomous utilities currently make generation-dispatch and transmission use decisions, the new Power Exchange (PX) and Independent System Operator (ISO) will assume those duties for a highly-coordinated system under restructuring. Another major change will be that some utility monopoly functions will be subject to competition. As the electric industry is restructured, reliable flows of information will be essential for:

- Informed consumer decision making
- ISO, PX, California Public Utilities Commission (CPUC), Investor-Owned Utility (IOU), and publicly-owned utility (POU) coordination of the operations of the generation, transmission, and distribution systems
- The business activities of generation suppliers, wholesale marketers, and retail energy service providers
- The market monitoring, oversight, and environmental and consumer protection activities of government

With regard to the last item, the traditional utility-regulator relationship will still generally apply to transmission and distribution, and therefore detailed operational and financial information on those functions will still have to be provided to government agencies, although the content of information required will change as new regulatory paradigms, such as performance-based ratemaking (PBR), are implemented.

Of course, the industry is still at an early stage in the evolution of the competitive energy services market. The roles and activities of various players will evolve in response to policy decisions at the state and federal levels, technological innovations, and other developments. Therefore, information management arrangements implemented today will need to be adaptable. In addition, because information technology can represent a massive investment in hardware and software, a careful balance needs to be struck between, on the one hand, capturing economies of scale and scope and, on the other hand, minimizing the possibility that new systems will create new monopolies and thus preclude desirable competition for information-related products and services.

In addition to the availability of information, the ownership and transfer of electricity information is an area that will need government attention. Who owns electricity information is often unclear, and even if ownership could be assigned there would still need to be restrictions on the use and dissemination of the information for privacy and other consumer protection reasons.

Given all the above factors, the Energy Commission has emphasized a comprehensive, forward-looking approach. Institutional arrangements should be the focus of information decisions for the long-term. That is, rather than try to decide all the details now about how information flows should be managed in the mature market, policy makers should facilitate the creation of organizations and processes that can make good decisions at the time they are needed. In addition, given the potential for conflicts among parties over the control of information and the need to avoid creating new, inefficient monopolies, stakeholder participation on a continuing basis should be a key element of information management in the mature market.

Information Needs of the Competitive Marketplace

Wholesale Generation and Transmission Markets

With unbundling of the generation and transmission functions, wholesale generators and marketers will be interacting with the PX, scheduling coordinators, and the ISO. These new institutions and market players bring with them distinct information needs.

Formal arrangements for information flows between suppliers, the PX, and ISO were developed in the IOU’s Phase I and Phase II filings to the Federal Energy Regulatory Commission (FERC), which spell out the rights and obligations of market participants. A "WEnet" will be established to provide public, non-discriminatory access to information concerning the status of the ISO grid and the PX by a wide-area system similar to the Internet. The WEnet will provide information such as demand, prices, and congestion. In general, the ISO and the PX would keep specific bid data confidential. We believe the proposed treatment of information for the ISO and PX is appropriate in that it provides the necessary information on aggregated system characteristics to all parties, while it allows contract information to be kept proprietary and disclosed only at the discretion of contracting parties.

Generation is the primary area in which existing monopoly utilities will become players in new competitive supply markets; they also will begin competing in retail energy services. To the extent that those utilities (or their affiliates) begin competing and have information available only to them, that information should be made available without charge to new suppliers, at least during the transition period. (Both FERC and the CPUC are developing utility affiliate transaction rules. CPUC Decision 97-05-040 requires utilities to release customer information to an Energy Service Provider (ESP) upon receipt of a written request from the customer and a non-confidential database of customer-specific information to be made available to ESPs.)

As the market becomes transformed, information development should be increasingly the responsibility of market participants. Where utilities or their affiliates are not participating in a particular market, the participants in that market should be required to develop or purchase the data they need (including purchasing it from utilities) and not be given the information by the utility, because all competitors will already be on a level basis.

Retail Marketplace Suppliers

Firms operating in the retail marketplace need two basic types of information: demand and supply. Demand includes everything about consumers -- their energy end-uses, needs and preferences, decision making criteria, and behavior. Most individual information is gathered as a normal part of the business of supplying electricity, through sign-up, metering and billing activities. Other individual information may be gathered through surveys, energy audits, and acquisition of other databases. Aggregate level information may be created by aggregating individual information, or through the use of models, economic statistics, and other standard research techniques. Retail firms can do market research using non-personal information, but direct marketing requires customer identification and contact data, which raises concerns about protecting customer privacy.

Supply information includes descriptions of the products, services, and energy supply contracts being offered, as well as descriptions of the firms themselves and the customer groups they are targeting. Some of this information would be gathered by government as part of its monitoring and oversight functions, some by industry associations, some by independent consumer-oriented services and other non-profit organizations, and some by the firms themselves as part of their market research.

Information for Load Scheduling and Bidding Payments

Customer metering data has long been used by the utilities for billing customers and to fairly allocate consumption and distribution costs; the utilities were the only entities with access to the data. In the competitive market, end-use customer data will also be needed for load scheduling and for payments to generators making bids, and thus several different suppliers will need the data. Moreover, private parties will start to provide metering and billing services, so the data will be in the hands of several different entities. The combination of more parties needing the data and fragmentation among the parties having control over the data will make it difficult to ensure that appropriate data is available and is of high quality.

A Central Database?

One potential solution to several information issues at both the wholesale and retail levels would be to create a central database. For example, many parties will need access to end-use meter data. One way to accomplish this is to allow multiple parties to interrogate the meter directly to obtain the raw data. An alternative is to create a central database that would collect all the raw data, and to allow multiple parties to have access to the database.

The central database approach would use less costly meters, provide security, and simplify access to aggregate data for market monitoring and research.

The idea of a central database that maintains end-use data on all customers, however, raises serious concerns about how such an entity would be governed. Restructuring that is de-integrating the large electric monopolies should not create a new information monopoly, or a new and complex government bureaucracy. For the near-term, it may be most natural for the utility distribution companies (UDCs) to create an open-access database for end-use meter data, as they will probably want to have this data for all their distribution service customers. Yet many parties are concerned that a decision to grant that responsibility to UDCs for the near-term could secure a data monopoly for them in the future. Clearly, then, near-term arrangements must be designed with the flexibility to adapt as the marketplace evolves.

Consumer Needs

Energy consumers will need ready access to information about the market and about their own energy use and needs. Customers will need trustworthy information about the products and services available, and will need tools to help them evaluate and compare different products and services. Information will need to be readily understandable to consumers, so that they can be confident they are choosing the services they really need and are receiving the services they have chosen and paid for. Hence, they also must be able to understand their own energy requirements and service needs so they can know what to look for in the marketplace.

AB 1890 requires energy suppliers to provide information on the price, terms and conditions of offers they make to consumers. Government should strive to minimize interference in the competitive market, but it should also seek to assure that information is truthful. Nothing destroys markets more than misleading or inaccurate claims that poison consumer trust.

Government Responsibilities

As the electricity market transitions to effective competition, the information needs of government will change. Government's role will focus more on monitoring, oversight, and consumer education and protection and less on market regulation and planning. Government agencies, including the

Energy Commission, will need information to carry out ongoing responsibilities to:

- Monitor and assess market performance in order to avoid significant market failures and potential abuses of market power.
- Ensure the continued reliability of the state's electricity system.
- Remove barriers to competitive markets.
- Implement public policy objectives.
- Ensure market participants have information necessary to make informed choices

The most important new function for government in the competitive market will be to prevent or ameliorate market failures or abuses if they occur. Careful monitoring and analysis will be needed of the activities of the various industry participants, most crucially during the transition years. Just as the need for market monitoring is increasing, however, the traditional sources of such information are shrinking. The utilities are reducing their collection of energy data and, at the same time, are becoming less willing to release the data they continue to collect. The Strategic Plan recently adopted by the Energy Commission and approved by the Governor calls for the Energy Commission to be responsive to the market in information collection and dissemination. Delineation and implementation of the Commission's functions will occur in a current rulemaking, which will eliminate unnecessary requirements, ensure that information necessary in the restructured market is obtained, and protect legitimate privacy interests. In addition, the CPUC is assessing how much customer information the IOUs should disclose, and how to protect customer privacy.

Market power monitoring goals are threefold: to identify if changes in the ground rules are desired, to deter potential market power abuse, and to detect abuse when it occurs. Monitoring will both evaluate the progress of the new market towards becoming more competitive and police operations for the abuse of power. It should be designed to be non-intrusive, to focus on activities outside of a band of acceptable market practices, to rely as much as possible on data collected for other purposes, to protect confidentiality concerns, and to be cost-effective.

With regard specifically to the Energy Commission, information services that we currently provide will continue to support the ability of policy makers, business interests, and consumers to make informed choices: providing timely, reliable, and independent analyses of energy supply and demand trends, energy markets, energy systems operations, environmental impacts, and other issues of concern to California's economy and environment. Information about the future demand for electricity, particularly the intermediate-term (three to seven years), will be especially useful in an era of shorter lead-time power plant investment and business decisions. Forecasting of future loads and incremental additions will be important for the physical and business functions and entities within the electricity marketplace -- the UDCs, ISO, PX, and retail energy service providers (ESPs) -- to plan improvements and additions to the transmission and distribution systems.

Among the most important of the Energy Commission's data needs is a complete database regarding energy consumption and fuel use. Under the utility monopoly structure, utilities collected this type of data from their retail customers, and regulatory agencies have permitted utilities to recover the costs of conducting data-collection activities. However, the recent CPUC decision to "defund" utility demand-side management (DSM) programs (pursuant to AB 1890's direction to establish non-bypassable surcharges for public-purpose programs) also removes funding from data collection programs upon which both the utilities and the regulatory agencies have depended. Those important data collection activities should continue.

The data that all market participants are dependent upon must be accurate, of high quality, and secure from inappropriate manipulation. In addition, there should be adequate dispute resolution mechanisms to solve problems as they arise. Auditing of end-use customer data, from meter measurement through final bill computation, may be one element of such mechanisms; stakeholder technical arbitration panels may be another. Government and industry are working together now to create mechanisms to insure that all parties can rely on customer data as one of the foundations of the competitive market.

Information Privacy and Proprietary Rights

The transfer of confidential information among various entities -- individual and corporate, public and private, regulated and unregulated -- raises issues regarding the rights and responsibilities of all parties involved, whether as subjects, collectors, custodians, developers, or users of information. The issues are all variations on a common theme: the right of one party to limit access or to receive compensation for access to certain information, versus the right of another party to have access to that information on reasonable terms. There also may be a third party that possesses the information and may have some responsibility for ensuring the rights of the other two parties. The role of government is to ensure that the entities that possess confidential or proprietary information follow rules and respond to incentives that support the legitimate needs and concerns of all parties.

Consider utility customer records, for example. The electric utility maintains a record for each customer containing the customer's energy usage and bill payment history and other demographic and energy-related information. Collecting and maintaining such information have always been essential elements of providing electric service, and the utility has held all such information confidential on the grounds of customer privacy. Use of customer information for competitive purposes was simply not an issue when the industry was not competitive. But now ESPs want to market their services to the utility's customers, in direct competition with the utility itself. If only the utilities have access to customer records it could seriously impede the development of a competitive direct access marketplace.

Privacy Rights

Under the California Constitution, individuals are guaranteed a right to "informational privacy," which prevents government and businesses from collecting unnecessary information about individuals and from using information gathered for one purpose to serve other purposes. Nonetheless, the erosion of personal privacy is a high-profile issue that encompasses most sectors of the economy. From the experience of telephone deregulation, most consumers are already aware of marketing practices such as sales calls during the dinner hour and "slamming" (switching a customer's service provider without authorization). Preventing such abuses in electric industry restructuring is a high priority for policy makers.

Business customers are concerned about privacy from a different viewpoint: knowledge of their energy usage and costs may be of strategic value to their competitors. Businesses are not covered by the constitutional right to privacy guaranteed to individuals, but businesses can generally protect such information under trade secret statutes.

Customer privacy can be protected by obtaining customers' consent to use the information for a specific purpose or to release it to other parties. In the regulated electric industry, consent was obtained by requiring written authorization by the customer to release information to a specific third party, on a customer-by-customer basis. In the restructured market, where information on large numbers of customers is proposed for release to facilitate market participation by new competitors, the two basic ways to obtain consent are the "opt-in" and "opt-out" procedures. Under both procedures, customers are informed about the intent to release information and are given no-cost ways to respond. Under an opt-in procedure, also known as a "strong consent" requirement, customers are asked to give explicit permission to release information; customers who do not respond are not included in the released data set. Under an opt-out procedure, also known as a "weak consent" requirement, customers must explicitly deny permission to release their information; customers who do not respond are included in the released data set. Experience in other contexts indicates that most customers do not respond to either type of procedure. Of course, the opt-out procedure places greater responsibility on customers to read and respond to notices in order to protect their own privacy, and requires confidence that a customer's opt-out response will actually be received and recorded by the information custodian. In practice, the choice of consent mechanism should be matched with the sensitivity of the data.

Proprietary Rights

All firms collect information about their customers in the course of doing business. In a competitive industry such information is normally considered an asset of the firm and is protected under the rules governing trade secrets. (There may still be some restrictions on the firm's use of that information, however, particularly where customer protection issues are involved.) For the restructured electric industry, it is not clear to what extent utility shareholders and ratepayers should be compensated for commercially-valuable information that has been previously or is currently collected at ratepayer expense, and maintained by the utility and that may soon be required to be released to other private firms. To make the matter even more complicated, the argument is arising here and in other industries that information about customers is the property of the customers themselves, and that therefore customers should be paid for the use of that information. Recent research has shown that customers may be less concerned about privacy considerations if they receive some direct economic benefit from the sale or use of information on their behavior as consumers. Legislative action may be needed here.

Chapter 11

PUBLICLY-OWNED UTILITIES

Introduction

California's publicly-owned utilities (POUs) provide electric service to approximately one-fourth of the state's population. Varying markedly in size and in the types of customers they serve, there are 27 municipal utilities, 8 irrigation districts, 3 rural electric cooperatives, and 10 other federal, state, and local bodies. Some sell to retail customers, some at wholesale, and some both. Of those that sell power to retail customers, 11 serve fewer than 10,000 customers, 11 others serve between 10,000 and 50,000 customers, and 10 have more than 50,000 customers. Ten POUs own electric generation facilities, and many own or have rights to parts of the bulk transmission system.

Throughout the restructuring process, the following issues have been the most important to California POUs:

- Participation in the Independent System Operator (ISO) grid, direct access for POU customers, and the reciprocal ability of POUs to sell to Investor-Owned Utility (IOU) customers
- Recovery of stranded costs
- Public interest programs
- Transmission fees

AB 1890 and recent Federal Energy Regulatory Commission decisions have resolved most of those issues.

POU Participation in the ISO

Assembly Bill 1890 (AB 1890) states the Legislature's intention that the state's POUs, as well as the IOUs, give control of their transmission facilities to the ISO. It also states that the IOUs and POUs should jointly advocate an equitable transmission pricing mechanism to FERC.

In support of the Legislature's "intent" that the POUs join the ISO system, the statute expressly requires that the ISO governing board contain representatives of POU transmission owners. (AB 1890 also requires that the Power Exchange (PX) board include POU representatives.) It also contains a powerful incentive for the POUs to join: no POU (or IOU) may impose a competition transition charge (CTC) unless the utility has committed control of its transmission facilities to the ISO. For transmission-owning POUs with substantial stranded costs, AB 1890 may create irresistible economic pressure to join the ISO system. The Energy Commission supports the generally-accepted view that it is desirable for the greatest possible number of participants to turn over control of their transmission systems to the ISO, based on the premise that both operational and economic efficiency are likely to be maximized under those circumstances.

In general, the POUs want to participate in the ISO grid. However, because the POU transmission network has been financed with tax-exempt bonds, there is some doubt whether the facilities can be turned over to the ISO. Such action could be considered “private business use” of the facilities, which would make them ineligible for tax-exempt financing. The IRS will rule on the matter soon. Moreover, the POUs continue to have problems with ISO-proposed transmission access charges.

When the ISO adopts reliability standards for transmission facilities, participating POUs will be subject to the standards and to sanctions for violations.

Direct Access for POUs and Their Customers

AB 1890 does not require POUs to allow its customers to have direct access to competing suppliers, but it directs each POU to determine whether to allow its customers to have direct access. If a POU decides to allow direct access, a phase-in must take place between the years 2000 and 2010.

The Energy Commission believes that most POUs will decide to allow direct access. When alternate suppliers begin to offer lower competitive rates, some POU customers can be expected to demand access to them. Since some POUs' industrial rates are only marginally competitive with IOU industrial rates, the pressure is likely to be most intense from those customers. Another powerful incentive for direct access is AB 1890's command that POUs may not collect a CTC unless they authorize direct access. For those POUs with substantial stranded costs, allowing direct access may be a financial necessity.

The Energy Commission supports the principle that all California electricity consumers should have full access to the competitive market. We urge POUs to allow direct access, on schedules that are appropriate for each individual POU's customers and financial circumstances.

AB 1890 contains two important provisions on direct access. First, it ensures that any IOU or POU customer electing direct access from another supplier, whether another utility or an independent producer, must pay its original utility's CTC before it can begin receiving direct access service. Second, if a POU decides to allow direct access, AB 1890 allows it to act as an aggregator, combining loads of different customers to facilitate the purchase of electricity. If a POU, however, or any other public agency, serves as an aggregator of residential customers, it must offer to include within the aggregated group all residential customers within its jurisdiction.

An important consideration for direct access is "reciprocity." Reciprocity is the principle that utility A is to be given access to utility B's customers only if utility B is given direct access to utility A's customers. The California Public Utilities Commission's December 20, 1995 restructuring decision stated that the CPUC would not require the IOUs to tolerate the formation of bilateral contracts between customers within their own service territories and POUs unless the POUs extended reciprocal rights to IOUs. It is not clear what entity will enforce the CPUC's principle. While IOUs favor ISO enforcement, POUs have suggested that enforcement duties could conflict with resolution of transmission disputes. Additional concerns remain about potential inequities that could arise when out-of-state power suppliers acquire direct access to sell power to California customers without the burden of an interstate reciprocity process that would allow California suppliers direct access to the out-of-state customers.

The Energy Commission supports the general principle of reciprocity embodied in the CPUC's decision, because it is consistent with the principle of maximum consumer choice and with the Energy Commission's support of direct access. Additionally, development of interstate reciprocity guidelines consistent with Federal constitutional limitations could facilitate California power suppliers' access to the customers of out-of-state suppliers selling to California customers. At this time, however, the Commission does not recommend or endorse any particular mechanism to enforce the reciprocity principle, because there is as yet insufficient evidence to support a particular means of enforcement as superior.

Actually, reciprocity may prove to be unenforceable, because use of the PX could provide all the economic benefits of physical direct access through contracts for differences (CFDs). A supplier and consumer with access to the PX would agree to a bilateral contract containing any price and other terms the parties freely chose. The supplier would then bid its power into the PX. If the supplier's bid were accepted, the supplier would receive the Market Clearing Price (MCP) from the PX, while the consumer would pay the MCP to the PX; whenever the MCP was above the contract price, the supplier would rebate the difference to the consumer, and whenever the MCP price was below the contract price, the consumer would rebate the difference to the supplier. In either case, the parties would receive the benefits of their contract price. If the supplier's bid were too high for dispatch by the PX, the consumer would still receive its power from the PX at the MCP; any difference between the MCP and the contract price would be rebated between the contracting parties, again leaving them with the benefit of their contract price. Thus, even if the ISO (or other enforcement entity) had already denied physical direct access to a utility because that utility had failed to allow another supplier access to its traditional customers, the alternative of "virtual direct access" through a CFD would nevertheless be available to the denied utility.

A potential problem for POUs desiring to sell outside their service areas is the "private business use" restriction discussed above with regard to POU participation in the ISO grid. Current IRS rules would prevent more than 10 percent (or $15 million, whichever is less) of the output of a POU power plant financed with tax-exempt bonds from being sold to private entities. Even sales to the PX may run afoul of the prohibition.

Recovery of Stranded Costs

AB 1890 authorizes POUs (as well as IOUs) to establish a CTC to recover their own stranded costs. Thus even a POU customer who chooses a different power supplier (but who continues to receive distribution service from the local POU) will pay for that POU's stranded costs, if there are any. AB 1890 contains no limitation on how long the POUs may collect a CTC; thus CTC collection by POUs can extend beyond the four-year period from 1998 through 2001 authorized for the IOUs' CTC recovery.

The obligation to pay the CTC does not apply to 110 megawatts of irrigation district load, as allocated by the Energy Commission (at least half of the allocation must be for agricultural water pumping); to 75 megawatts of load served by the Merced Irrigation District; and to the power used for water pumps owned by various agencies that were, on December 20, 1995, members of the Southern San Joaquin Valley Power Authority or the Eastside Power Authority.

As a result of those exemptions, current customers of utilities with stranded costs who are within an irrigation district (or as otherwise provided by AB 1890) may choose the exempted entities as their new power suppliers and avoid paying the CTC to the old utilities. The vast majority of such customers will come from PG&E, within whose service territory most irrigation districts are found. The CTC exemption given to the irrigation districts will provide them with a substantial advantage in competing for new customers when direct access becomes available.

As with IOUs, the amount of stranded costs that the POUs will have depends on the market price that the POUs will receive for their power **--** a higher market price will mean lower stranded costs, and vice-versa. If the market price averages 2.4 cents/kWh (our most current estimate), then LADWP and SMUD are likely to have quite substantial stranded costs. How much of a CTC will have to be imposed to recover those costs depends in turn on how quickly the costs are recovered. **Table 11-1** below shows our estimates of (1) the net present value of stranded costs for the three largest POUs (assuming a 2.4 cents/kWh average market price) over the 1997-2007 period (we ended the analysis in the year 2007 because after that the POUs are likely to renegotiate current contracts) and (2) the cents/kWh charge that the POUs would need to impose in order to recover their stranded costs during the same period the IOUs will recover theirs, 1998-2001.

The obligation to pay an ***IOU*** CTC cannot be avoided by the formation of a POU or by the annexation of any portion of an IOU's territory by a POU. That rule, along with the incentives for POUs to allow direct access for their customers, will substantially reduce the inducement to form new POUs, which was gaining some momentum in the past year.

Public Interest Programs

AB 1890 requires each POU to establish a nonbypassable, "usage based" charge on local distribution service. The funds must be used for "investments by the utility and other parties" in several public interest programs:

- Cost-effective DSM service

- New investment in renewable energy resources and technologies consistent with existing statutes and regulations which promote [renewable energy] resources

- Public interest RD&D that is "not adequately provided by competitive and regulated markets"

- Services for low-income customers.

The charge must be no less than the lowest expenditure by the three large IOUs (PG&E, Edison, and SDG&E) on a percentage of revenue basis. SMUD, for one, is planning to spend even more on public interest programs than AB 1890 requires.

AB 1890's treatment of POU public interest programs differs in two major ways from its treatment of IOU public interest programs. First, while AB 1890 expressly requires the IOU expenditures only for four years, the statute is silent about how long the POU expenditures are to continue. Second, AB 1890 directs the IOUs to spend specific amounts in each of the four specific public interest areas, but it leaves the allocation of POU public interest funds entirely to the discretion of each individual POU. (Like other distinctions between the IOUs and POUs, that difference reflects the close state oversight of the private IOUs versus the deference generally given to the elected POU boards.) We recommend the POUs work closely with the CPUC (which will oversee the IOUs' expenditures on DSM, low income, and some RD&D programs) and the Energy Commission (which will oversee the IOUs' expenditures on renewables and most RD&D programs) to ensure the most effective and thorough, and least redundant, public interest programs.

TABLE 11-1
STRANDED ASSETS FOR MUNICIPAL UTILITIES

	LADWP	IID	SMUD
Stranded Costs $Billion NPV 1997-2007	4.474	0.423	1.346
Average CTC Charge (cents/kWh) 1998-2001	4.16	3.92	3.40

Chapter 12

THE NEED FOR NEW POWER PLANTS

Introduction

The Energy Commission's governing statute requires each ***Electricity Report (ER)*** to contain assessments of the likely levels of electricity demand, and the potential supplies available to meet that demand, during the upcoming 12-year forecast period. [Public Resources Code (PRC) Sections 25305(c), (e), (f); 25309(b).] The Energy Commission must also set forth the criteria it will use in power plant licensing cases during the pendency of each ***ER*** to determine whether proposed power plants are "needed" as defined in the statute.

The task of assessing future electricity supplies has been made substantially more difficult by the onset of industry restructuring. The Energy Commission also faces a challenge in refining its "need criteria" so that they are appropriate in a competitive market.

The Future Demand for Electricity

In order to forecast future electricity demand the Energy Commission staff uses the most sophisticated analytic tools available, developed and refined through years of discussions with the leading experts in the field. An enormous amount of data are analyzed; each one of the major building blocks of demand is assessed, from population and economic growth, to the number and type of electricity-using machines and processes, to electricity prices. The state's major utilities also submit independent forecasts, which are tested, along with the staff's, in public hearings.

As in the past several ***ER*** cycles, there were only minor differences between the staff and utility forecasts for ***ER 96***. For the most part, the Energy Commission adopted the staff forecasts for each of the utility service areas and for the state as a whole. (In the restructured market "utility service areas," in the sense of geographic areas in which utilities are obligated to serve, will not exist; however, until a better categorization is developed, the traditional method will remain.) The adopted forecasts are shown in **Tables 12-1A and 12-1B**. The forecasts are, as required by statute, shown for the fifth and twelfth years of the 12-year forecast period (2000 and 2007); we also include the intermediate year of 2003 for additional detail. They are expressed in terms of megawatts (MW) of peak demand or capacity, which measures the highest demand for electricity at any given time during a year; we also show gigawatt-hours (GWh) of total consumption. The adopted forecasts include savings from "committed" demand-side management (DSM) programs: programs that already exist or that have received funding approval from the appropriate regulatory body.

The price of electricity is the determinant of electricity demand most likely to be affected by restructuring. Other factors, such as population and economic growth, housing starts, and appliance purchases, will not be significantly affected by restructuring. As explained in Chapter 3, however, restructuring will probably not have a major effect on prices, and thus it will probably not have a large effect on future demand.

Balancing Supply and Demand

The Energy Commission divides electricity supplies available or potentially available during the 12-year forecast period into four categories:

- "Existing" supply resources.

- "Committed" supply resources: projects that have already received regulatory approval, including committed DSM.

- "Uncommitted" supply resources: consisting mainly of about 3,000 MW of spot market purchases.

TABLE 12-1A
***ER 96* DEMAND FORECASTS**
(MW)

	2000	2003	2007
PG&E	17976	18675	19570
Small/Med Northern California Municipals	2159	2297	2488
SMUD	2466	2601	2785
SCE	20679	22046	23577
LADWP	5809	5993	6232
Burbank, Glendale, and Pasadena	805	825	854
SDG&E	3884	4221	4651
Department of Water Resources	728	728	728
Other Planning Areas	918	960	1016
Statewide	55424	58346	61901

TABLE 12-1B
***ER 96* DEMAND FORECASTS**
(GWh)

	2000	2003	2007
PG&E	89012	92412	96734
Small/Med Northern California Municipals	9813	10405	11234
SMUD	9242	9801	10671
SCE	96816	103419	110731
LADWP	25668	26730	28063
Burbank, Glendale, and Pasadena	3152	3273	3422
SDG&E	18475	20046	21972
Department of Water Resources	9237	9237	9237
Other Planning Areas	4021	4205	4451
Statewide	265436	279528	296515

- "Uncommitted" DSM: savings from DSM programs that do not yet exist or that have not yet received regulatory funding approval, but that appear to be viable and cost-effective.

The first three categories are relatively straightforward, and, as was the case for the demand forecasts, the other parties in the ***ER 96*** hearings generally agreed with staff's supply assessments. For the fourth category, Energy Commission staff presented three different scenarios:

- "Declining DSM," which assumes no DSM surcharge, and shows private market Uncommitted DSM savings (i.e., nothing beyond the Committed DSM already in the demand forecast).

- "Business as Usual with Spillover Effects," which assumes a DSM surcharge, funding continuing at 1996 levels, and spillover effects of public programs on the private market.

- "Restored Funding with Spillover Effects," which assumes a DSM surcharge and restoration of funding to 1994 levels, beginning in 1999. Spillover effects are at the same level as in the Business as Usual scenario. (Although market transformation effects would be likely to occur in such a scenario, the staff did not include them because savings estimates were not sufficiently developed to be reliable.)

The Business as Usual scenario is closest to the minimum level of DSM funding established in AB 1890 for the 1998 - 2001 period. We therefore used that scenario in the integrated assessment of need.

The Integrated Assessment of Need

The Warren-Alquist Act requires the Energy Commission to include in the ***Electricity Report*** an "integrated assessment of need" (IAN). The statute does not specify precisely what that IAN is or all that it is to contain; rather, it states that the IAN is to be "determined pursuant to" provisions outlining various aspects of the ***ER*** process, including assessments of utility plans for power plant development and alternatives. The statute also requires the IAN to include "the level of statewide and service area electrical energy demand for the forthcoming 5- and 12-year forecasts or assessment period which, in the judgment of the Commission, will reasonably balance the requirements of state and service area growth and development, the protection of the public health and safety, the preservation of environmental quality, the maintenance of a sound economy, and the conservation of resources." [Public Resources Code Section 25309(b).] In order to obtain a license from the Commission, most new power plants must show that they are "[in] conformity" with the IAN. [Public Resources Code Sections 25523(f), 25524(a).]

Clearly the IAN is a flexible concept, one that involves substantial judgment in balancing several important factors and one that must be able to respond to the state's changing energy needs. In the late 1970s when oil use in power plants was the most serious matter for the electricity industry, the IAN focused on that problem and the Energy Commission took steps to reduce the system's dependence on oil. In the early 1980s the IAN emphasized the need to further diversify the state's electricity system; now California has one of the most diverse systems in the world. Since the late 1980s the Commission has focused on increasing the economic efficiency of the electricity system, and the IAN has encouraged the addition of new power plants that, because of their greater efficiencies, will lower total system costs.

Now the state's primary electricity challenge is to develop a fully competitive market among generators and other service providers, without losing the benefits gained from state energy policies in the past twenty years. The ***ER 96*** IAN has been crafted in a way that meets that challenge.

Some argue the Warren-Alquist Act requires the Energy Commission to prescribe the "best" balance of electricity demand and the number and type of power plants and transmission lines to meet the demand. Such a view has never been adopted by the Commission and is now outdated. In a competitive industry, market forces and government's existing environmental, health, and safety regulations should combine to produce a system that is both economically efficient and consistent with public policies.

In recent ***ER***s, the Energy Commission developed the IAN by using complex computer models to assess the economic effects of adding new power plants to California's electricity system. Included in the economic effects were the effects of increased or decreased air emissions resulting from new plants. The IANs analyzed air quality effects only, excluding other environmental impacts of power plants, because they are easiest to quantify and express in economic terms and because they appear to have greater economic detriments than other environmental effects. The IANs showed total system costs would be reduced if power plants with certain characteristics were added to the system.

New fossil-fuel power plants can reduce total system emissions, thereby reducing total system costs, because they are usually cleaner than existing fossil plants and are required to obtain “offsets” from **--** that is, cleanup**--** other pollution sources in order to mitigate their own emissions. The corresponding "need conformance criteria" stated that in power plant licensing cases, proposed projects would be found "needed" **--** that is, found in conformance with the IAN **--** if they would produce economic benefits as least as great as the hypothetical power plants used in the IAN.

The Energy Commission is using a different approach in ***ER 96***, one more appropriate for a competitive market. We are no longer assessing the economic effects of adding new power plants to the system, because such an assessment should be the province of the market. Nor are we assessing, on a global basis in the IAN, the environmental (or health and safety) effects of adding new plants (the environmental and health and safety effects of proposed projects are always assessed in individual licensing proceedings). That is because ***1994 Electricity Report ER*** **(*94*)** showed little effect from changes in air emissions resulting from new power plants, and there is no reason to believe that another assessment, performed soon after ***ER 94*** was adopted, would be significantly different.

Thus, in ***ER 96*** the IAN consists of a basic comparison of the need identified in the demand forecast with likely future supplies. **Table 12-2** shows the statewide assessment for the fifth and twelfth year of the forecast period adopted by the Energy Commission; individual utilities are shown in the Adopted Demand Forecast Appendix. As with the demand forecast, other parties in the proceeding substantially agreed with staff's assessments of supplies and capacity balances. Because of the inherent uncertainties of forecasting **--** which restructuring has magnified **--** the numbers should be viewed as illustrative ranges, not as pinpoint predictions.

In **Table 12-2**, "Capacity Requirements" represents the amount of power plant capacity needed to meet loads with adequate reserves. It is derived from the Demand Forecast shown in **Table 12-1**, with three modifications:

- The Demand Forecast measures demand at the point of consumption. In order to provide the amount of needed power in the places where it is consumed, power plants must actually generate more power, because a small amount of power (a few percent) is lost as it flows over transmission lines.
- In order to ensure service at all times, available power plant capacity must exceed expected demand; some excess is needed to cover unexpected surges in demand and power plant and transmission line outages. The amount of excess, expressed as a percent of total demand, is called the "reserve margin."
- California utilities have some contracts to sell power out-of-state. That amount is not included in the demand forecast, which includes only in-state demand, but it must be accounted for in needed power plant capacity.

Table 12-2 shows apparent capacity deficits in the state beginning soon after the turn of the century. For several reasons, however, the "deficit" should not be interpreted to mean that significant power plant building should begin soon, or that government or other entities need to take immediate action to ensure adequate supplies.

In the first place, supplies substantially exceed demand today, and it will take several years before demand and supply converge. Moreover, the Energy Commission's assessment of future supplies is quite conservative. **Table 12-2**’s “Existing and Committed Resources” category includes no new power plants beyond those already permitted, yet Chapter 4 shows that when supply and demand converge, economic incentives will probably attract new power plant investment. (The Commission has not included such plants in the IAN because the effects that restructuring will have on the electricity system are still uncertain.) In addition, plants that have been retired from active service, but that are still existing and potentially available to return to service if needed ("retired in place"), are also not included in the analysis; nor are out-of-state plants that may be able to sell to California (other than 2,377 MW of short-term capacity). Yet another potential source of new power supplies is additional Uncommitted DSM beyond the amount included in the “Business as Usual” scenario, such as additional savings resulting from successful market transformation programs. **Table 12-3** shows the savings in the “Business as Usual” Uncommitted DSM scenario.

Need Conformance Criteria

In ***ER 94***, the Energy Commission made a significant break with past practice and established need conformance criteria that reflected the free-market view that government should not prevent investors from putting their money where they believe the investments will be competitive. The Commission established two basic need tests:

TABLE 12-2
ER 96 CAPACITY BALANCES
(MW)

Pacific Gas and Electric Service Area	**2000**	**2003**	**2007**
Capacity Requirements	21782	22535	23455
Existing and Committed Resources	19525	19083	18191
Deficit	-2257	-3452	-5264
Uncommitted DSM	1315	1654	2071
Uncommitted Generation Resources	1789	1789	1789
Total Uncommitted Resources	3104	3443	3860
Surplus/Deficit	847	-9	-1404
Southern California Edison Service Area			
Capacity Requirements	22403	23704	25132
Existing and Committed Resources	20693	20714	20546
Deficit	-1710	-2990	-4586
Uncommitted DSM	2669	2846	3426
Uncommitted Generation Resources	588	588	588
Total Uncommitted Resources	3257	3434	4014
Surplus/Deficit	1547	444	-572
San Diego Gas & Electric Service Area			
Capacity Requirements	4436	4807	5281
Existing and Committed Resources	2977	2877	2877
Deficit	-1459	-1930	-2404
Uncommitted DSM	251	358	495
Uncommitted Generation Resources	0	0	0
Total Uncommitted Resources	251	358	495
Surplus/Deficit	-1208	-1572	-1909
Los Angeles Department of Water and Power Service Area			
Capacity Requirements	7072	7227	7510
Existing and Committed Resources	7682	7694	7699
Surplus	610	467	189
Uncommitted DSM	46	69	90
Uncommitted Generation Resources	0	0	0
Total Uncommitted Resources	46	69	90
Surplus	656	536	279
Sacramento Municipal Utility District Service Area			
Capacity Requirements	2814	2956	3151
Existing and Committed Resources	1730	1720	1594
Deficit	-1084	-1236	-1557
Uncommitted DSM	151	202	234
Uncommitted Generation Resources	0	0	0
Total Uncommitted Resources	151	202	234
Surplus/Deficit	-933	-1034	-1323

TABLE 12-2 (continued)
ER 96 CAPACITY BALANCES
(MW)

Imperial Irrigation District	**2000**	**2003**	**2007**
Capacity Requirements	865	934	1029
Existing and Committed Resources	781	636	636
Deficit	-84	-298	-393
Uncommitted DSM	0	0	0
Uncommitted Generation Resources	0	0	0
Total Uncommitted Resources	0	0	0
Surplus/Deficit	-84	-298	-393
California Department of Water Resources			
Capacity Requirements	1552	1552	1552
Existing and Committed Resources	1315	1315	1315
Deficit	-237	-237	-237
Uncommitted DSM	0	0	0
Uncommitted Generation Resources	0	0	0
Total Uncommitted Resources	0	0	0
Surplus/Deficit	-237	-237	-237
Small Public Power Utilities*			
Capacity Requirements	5106	5342	5726
Existing and Committed Resources	4835	4713	4498
Deficit	-271	-629	-1228
Uncommitted DSM	37	42	50
Uncommitted Generation Resources	0	0	0
Total Uncommitted Resources	37	42	50
Surplus/Deficit	-234	-587	-1178
Statewide Totals			
Capacity Requirements	66030	69057	72836
Existing and Committed Resources	59538	58752	57356
Deficit	-6492	-10305	-15480
Uncommitted DSM	4469	5171	6366
Uncommitted Generation Resources	2377	2377	2377
Total Uncommitted Resources	6846	7548	8743
Surplus/Deficit	354	-2757	-6737

*NCPA, Modesto Irrigation District, Turlock Irrigation District, and Cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Redding, Riverside, Santa Clara, and Vernon

TABLE 12-3 ER 96 UNCOMMITTED DSM			
Energy (GWh)	2000	2003	2007
PG&E Service Area	3204	4671	6418
SCE Service Area	2865	4636	6729
SDG&E Service Area	863	1321	1896
LADWP Service Area	272	404	538
SMUD Service Area	480	617	687
IID	0	0	0
DWR	0	0	0
Small Public Power Utilities	16	18	21
Statewide	7700	11667	16289
Peak Demand (MW)			
PG&E Service Area	1315	1654	2071
SCE Service Area	2669	2846	3426
SDG&E Service Area	251	358	495
LADWP Service Area	46	69	90
SMUD Service Area	151	202	234
IID	0	0	0
DWR	0	0	0
Small Public Power Utilities	37	42	50
Statewide	4469	5171	6366

- "Merchant plants" (plants for which investors, not ratepayers, bear the financial risk) were deemed needed, up to half the number of MW established in the statewide IAN.

- "Non-merchant plants" (which were defined as plants owned by utilities or by an affiliate selling to its affiliated utility) were allocated the other half of the MW in the IAN. Proponents of non-merchant plants were required to show economic benefits to ratepayers, using the same criteria previously established in ***ER 90*** and ***ER 92***, in order to be found needed.

Virtually unanimous agreement existed among the parties that ***ER 96*** should continue the essence of ***ER 94***'s hands-off approach for proposed plants that do not put ratepayers at financial risk. Indeed, there was a substantial argument that the Energy Commission should not have "need criteria" even for non-merchant plants. The Commission agrees. Therefore, for the reasons discussed further, the only need criterion we adopt in ***ER 96***, even for non-merchant plants, is to limit the total amount of megawatts permitted on a statewide basis during the pendency of ***ER 96*** to the number of megawatts in **Table 12-2**'s "Statewide Deficit:" 6,737 megawatts in the year 2007.

We have decided to impose a very limited need test for all types of plants for several reasons. First, it is very unlikely that any plant for which ratepayers could be financially responsible will be built. There are four types of such plants: (1) IOU plants that rely on ratepayers for guaranteed cost recovery; (2) plants built by independent power producers (IPPs) with a financial guarantee from IOU ratepayers; (3) municipal utility plants that rely on ratepayers for guaranteed cost recovery; (4) and plants built by IPPs with a financial guarantee from municipal utility ratepayers. It seems unlikely that either type of IOU plant will be proposed during the pendency of ***ER 96***. The two largest IOUs, PG&E and Edison, have declared their intentions not to build. Moreover, any "non-merchant" plant built by an IOU with ratepayer risk would be subject to performance-based ratemaking (PBR), not the traditional cost-of-service regulation that has imposed 100 percent cost recovery on ratepayers; thus PBR would put some of the financial risk of "non-merchant" plants on stockholders and remove it from ratepayers. In that situation it is far from clear that the additional hurdle of a "need test" would be appropriate.

It also seems unlikely that a California IOU would enter into a contract with an IPP that would expose ratepayers to financial risk. The CPUC has already prohibited utility contracts with plants built by their own affiliates (under the ***ER 94*** need test, an affiliate-utility contract was defined as creating a non-merchant plant), and even contracts with non-affiliate plants would be subject to intense CPUC scrutiny.

With regard to POUs, the Energy Commission is reluctant to second-guess the decisions made by elected governmental boards. Whether a municipal utility finances the construction of a plant by owning it or by providing financial guarantees to a private party, the Commission sees little justification for imposing a "need test hurdle" in the current environment in which even municipal utilities are going to have to compete.

In sum, the ***ER 96*** need criterion is this: during the period when ***ER 96*** is applicable, proposed power plants shall be found in conformance with the Integrated Assessment of Need (IAN) as long as the total number of megawatts permitted does not exceed 6,737. [If during the pendency of ***ER 96*** the total number of megawatts permitted exceeds 6,737 (a prospect that is extremely unlikely), the ***ER 96*** Standing Committee shall re-assess the situation and recommend appropriate action for the Commission.]

The role of future ERs in the light of restructuring is unclear; ER 98 may be delayed or eliminated. If there is no ER 98, then interested persons may petition the ER 96 Standing Committee to recommend revisions to the need test.

ER 94 contained need conformance criteria for three additional, specialized categories of power plants: plants subject to need tests created by statute, demonstration projects, and small power plant exemptions. (***ER 94***, pp. 137 - 139.) In ***ER 96***, the Commission continues the ***ER 94*** criteria for those categories, but we recommend that the Legislature re-examine the need for them in 1998 in light of industry restructuring.

The Ongoing Validity of the Integrated Assessment of Need

The shift in focus towards letting market forces define “need” should not be read as a sign that the state is abandoning important public policies. The state’s commitment to maintain the best of its past energy policies can be seen in AB 1890 and in the recommendations in this ***ER***.

In particular, the Energy Commission's substantial relaxation of need conformance criteria in ***ER 94*** and ***ER 96*** should not be interpreted to mean that the Commission believes that the integrated assessment of need should be abandoned. Throughout the Commission's 20-plus-year history, the IAN has allowed state government to respond to electricity challenges in effective and creative ways. In previous ***ER***s, the IAN has focused on:

- Keeping the lights on. The IAN was expressed in simple numerical terms -- (a) How many MW are needed to keep the lights on? (b) How many do we have now? (c) Subtract (b) from (a) and the result is "need."
- Reducing petroleum use. In the middle and late 1970s California power plants used a substantial amount of oil. The IAN created a special category of need for non-petroleum-burning facilities.
- Creating a diverse electricity system. The IAN allocated specified numbers of megawatts to various fuel types.
- Protecting ratepayers' pocketbooks. The IAN assessed whether ratepayers would be better off economically if a new facility were built.
- Encourage construction of new facilities in a competitive market. This, of course, was ***ER 94's*** IAN, and its purpose is carried forward in ***ER 96***.

Each goal was appropriate at the time adopted, and the flexibility of the IAN as established in the Warren-Alquist Act allowed the Energy

Commission to respond to then-current conditions and to change need policies when the conditions changed. The IAN has thus provided a powerful mechanism for carrying out state energy policy. In the context of a developing competitive market and the state's current environmental, reliability, health and safety, and economic circumstances, demonstrating conformance with the IAN should be a simple matter, so that "need conformance" does not stand in the way of investors willing to risk capital. In the longer term, however, conditions may change, and it may be appropriate for state government to make the "need" hurdles higher for power facilities. The IAN provides a useful tool for state regulators to ensure that plants do not threaten important public policies, and therefore it should not be eliminated, even if the need test that it imposes in this ***ER*** (and perhaps future ones) is an easy one to pass.

Moreover, even though the IAN now has little importance as a need assessment tool for regulatory decisions, the analyses supporting the IAN will have substantial importance to investors and other market participants. People who are contemplating risking millions of dollars on new power facilities will want to have the most thorough, reliable, up-to-date, and unbiased information possible, and the Energy Commission's analyses will help meet that need. In addition, the Commission's forecasts will have to spot long-term trends so that policymakers can respond in a timely and cost-effective manner. While restructuring will reduce the state's role in determining the need for power projects, that will not obviate the desirability of having an independent government assessment of the energy trends affecting the seventh-largest economy in the world. Of course, our forecasts should focus on elements and on time frames that are most relevant to the competitive market -- perhaps, for example, emphasizing the near-term rather than a 12-year future, or substituting IOU congestion zones for utility service areas.

Power Plant and Transmission Line Licensing Jurisdiction

In the early 1970s, California's utilities predicted that substantial numbers of large new power plants would have to be constructed in the state. Yet power plant licensing was a lengthy, cumbersome process that required obtaining dozens of local and state permits. One of the reasons for the creation of the Energy Commission in 1974 was to simplify and streamline the licensing process so as to reduce the time and expense involved and to ensure that facilities would be available when needed. The Warren-Alquist Act created a "one-stop" system for thermal power plants of 50 megawatts or more and associated transmission lines, whereby the Commission's certificate takes the place of all other state and local permits.

Despite the existence -- and success -- of the Energy Commission's certification process, energy facility licensing in California remains to some extent fragmented. **Tables 12-4** and **12-5** show the entities with jurisdiction over various types of power plants and transmission lines. The major distinctions in jurisdiction are between larger and smaller projects and among different types of ownership. Those distinctions may no longer be justified.[1]

When the Warren-Alquist Act was enacted, it was believed that power plants less than 50 MW did not need statewide scrutiny because of their relatively smaller economic and environmental impacts. Today, while the impacts are still less in general, it may be unfair to give different regulatory treatment on the basis of an arbitrary size difference, especially in circumstances where small, dispersed generation units are likely to become more prevalent.

With regard to power plant ownership type, there no longer seems to be a valid reason to distinguish between "utility" and "independent" projects, where the goal is that all entities should be subject to competition. The distinction between IOU and POU projects may also be outmoded. POUs have traditionally enjoyed the same kind of preemptive power over inconsistent local laws that is granted to private projects through the Energy Commission, and while there is good reason to defer to the judgment of elected district boards, the demands of competition suggest that all types of projects, whether municipal or otherwise, should face the same regulatory hurdles.

TABLE 12-4 POWER PLANT LICENSING JURISDICTION IN CALIFORNIA			
Project Type	**< 50 MW, Proposed by Publicly Owned Utility**	**< 50 MW, Proposed by Independent Developer or Investor-Owned Utility**	**≥50 MW**
Fossil Fuel (natural gas, oil, coal);Nuclear; Geothermal; Solar Thermal	POU Board	Local Agencies (Plus CPUC if IOU)	CEC
Solar Photovoltaic; Wind	POU Board	Local Agencies (Plus CPUC if IOU)	Same as for projects <50 MW
Hydroelectric	State Water Board; FERC	State Water Board; FERC	State Water Board; FERC; CPUC

TABLE 12-5 TRANSMISSION LINE LICENSING JURISDICTION IN CALIFORNIA			
Project Type	**< 50 kV**	**50 to 200 kV**	**> 200 kV**
Associated with power plant under CEC jurisdiction	CEC	CEC	CEC, plus CPUC if IOU project
Not associated with CEC-jurisdictional power plant, proposed by IOU	Regulated but exempt	CPUC	CPUC
Not associated with CEC-jurisdictional power plant, proposed by POU	POU Board	POU Board	POU Board
Not associated with CEC-jurisdictional power plant; proposed by independent	Local Agencies	Local Agencies	Local Agencies

Moreover, in a competitive market different regulatory treatment for IOU, POU, and independent power plants may create an unlevel regulatory "playing field," giving one type of project an undue advantage. In addition, timely licensing can be critical for the financial viability of projects, and a one-stop permitting process may provide significant cost savings. Finally, a single agency responsible for all permitting can bring a consistently high level of expertise and understanding to projects, and can prevent both the "not-in-my-backyard" syndrome and the phenomenon of local agencies giving inappropriate preferences to development in order to obtain tax advantages.

Transmission line siting jurisdiction is fragmented. The Energy Commission has siting jurisdiction over lines that connect power plants within its jurisdiction to the first point of interconnection with the main grid. The CPUC has jurisdiction over all other IOU transmission lines. POUs have siting jurisdiction over any of their own projects that do not fall within Energy Commission jurisdiction. At this point, it is unclear whether any state authority has siting jurisdiction over a third-party (non-IOU and non-POU) transmission line that is not within Energy Commission jurisdiction. Moreover, it is unclear whether current state authorities would be able to review grid-wide implications of new transmission projects, as opposed to the narrower interests of the particular party sponsoring a project.

Although transmission line planning has been increasingly coordinated at the state and regional level, fragmented transmission licensing jurisdiction has resulted in some conflicts between IOUs and POUs; in addition, there has been intense local opposition to several projects, including POU projects that extended beyond the utility's boundaries. In a competitive market, the increasing importance of transmission access and the shift to congestion pricing may increase the number of proposed transmission projects and create a need for statewide uniformity in licensing. The current fragmented and uncertain transmission line siting jurisdiction could result in needed projects not being built, duplicative projects being built, and inconsistent scope, stringency, and cost of the licensing process.

In light of all the factors discussed, and in order to speed permitting and create a level playing field for all developers, the Energy Commission recommends the Legislature give careful consideration to establishing a single statewide permitting authority for all power plants and transmission lines, regardless of size or ownership.

The Energy Commission's Siting and Regulatory Procedures Committee will examine this matter in more depth in concert with its actions to streamline the Energy Commission's siting process.

We also recommend the Legislature consider another action that would help level the playing field. Currently, IOUs and POUs can exercise the power of eminent domain for their power plant and transmission line projects -- that is, they can force private landowners to sell property at a governmentally-determined fair market value. Independent developers do not have that power. Although eminent domain is not often used, the Legislature should consider creating a system in which eminent domain could be used where necessary for facilities, subject to appropriate state agency oversight. Generation, transmission, and distribution will likely require different treatment.

Endnotes

1. For gas-fired power plants which are the result of competitive solicitations or negotiations, we will continue our process for granting exemptions from NOI requirements to such projects.

Glossary of Abbreviations

Abbreviation	Explanation
AB 1890	Assembly Bill 1890
AFC	Application for Certification (power plant siting and licensing)
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
BGP	Burbank, Glendale, Pasadena
BPA	Bonneville Power Authority
Btu	British Thermal Unit
CADER	California Alliance for Distributed Energy Resources
CADMAC	California DSM Measurement Advisory Committee
CAPCOA	California Air Pollution Control Officers Association
CARB	California Air Resources Board
CARE	California Alternative Rate for Energy
CBEE	California Board for Energy Efficiency
CDWR	California Department of Water Resources
CEQA	California Environmental Quality Act
CFD	Contracts for Differences
CMUA	California Municipal Utilities Association
Commission	California Energy Commission
CO_2	Carbon Dioxide
COTP	California-Oregon Transmission Project
CPUC	California Public Utilities Commission
CTC	Competitive Transition Charge
DER	Distributed Energy Resources
DSM	Demand-Side Management
Edison	Southern California Edison Company
Elfin	Electricity Financial Model (production simulation model)
ER 90	***1990 Electricity Report***
ER 92	***1992 Electricity Report***
ER 94	***1994 Electricity Report***
ER 96	***1996 Electricity Report***
ERC	Emission Reduction Credit
ESPs	Energy Service Providers
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt-hour
IAN	Integrated Assessment of Need
IEEB	Independent Energy Efficiency Board
IID	Imperial Irrigation District
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
IPP	Independent Power Producer
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LAER	Lowest Achievable Emissions Rate
LEV	Low Emission Vehicle
LIRA	Low-Income Rate Assistance

MCP	Market Clearing Price
MID	Modesto Irrigation District
MW	Megawatt
MWD	Metropolitan Water District
MWh	Megawatt-hour
NCPA	Northern California Power Agency
NERC	North American Electricity Reliability Council
NOI	Notice of Intent (power plant siting and licensing)
NO_x	Nitrogen Oxides
NSR	New Source Review
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
O_3	Ozone
PBR	Performance Based Ratemaking
PG&E	Pacific Gas and Electric Company
PM_{10}	Particulate Matter of less than 10 microns
POU	Publicly-Owned Utility
PRC	Public Resources Code
PSD	Prevention of Significant Deterioration
PURPA	Public Utilities Regulatory Policies Act
PX	Power Exchange
QF	Qualifying Facility
RACT	Reasonably Available Control Technology
RD&D	Research, Development, and Demonstration
RECLAIM	Regional Clean Air Incentives Market
ROG	Reactive Organic Gas
RTC	RECLAIM Trading Credit
RTG	Regional Transmission Group
RTP	Real-time Pricing
SC	Scheduling Coordinator
South Coast AQMD	South Coast Air Quality Management District
SCPPA	Southern California Public Power Authority
SCR	Selective Catalytic Reduction
SDG&E	San Diego Gas & Electric
SMES	Superconducting Magnetic Energy Storage
SMUD	Sacramento Municipal Utility District
SO_x	Sulfur Oxide
SO_2	Sulfur Dioxide
SONGS	San Onofre Nuclear Generating Station
SPPE	Small Power Plant Exemption
Staff	Energy Commission Staff
TCC	Transmission Congestion Contract
T&D	Transmission and Distribution
TID	Turlock Irrigation District
TOU	Time-of-Use
TURN	The Utility Reform Network
UDC	Utility Distribution Company
UCAN	Utility Consumers Action Network
WAPA	Western Area Power Administration
WEPEX	Western Power Exchange
WICF	Western Interconnection Coordination Forum
WIEB	Western Interstate Energy Board

WRTA	Western Regional Transmission Association
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
ZEV	Zero Emission Vehicle

GLOSSARY OF RESTRUCTURING DEFINITIONS

Access Charge -- A charge paid by all market participants withdrawing energy from the ISO-controlled grid. The access charge will recover the portion of a transmission-owning utility's transmission revenue requirement not recovered through the transmission congestion fee.

Aggregator -- An entity responsible for planning, scheduling, accounting, billing, and settlement for energy deliveries from the aggregator's portfolio of sellers and buyers. Aggregators seek to bring together customers or generators so they can buy or sell power in bulk, making a profit on the transaction.

Ancillary Services -- The services other than scheduled energy that are required to maintain system reliability and meet WSCC and NERC operating criteria. Such services include spinning, non-spinning, and replacement reserves, voltage control, and black start capability.

Bilateral Contract -- A two-party agreement for the purchase and the sale of energy products and services.

Buyer -- An entity that purchases electrical energy or services from the Power Exchange (PX) or through a bilateral contract on behalf of end-use customers.

Competition Transition Charge (CTC) -- A non-bypassable charge that customers pay to a utility for the recovery of its stranded costs.

Congestion -- A condition that occurs when there is insufficient capacity (rated in megawatts) on a given transmission path to handle or accommodate the scheduled mix of generation to meet demand.

Contract for Difference -- A financial contract for the "purchase" of electricity that enables customers to gain the benefits of an agreed-upon price without having to actively generate or take the power.

Constraints -- Physical and operational limitations on the transfer of electrical power through transmission facilities.

Cost Shifting -- An inappropriate transfer of costs from one group of customers to another or from one utility to another.

Demand -- The rate expressed in kilowatts or megawatts, at which electrical energy is delivered to or by a system, or part of a system, at a given instant in time or averaged over any designated interval of time.

Demand Bid -- A bid into the PX indicating a quantity of energy or ancillary services and, if relevant, a maximum price the customer is prepared to pay. Conversely, the price the customer would take to shut off its demand, a demand bid will only be accepted in the PX auction process if the Market Clearing Price (MCP) set by generators' bids is at or below the price of the demand bid.

Demand Forecast -- An estimate of demand over a designated period of time.

Direct Access -- The ability of buyers and generators to enter into bilateral contracts.

Distribution System -- The distribution assets of a transmission owner or utility distribution company that are not under the control of the ISO and are used to transmit power from the ISO grid interfaces to the end-users.

End-Use Customer -- A residential, commercial, agricultural, or industrial purchaser of electric power that buys electric power to be consumed as a final product and that does not resell the power.

Energy -- The electrical energy produced, flowing or supplied by generation, transmission or distribution facilities, measured in units of watt-hours or standard multiples thereof, e.g., 1000 Wh = 1kWh.

Generation -- Energy delivered from a generating unit.

Generator -- An entity capable of producing energy or ancillary services.

Independent System Operator (ISO) -- The ISO is a state chartered, independent, nonprofit corporation that controls the transmission facilities of all participating transmission owning utilities and dispatches certain generation and loads. Its responsibilities include providing non-discriminatory access to the transmission system under its control, managing congestion, maintaining the reliability and security of the transmission grid, and providing billing and settlement services.

ISO Controlled Grid -- The system of transmission lines and associated facilities of the participating transmission owning utilities that have been placed under the ISO's operational control.

Investor Owned Utility (IOU) -- An electric or gas utility company that is owned by stockholders (who may or may not be customers of the utility).

Load -- An end-use device of an end-use customer that consumes power. Load is not demand, which is a measure of power that a load receives or requires.

Market Clearing Price (MCP) -- The price in a market at which supply equals demand. All demand prepared to pay at least this price has been satisfied and all supply prepared to operate at or below this price has been purchased.

Market Participant -- Any entity, including a scheduling coordinator, that participates in the energy marketplace through the buying, selling, transmission, or distribution of energy or ancillary services into, out of, or through the ISO controlled grid.

Market Power -- The ability of one firm, or a set of firms, to profit from a unilateral price increase.

Market Transformation -- Market transformation programs seek to achieve long lasting changes in the structure or operation of the energy efficiency market by reducing market barriers to the adoption of cost-effective beneficial energy efficiency measures; stimulating sustainable changes in customer demand for energy efficiency; empowering customers with credible information they need to make informed energy efficiency choices; and fostering the development of a well-functioning market for energy efficiency services, to the point where further public intervention is no longer appropriate in that specific market segment.

Performance Based Ratemaking (PBR) -- Regulated rates based in whole or in part on the achievement of specified performance objectives, not incurred costs or a regulated profit.

Power Exchange (PX) -- The PX is a state-chartered, independent, nonprofit corporation charged with conducting an auction for the generators seeking to sell energy for loads that are not otherwise being served by bilateral contracts. The PX will be responsible for scheduling generation in its day-ahead and hour-ahead markets, for determining hourly market clearing prices for its market, and for settlement and billing for suppliers and utility distribution companies (UDCs) using its market.

Public Interest Programs -- Programs historically managed by utilities, and paid for by customers, that provide funds for energy efficiency and conservation; research, development, and demonstration (RD&D); renewable resources; and low-income assistance.

Publicly Owned Utility (POU) -- An electric or gas utility that is owned by its customers.

Seller -- An entity that produces or arranges for the production of electrical energy.

Scheduling Coordinator -- An entity certified by the ISO for the purposes of providing the ISO with balanced hourly schedules of generation to be injected into the transmission grid, and power to be withdrawn from the grid.

Spot Market -- The competitive generation market controlled and coordinated by the PX.

Stranded Costs -- The portion of the costs and obligations that utilities incurred to serve customers under the existing regulatory system that cannot be economically recovered in a deregulated system. Contributing to stranded costs are stranded assets (e.g., generating facilities that produce electricity at above-market costs), the undepreciated portion of a utilities' nuclear power plant capital costs, contract payments to qualifying facilities (QFs), and other items.

Transition Period -- The period of time established to allow IOUs an opportunity to continue to recover costs for generation-related assets and obligations that may not be recoverable in market prices in a competitive generation market. The period is generally defined as January 1, 1998 through December 31, 2001.

Transmission Congestion -- The condition that exists when market participants seek to dispatch generation in a pattern which would result in power flows that cannot be physically accommodated by the transmission system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based upon requested schedules that cannot be accommodated.

Transmission Congestion Contract (TCC) -- A financial instrument that provides a hedge against congestion price differences between the transmission zones into which California has been divided.

Unbundled Rates -- Separate line item charges on a customer's bill for generation, transmission, distribution, and other services and programs.

Unbundled Services -- Separation of generation, transmission, distribution, and other services and programs, which are currently provided to customers in a bundled manner.

Usage Charge -- The amount of money, per kilowatt of scheduled flow, that the ISO charges a scheduling coordinator for use of a specific congested transmission path between different transmission zones.

Utility Distribution Company (UDC) -- An entity that owns a distribution system for the delivery of energy to and from the transmission grid and provides regulated retail service to eligible customers, as well as regulated generation procurement services to those end-use customers who choose not to arrange services through another retailer.

APPENDIX

1996 ELECTRICITY REPORT
CAPACITY RESOURCE ACCOUNTING TABLES
and
ADOPTED DEMAND FORECAST

TABLE 1 STATEWIDE CAPACITY SURPLUS/DEFICIT MW				
Uncommitted DSM Level	2000	2003	2007	2015
Declining DSM	-412	-4756	-10354	-21438
Business as Usual	591	-2520	-6500	-14948
Restored Funding	1132	-1367	-4580	-12102

TABLE 2 STATEWIDE ANNUAL PEAK DEMAND AND ENERGY USE FORECASTS				
	2000	2003	2007	2015
Non-Coincident Peak Demand in MWs (includes losses)	55,422	58,346	61,901	68,032
Annual Energy Requirements in GWh (excludes losses)	265,435	279,528	296,514	324,727

TABLE 3 STATEWIDE ANNUAL SYSTEM CAPACITY REQUIREMENTS (Includes Losses, Exports and Reserve Requirements Assuming Business as Usual DSM)				
	2000	2003	2007	2015
System Capacity Requirements in MWs	64,478	67,505	71,284	78,019

TABLE 4 STATEWIDE ANNUAL EXISTING AND COMMITTED CAPACITY RESOURCES (Excludes Capacity from Long-Term Reserve or Decommissioned Plants) (Assuming Business as Usual DSM)				
	2000	2003	2007	2015
System Capacity Resources in MWs	58,223	57,437	56,041	52,413

TABLE 5 STATEWIDE UNCOMMITTED DEMAND-SIDE MANAGEMENT LEVELS IN Mws (Conservation, Nondispatchable and Dispatchable Load Management Including Loss Savings)				
	2000	2003	2007	2015
Declining DSM	3,598	3,231	3,023	2,661
Business as Usual	4,469	5,171	6,366	8,281
Restored Funding	4,938	6,171	8,031	10,751

TABLE 6
ER 96 CAPACITY RESOURCES w/
DECLINING DSM

Pacific Gas & Electric Service Area, MW				
	2000	2003	2007	2015
Peak Demand	17,976	18,675	19,570	21,205
Exports Requiring Reserves	1,059	1,058	1,015	995
Reserve Requirements	2,797	2,911	3,056	3,335
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	21,832	22,644	23,641	25,535
Utility-Owned Active Resources	14,959	14,505	13,604	13,353
Utility-Owned Reserve/Retired/Decommissioned	1342	1719	2534	2697
PURPA-Qualifying Facility Purchases	2,952	2,952	2,952	2,952
Self-Generation	967	979	988	1,000
Bulk Utility Purchases	647	647	647	647
Total Existing & Committed Resources	19,525	19,083	18,191	17,952
Surplus/Deficit	-2,307	-3,561	-5,450	-7,583
Nondispatchable Efficiency & Load Mgmt	371	335	251	70
Dispatchable Load Management	617	617	617	617
Assumed Spot Capacity, Seasonal Exchange	1,789	1,789	1,789	1,789
Total Uncommitted	2,777	2,741	2,657	2,476
Surplus/Deficit w/ Uncommitted	470	-820	-2,793	-5,107
(Efficiency & Load Mgmt as % of Deficit)	42.8%	26.7%	15.9%	9.1%
San Diego Gas & Electric Service Area, MW				
	2000	2003	2007	2015
Peak Demand	3,884	4,221	4,651	5,357
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	565	617	685	801
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	4,449	4,838	5,336	6,158
Utility-Owned Active Resources	2,403	2,403	2,403	1,973
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	430
PURPA-Qualifying Facility Purchases	348	348	348	348
Self-Generation	59	59	59	59
Bulk Utility Purchases	167	67	67	67
Total Existing & Committed Resources	2,977	2,877	2,877	2,447
Surplus/Deficit	-1,472	-1,961	-2,459	-3,711
Nondispatchable Efficiency & Load Mgmt	115	109	82	19
Dispatchable Load Management	44	44	44	44
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	159	153	126	63
Surplus/Deficit w/ Uncommitted	-1,313	-1,808	-2,333	-3,648
(Efficiency & Load Mgmt as % of Deficit)	10.8%	7.8%	5.1%	1.7%

TABLE 6
ER 96 CAPACITY RESOURCES w/
DECLINING DSM

Southern California Edison and Public Power Utilities Integrated Planning Area, MW				
	2000	2003	2007	2015
Peak Demand	20,679	22,046	23,577	26,000
Exports Requiring Reserves	210	110	0	0
Reserve Requirements	3,175	3,380	3,612	4,016
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	24,064	25,536	27,189	30,016
Utility-Owned Active Resources	14,923	14,923	14,923	13,203
Utility-Owned Reserve/Retired/Decommissioned	1081	1081	1081	2800
PURPA-Qualifying Facility Purchases	3,694	3,695	3,695	3,695
Self-Generation	596	616	639	645
Bulk Utility Purchases	2,503	2,463	2,171	1,314
Total Existing & Committed Resources	21,716	21,697	21,428	18,857
Surplus/Deficit	-2,348	-3,839	-5,761	-11,159
Nondispatchable Efficiency & Load Mgmt	449	412	360	253
Dispatchable Load Management	1,902	1,640	1,641	1,641
Assumed PPU "Self-Resourcing"	528	649	850	1,315
Assumed Spot Capacity, Seasonal Exchange	588	588	588	588
Total Uncommitted	3,467	3,289	3,439	3,797
Surplus/Deficit w/ Uncommitted	1,119	-550	-2,322	-7,362
(Efficiency & Load Mgmt as % of Deficit)	100.1%	53.5%	34.7%	17.0%
Southern California Edison Company Service Area, MW				
	2000	2003	2007	2015
Peak Demand	19,292	20,577	22,001	24,185
Exports Requiring Reserves	210	110	0	0
Reserve Requirements	2,960	3,154	3,372	3,741
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	22,462	23,841	25,373	27,926
Utility-Owned Active Resources	14,277	14,277	14,277	12,663
Utility-Owned Reserve/Retired/Decommissioned	1081	1081	1081	2694
PURPA-Qualifying Facility Purchases	3,694	3,695	3,695	3,695
Self-Generation	596	616	639	645
Bulk Utility Purchases	2,126	2,126	1,935	1,183
Total Existing & Committed Resources	20,693	20,714	20,546	18,186
Surplus/Deficit	-1,769	-3,127	-4,827	-9,740
Nondispatchable Efficiency & Load Mgmt	407	358	286	159
Dispatchable Load Management	1,893	1,630	1,630	1,630
Assumed Spot Capacity, Seasonal Exchange	588	588	588	588
Total Uncommitted	2,888	2,576	2,504	2,377
Surplus/Deficit w/ Uncommitted	1,119	-551	-2,323	-7,363
(Efficiency & Load Mgmt as % of Deficit)	130.0%	63.6%	39.7%	18.4%

TABLE 6

ER 96 CAPACITY RESOURCES w/ DECLINING DSM

Los Angeles Department of Water and Power Service Area, MW	2000	2003	2007	2015
Peak Demand	5,809	5,993	6,232	6,639
Exports Requiring Reserves	92	41	41	41
Reserve Requirements	1,176	1,204	1,254	1,336
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	7,077	7,238	7,527	8,016
Utility-Owned Active Resources	6,743	6,743	6,743	6,743
Utility-Owned Reserve/Retired/Decommissioned	373	373	373	373
PURPA-Qualifying Facility Purchases	1	1	1	1
Self-Generation	242	254	259	263
Bulk Utility Purchases	696	696	696	591
Total Existing & Committed Resources	7,682	7,694	7,699	7,598
Surplus/Deficit	605	456	172	-418
Nondispatchable Efficiency & Load Mgmt	21	13	5	0
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	21	13	5	0
Surplus/Deficit w/ Uncommitted	626	469	177	-418
(Efficiency & Load Mgmt as % of Deficit)	-3.5%	-2.9%	-2.9%	0.0%

Sacramento Municipal Utility District Service Area, MW	2000	2003	2007	2015
Peak Demand	2,466	2,601	2,785	3,183
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	353	363	378	407
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	2,819	2,964	3,163	3,590
Utility-Owned Active Resources	1,133	1,123	1,097	1,093
Utility-Owned Reserve/Retired/Decommissioned	900	900	900	900
PURPA-Qualifying Facility Purchases	0	0	0	0
Self-Generation	0	0	0	0
Bulk Utility Purchases	597	597	497	457
Total Existing & Committed Resources	1,730	1,720	1,594	1,550
Surplus/Deficit	-1,089	-1,244	-1,569	-2,040
Nondispatchable Efficiency & Load Mgmt	68	51	22	2
Dispatchable Load Management	25	32	36	45
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	93	83	58	47
Surplus/Deficit w/ Uncommitted	-996	-1,161	-1,511	-1,993
(Efficiency & Load Mgmt as % of Deficit)	8.5%	6.7%	3.7%	2.3%

TABLE 6
ER 96 CAPACITY RESOURCES w/
DECLINING DSM

Imperial Irrigation District, MW

	2000	2003	2007	2015
Peak Demand	750	812	895	1,058
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	115	122	134	159
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	865	934	1,029	1,217
Utility-Owned Active Resources	602	603	603	603
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	0
PURPA-Qualifying Facility Purchases	0	0	0	0
Self-Generation	0	0	0	0
Bulk Utility Purchases	179	33	33	33
Total Existing & Committed Resources	781	636	636	636
Surplus/Deficit	-84	-298	-393	-581
Nondispatchable Efficiency & Load Mgmt	0	0	0	0
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	0	0	0	0
Surplus/Deficit w/ Uncommitted	-84	-298	-393	-581
(Efficiency & Load Mgmt as % of Deficit)	0.0%	0.0%	0.0%	0.0%

California Department of Water Resources, MW

	2000	2003	2007	2015
Peak Demand	728	728	728	728
Exports Requiring Reserves	624	624	624	624
Reserve Requirements	200	200	200	200
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	1,552	1,552	1,552	1,552
Utility-Owned Active Resources	1,148	1,148	1,148	1,148
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	0
PURPA-Qualifying Facility Purchases	1	1	1	1
Self-Generation	0	0	0	0
Bulk Utility Purchases	166	166	166	100
Total Existing & Committed Resources	1,315	1,315	1,315	1,249
Surplus/Deficit	-237	-237	-237	-303
Nondispatchable Efficiency & Load Mgmt	0	0	0	0
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	0	0	0	0
Surplus/Deficit w/ Uncommitted	-237	-237	-237	-303
(Efficiency & Load Mgmt as % of Deficit)	0.0%	0.0%	0.0%	0.0%

TABLE 6
ER 96 CAPACITY RESOURCES w/
DECLINING DSM

Total Three Investor-Owned Utilities, (MW) PG&E, Edison and SDG&E

	2000	2003	2007	2015
Peak Demand	41,152	43,473	46,222	50,747
Exports Requiring Reserves	1,269	1,168	1,015	995
Reserve Requirements	6,322	6,682	7,113	7,877
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	48,743	51,323	54,350	59,619
Utility-Owned Active Resources	31,639	31,185	30,284	27,989
Utility-Owned Reserve/Retired/Decommissioned	2,423	2,800	3,615	5,821
PURPA-Qualifying Facility Purchases	6,994	6,995	6,995	6,995
Self-Generation	1,622	1,654	1,686	1,704
Bulk Utility Purchases	2,940	2,840	2,649	1,897
Total Existing & Committed Resources	43,195	42,674	41,614	38,585
Surplus/Deficit	-5,548	-8,649	-12,736	-21,034
Nondispatchable Efficiency & Load Mgmt	893	802	619	248
Dispatchable Load Management	2,554	2,291	2,291	2,291
Assumed Spot Capacity, Seasonal Exchange	2,377	2,377	2,377	2,377
Total Uncommitted	5,824	5,470	5,287	4,916
Surplus/Deficit w/ Uncommitted	276	-3,179	-7,449	-16,118
(Efficiency & Load Mgmt as % of Deficit)	62.1%	35.8%	22.8%	12.1%

Total Six Large Utilities, (MW) PG&E, SDG&E, Edison, LADWP, SMUD, IID

	2000	2003	2007	2015
Peak Demand	50,177	52,879	56,134	61,627
Exports Requiring Reserves	1,361	1,209	1,056	1,036
Reserve Requirements	7,966	8,371	8,879	9,779
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	59,504	62,459	66,069	72,442
Utility-Owned Active Resources	40,117	39,654	38,727	36,428
Utility-Owned Reserve/Retired/Decommissioned	3,696	4,073	4,888	7,094
PURPA-Qualifying Facility Purchases	6,995	6,996	6,996	6,996
Self-Generation	1,864	1,908	1,945	1,967
Bulk Utility Purchases	4,412	4,166	3,875	2,978
Total Existing & Committed Resources	53,388	52,724	51,543	48,369
Surplus/Deficit	-6,116	-9,735	-14,526	-24,073
Nondispatchable Efficiency & Load Mgmt	982	866	646	250
Dispatchable Load Management	2,579	2,323	2,327	2,336
Assumed Spot Capacity, Seasonal Exchange	2,377	2,377	2,377	2,377
Total Uncommitted	5,938	5,566	5,350	4,963
Surplus/Deficit w/ Uncommitted	-178	-4,169	-9,176	-19,110
(Efficiency & Load Mgmt as % of Deficit)	58.2%	32.8%	20.5%	10.7%

TABLE 6
ER 96 CAPACITY RESOURCES w/
DECLINING DSM

Total Three Investor-Owned Utilities, (MW) PG&E, Edison and SDG&E

	2000	2003	2007	2015
Peak Demand	41,152	43,473	46,222	50,747
Exports Requiring Reserves	1,269	1,168	1,015	995
Reserve Requirements	6,322	6,682	7,113	7,877
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	48,743	51,323	54,350	59,619
Utility-Owned Active Resources	31,639	31,185	30,284	27,989
Utility-Owned Reserve/Retired/Decommissioned	2,423	2,800	3,615	5,821
PURPA-Qualifying Facility Purchases	6,994	6,995	6,995	6,995
Self-Generation	1,622	1,654	1,686	1,704
Bulk Utility Purchases	2,940	2,840	2,649	1,897
Total Existing & Committed Resources	43,195	42,674	41,614	38,585
Surplus/Deficit	-5,548	-8,649	-12,736	-21,034
Nondispatchable Efficiency & Load Mgmt	893	802	619	248
Dispatchable Load Management	2,554	2,291	2,291	2,291
Assumed Spot Capacity, Seasonal Exchange	2,377	2,377	2,377	2,377
Total Uncommitted	5,824	5,470	5,287	4,916
Surplus/Deficit w/ Uncommitted	276	-3,179	-7,449	-16,118
(Efficiency & Load Mgmt as % of Deficit)	62.1%	35.8%	22.8%	12.1%

Total Six Large Utilities, (MW) PG&E, SDG&E, Edison, LADWP, SMUD, IID

	2000	2003	2007	2015
Peak Demand	50,177	52,879	56,134	61,627
Exports Requiring Reserves	1,361	1,209	1,056	1,036
Reserve Requirements	7,966	8,371	8,879	9,779
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	59,504	62,459	66,069	72,442
Utility-Owned Active Resources	40,117	39,654	38,727	36,428
Utility-Owned Reserve/Retired/Decommissioned	3,696	4,073	4,888	7,094
PURPA-Qualifying Facility Purchases	6,995	6,996	6,996	6,996
Self-Generation	1,864	1,908	1,945	1,967
Bulk Utility Purchases	4,412	4,166	3,875	2,978
Total Existing & Committed Resources	53,388	52,724	51,543	48,369
Surplus/Deficit	-6,116	-9,735	-14,526	-24,073
Nondispatchable Efficiency & Load Mgmt	982	866	646	250
Dispatchable Load Management	2,579	2,323	2,327	2,336
Assumed Spot Capacity, Seasonal Exchange	2,377	2,377	2,377	2,377
Total Uncommitted	5,938	5,566	5,350	4,963
Surplus/Deficit w/ Uncommitted	-178	-4,169	-9,176	-19,110
(Efficiency & Load Mgmt as % of Deficit)	58.2%	32.8%	20.5%	10.7%

TABLE 6
ER 96 CAPACITY RESOURCES w/
DECLINING DSM

Detail of Small Public Power Utilities, MW

	2000	2003	2007	2015
Total Capacity Requirements	**5,106**	**5,342**	**5,726**	**6,447**
NCPA	685	717	767	872
City of Redding	260	283	319	401
City of Santa Clara	444	462	488	530
Modesto Irrigation District	638	694	767	863
Turlock Irrigation District	417	435	466	536
City of Burbank	320	328	338	357
City of Glendale	371	382	396	418
City of Pasadena	301	280	292	312
Southern California Public Power				
Anaheim	670	711	772	927
Azusa	60	63	64	66
Banning	39	41	45	50
Colton	100	106	114	130
Riverside	591	630	688	775
Vernon	210	210	210	210
Existing & Committed Resources (incl, Imports)	**4,835**	**4,713**	**4,498**	**4,044**
NCPA	770	755	741	728
City of Redding	298	298	298	298
City of Santa Clara	557	514	470	460
Modesto Irrigation District	486	474	466	442
Turlock Irrigation District	405	397	391	314
City of Burbank	389	389	389	339
City of Glendale	391	391	391	391
City of Pasadena	361	361	361	350
Southern California Public Power				
Anaheim	480	480	440	348
Azusa	64	48	33	33
Banning	43	38	35	35
Colton	61	38	38	35
Riverside	426	426	401	227
Vernon	104	104	44	44
Energy Efficiency	**36.7**	**41.8**	**50.1**	**75**
NCPA	6	8	9	17
City of Redding	2	2	2	3
City of Santa Clara	1	2	3	4
Modesto Irrigation District	9	5	2	1
Turlock Irrigation District	0	0	0	0
City of Burbank	0	0	0	0
City of Glendale	0	0	0	0
City of Pasadena	0	0	0	0
Southern California Public Power				
Anaheim	19	25	34	50
Azusa	0	0	0	0
Banning	0	0	0	0
Colton	0	0	0	0
Riverside	0	0	0	0
Vernon	0	0	0	0

TABLE 6

ER 96 CAPACITY RESOURCES w/ DECLINING DSM

Detail of Small Public Power Utilities, MW	2000	2003	2007	2015
Surplus/Deficit	**-234**	**-587**	**-1,178**	**-2,328**
NCPA	91	46	-17	-127
City of Redding	40	17	-19	-100
City of Santa Clara	114	54	-15	-66
Modesto Irrigation District	-143	-215	-299	-420
Turlock Irrigation District	-12	-38	-75	-222
City of Burbank	69	61	51	-18
City of Glendale	20	9	-5	-27
City of Pasadena	60	81	69	38
Southern California Public Power				
Anaheim	-171	-206	-298	-529
Azusa	4	-15	-31	-33
Banning	4	-3	-10	-15
Colton	-39	-68	-76	-95
Riverside	-165	-204	-287	-548
Vernon	-106	-106	-166	-166

Statewide Capacity Requirements, MW	2000	2003	2007	2015
Capacity Requirements	64,610	67,801	71,795	78,889
Existing & Committed Resources	58,223	57,437	56,041	52,413
Surplus/Deficit	-6,387	-10,364	-15,754	-26,476
Energy Efficiency	3,598	3,231	3,023	2,661
Other Uncommitted Resources	2,377	2,377	2,377	2,377
Total Uncommitted Resources	5,975	5,608	5,400	5,038
Surplus/Deficit w/Uncommitted	-412	-4,756	-10,354	-21,438

Statewide Total Excludes CDWR

TABLE 7
ER 96 CAPACITY RESOURCES w/
BUSINESS AS USUAL DSM

Pacific Gas & Electric Service Area, MW

	2000	2003	2007	2015
Peak Demand	17,976	18,675	19,570	21,205
Exports Requiring Reserves	1,059	1,058	1,015	995
Reserve Requirements	2,747	2,802	2,870	3,034
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	21,782	22,535	23,455	25,234
Utility-Owned Active Resources	14,959	14,505	13,604	13,353
Utility-Owned Reserve/Retired/Decommissioned	1342	1719	2534	2697
PURPA-Qualifying Facility Purchases	2,952	2,952	2,952	2,952
Self-Generation	967	979	988	1,000
Bulk Utility Purchases	647	647	647	647
Total Existing & Committed Resources	19,525	19,083	18,191	17,952
Surplus/Deficit	-2,257	-3,452	-5,264	-7,282
Nondispatchable Efficiency & Load Mgmt	698	1,037	1,454	2,011
Dispatchable Load Management	617	617	617	617
Assumed Spot Capacity, Seasonal Exchange	1,789	1,789	1,789	1,789
Total Uncommitted	3,104	3,443	3,860	4,417
Surplus/Deficit w/ Uncommitted	847	-9	-1,404	-2,865
(Efficiency & Load Mgmt as % of Deficit)	58.3%	47.9%	39.3%	36.1%

San Diego Gas & Electric Service Area, MW

	2000	2003	2007	2015
Peak Demand	3,884	4,221	4,651	5,357
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	552	586	630	706
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	4,436	4,807	5,281	6,063
Utility-Owned Active Resources	2,403	2,403	2,403	1,973
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	430
PURPA-Qualifying Facility Purchases	348	348	348	348
Self-Generation	59	59	59	59
Bulk Utility Purchases	167	67	67	67
Total Existing & Committed Resources	2,977	2,877	2,877	2,447
Surplus/Deficit	-1,459	-1,930	-2,404	-3,616
Nondispatchable Efficiency & Load Mgmt	207	314	451	651
Dispatchable Load Management	44	44	44	44
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	251	358	495	695
Surplus/Deficit w/ Uncommitted	-1,208	-1,572	-1,909	-2,921
(Efficiency & Load Mgmt as % of Deficit)	17.2%	18.5%	20.6%	19.2%

TABLE 7
ER 96 CAPACITY RESOURCES w/
BUSINESS AS USUAL DSM

Southern California Edison and Public Power Utilities Integrated Planning Area, MW

	2000	2003	2007	2015
Peak Demand	20,679	22,046	23,577	26,000
Exports Requiring Reserves	210	110	0	0
Reserve Requirements	3,116	3,243	3,371	3,580
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	24,005	25,399	26,948	29,580
Utility-Owned Active Resources	14,923	14,923	14,923	13,203
Utility-Owned Reserve/Retired/Decommissioned	1081	1081	1081	2800
PURPA-Qualifying Facility Purchases	3,694	3,695	3,695	3,695
Self-Generation	596	616	639	645
Bulk Utility Purchases	2,503	2,463	2,171	1,314
Total Existing & Committed Resources	21,716	21,697	21,428	18,857
Surplus/Deficit	-2,289	-3,702	-5,520	-10,723
Nondispatchable Efficiency & Load Mgmt	818	1,269	1,870	2,978
Dispatchable Load Management	1,902	1,640	1,641	1,641
Assumed PPU "Self-Resourcing"	528	649	850	1,315
Assumed Spot Capacity, Seasonal Exchange	588	588	588	588
Total Uncommitted	3,836	4,146	4,949	6,522
Surplus/Deficit w/ Uncommitted	1,547	444	-571	-4,201
(Efficiency & Load Mgmt as % of Deficit)	118.8%	78.6%	63.6%	43.1%

Southern California Edison Company Service Area, MW

	2000	2003	2007	2015
Peak Demand	19,292	20,577	22,001	24,185
Exports Requiring Reserves	210	110	0	0
Reserve Requirements	2,901	3,017	3,131	3,305
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	22,403	23,704	25,132	27,490
Utility-Owned Active Resources	14,277	14,277	14,277	12,663
Utility-Owned Reserve/Retired/Decommissioned	1081	1081	1081	2694
PURPA-Qualifying Facility Purchases	3,694	3,695	3,695	3,695
Self-Generation	596	616	639	645
Bulk Utility Purchases	2,126	2,126	1,935	1,183
Total Existing & Committed Resources	20,693	20,714	20,546	18,186
Surplus/Deficit	-1,710	-2,990	-4,586	-9,304
Nondispatchable Efficiency & Load Mgmt	776	1,216	1,796	2,885
Dispatchable Load Management	1,893	1,630	1,630	1,630
Assumed Spot Capacity, Seasonal Exchange	588	588	588	588
Total Uncommitted	3,257	3,434	4,014	5,103
Surplus/Deficit w/ Uncommitted	1,547	444	-572	-4,201
(Efficiency & Load Mgmt as % of Deficit)	156.1%	95.2%	74.7%	48.5%

TABLE 7

**ER 96 CAPACITY RESOURCES w/
BUSINESS AS USUAL DSM**

Los Angeles Department of Water and Power Service Area, MW				
	2000	2003	2007	2015
Peak Demand	5,809	5,993	6,232	6,639
Exports Requiring Reserves	92	41	41	41
Reserve Requirements	1,171	1,193	1,237	1,312
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	7,072	7,227	7,510	7,992
Utility-Owned Active Resources	6,743	6,743	6,743	6,743
Utility-Owned Reserve/Retired/Decommissioned	373	373	373	373
PURPA-Qualifying Facility Purchases	1	1	1	1
Self-Generation	242	254	259	263
Bulk Utility Purchases	696	696	696	591
Total Existing & Committed Resources	7,682	7,694	7,699	7,598
Surplus/Deficit	610	467	189	-394
Nondispatchable Efficiency & Load Mgmt	46	69	90	121
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	46	69	90	121
Surplus/Deficit w/ Uncommitted	656	536	279	-273
(Efficiency & Load Mgmt as % of Deficit)	-7.5%	-14.8%	-47.6%	30.7%

Sacramento Municipal Utility District Service Area, MW				
	2000	2003	2007	2015
Peak Demand	2,466	2,601	2,785	3,183
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	348	355	366	393
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	2,814	2,956	3,151	3,576
Utility-Owned Active Resources	1,133	1,123	1,097	1,093
Utility-Owned Reserve/Retired/Decommissioned	900	900	900	900
PURPA-Qualifying Facility Purchases	0	0	0	0
Self-Generation	0	0	0	0
Bulk Utility Purchases	597	597	497	457
Total Existing & Committed Resources	1,730	1,720	1,594	1,550
Surplus/Deficit	-1,084	-1,236	-1,557	-2,026
Nondispatchable Efficiency & Load Mgmt	126	170	198	202
Dispatchable Load Management	25	32	36	45
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	151	202	234	247
Surplus/Deficit w/ Uncommitted	-933	-1,034	-1,323	-1,779
(Efficiency & Load Mgmt as % of Deficit)	13.9%	16.3%	15.0%	12.2%

TABLE 7
ER 96 CAPACITY RESOURCES w/
BUSINESS AS USUAL DSM

Imperial Irrigation District, MW

	2000	2003	2007	2015
Peak Demand	750	812	895	1,058
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	115	122	134	159
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	865	934	1,029	1,217
Utility-Owned Active Resources	602	603	603	603
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	0
PURPA-Qualifying Facility Purchases	0	0	0	0
Self-Generation	0	0	0	0
Bulk Utility Purchases	179	33	33	33
Total Existing & Committed Resources	781	636	636	636
Surplus/Deficit	-84	-298	-393	-581
Nondispatchable Efficiency & Load Mgmt	0	0	0	0
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	0	0	0	0
Surplus/Deficit w/ Uncommitted	-84	-298	-393	-581
(Efficiency & Load Mgmt as % of Deficit)	0.0%	0.0%	0.0%	0.0%

California Department of Water Resources, MW

	2000	2003	2007	2015
Peak Demand	728	728	728	728
Exports Requiring Reserves	624	624	624	624
Reserve Requirements	200	200	200	200
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	1,552	1,552	1,552	1,552
Utility-Owned Active Resources	1,148	1,148	1,148	1,148
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	0
PURPA-Qualifying Facility Purchases	1	1	1	1
Self-Generation	0	0	0	0
Bulk Utility Purchases	166	166	166	100
Total Existing & Committed Resources	1,315	1,315	1,315	1,249
Surplus/Deficit	-237	-237	-237	-303
Nondispatchable Efficiency & Load Mgmt	0	0	0	0
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	0	0	0	0
Surplus/Deficit w/ Uncommitted	-237	-237	-237	-303
(Efficiency & Load Mgmt as % of Deficit)	0.0%	0.0%	0.0%	0.0%

TABLE 7
ER 96 CAPACITY RESOURCES w/
BUSINESS AS USUAL DSM

Total Three Investor-Owned Utilities, (MW) PG&E, Edison. SDG&E	2000	2003	2007	2015
Peak Demand	41,152	43,473	46,222	50,747
Exports Requiring Reserves	1,269	1,168	1,015	995
Reserve Requirements	6,200	6,405	6,631	7,045
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	48,621	51,046	53,868	58,787
Utility-Owned Active Resources	31,639	31,185	30,284	27,989
Utility-Owned Reserve/Retired/Decommissioned	2,423	2,800	3,615	5,821
PURPA-Qualifying Facility Purchases	6,994	6,995	6,995	6,995
Self-Generation	1,622	1,654	1,686	1,704
Bulk Utility Purchases	2,940	2,840	2,649	1,897
Total Existing & Committed Resources	43,195	42,674	41,614	38,585
Surplus/Deficit	-5,426	-8,372	-12,254	-20,202
Nondispatchable Efficiency & Load Mgmt	1,681	2,567	3,701	5,547
Dispatchable Load Management	2,554	2,291	2,291	2,291
Assumed Spot Capacity, Seasonal Exchange	2,377	2,377	2,377	2,377
Total Uncommitted	6,612	7,235	8,369	10,215
Surplus/Deficit w/ Uncommitted	1,186	-1,137	-3,885	-9,987
(Efficiency & Load Mgmt as % of Deficit)	78.1%	58.0%	48.9%	38.8%

Total Six Large Utilities, (MW) PG&E, SDG&E, Edison, LADWP, SMUD, IID	2000	2003	2007	2015
Peak Demand	50,177	52,879	56,134	61,627
Exports Requiring Reserves	1,361	1,209	1,056	1,036
Reserve Requirements	7,834	8,075	8,368	8,909
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	59,372	62,163	65,558	71,572
Utility-Owned Active Resources	40,117	39,654	38,727	36,428
Utility-Owned Reserve/Retired/Decommissioned	3,696	4,073	4,888	7,094
PURPA-Qualifying Facility Purchases	6,995	6,996	6,996	6,996
Self-Generation	1,864	1,908	1,945	1,967
Bulk Utility Purchases	4,412	4,166	3,875	2,978
Total Existing & Committed Resources	53,388	52,724	51,543	48,369
Surplus/Deficit	-5,984	-9,439	-14,015	-23,203
Nondispatchable Efficiency & Load Mgmt	1,853	2,806	3,989	5,870
Dispatchable Load Management	2,579	2,323	2,327	2,336
Assumed Spot Capacity, Seasonal Exchange	2,377	2,377	2,377	2,377
Total Uncommitted	6,809	7,506	8,693	10,583
Surplus/Deficit w/ Uncommitted	825	-1,933	-5,322	-12,620
(Efficiency & Load Mgmt as % of Deficit)	74.1%	54.3%	45.1%	35.4%

TABLE 7
ER 96 CAPACITY RESOURCES w/
BUSINESS AS USUAL DSM

Detail of Small Public Power Utilities, MW

	2000	2003	2007	2015
Total Capacity Requirements	**5,106**	**5,342**	**5,726**	**6,447**
NCPA	685	717	767	872
City of Redding	260	283	319	401
City of Santa Clara	444	462	488	530
Modesto Irrigation District	638	694	767	863
Turlock Irrigation District	417	435	466	536
City of Burbank	320	328	338	357
City of Glendale	371	382	396	418
City of Pasadena	301	280	292	312
Southern California Public Power				
Anaheim	670	711	772	927
Azusa	60	63	64	66
Banning	39	41	45	50
Colton	100	106	114	130
Riverside	591	630	688	775
Vernon	210	210	210	210
Existing & Committed Resources (incl, Imports)	**4,835**	**4,713**	**4,498**	**4,044**
NCPA	770	755	741	728
City of Redding	298	298	298	298
City of Santa Clara	557	514	470	460
Modesto Irrigation District	486	474	466	442
Turlock Irrigation District	405	397	391	314
City of Burbank	389	389	389	339
City of Glendale	391	391	391	391
City of Pasadena	361	361	361	350
Southern California Public Power				
Anaheim	480	480	440	348
Azusa	64	48	33	33
Banning	43	38	35	35
Colton	61	38	38	35
Riverside	426	426	401	227
Vernon	104	104	44	44
Energy Efficiency	**36.7**	**41.8**	**50.1**	**75**
NCPA	6	8	9	17
City of Redding	2	2	2	3
City of Santa Clara	1	2	3	4
Modesto Irrigation District	9	5	2	1
Turlock Irrigation District	0	0	0	0
City of Burbank	0	0	0	0
City of Glendale	0	0	0	0
City of Pasadena	0	0	0	0
Southern California Public Power				
Anaheim	19	25	34	50
Azusa	0	0	0	0
Banning	0	0	0	0
Colton	0	0	0	0
Riverside	0	0	0	0
Vernon	0	0	0	0

TABLE 7

ER 96 CAPACITY RESOURCES w/ BUSINESS AS USUAL DSM

Detail of Small Public Power Utilities, MW				
	2000	2003	2007	2015
Surplus/Deficit	**-234**	**-587**	**-1,178**	**-2,328**
NCPA	91	46	-17	-127
City of Redding	40	17	-19	-100
City of Santa Clara	114	54	-15	-66
Modesto Irrigation District	-143	-215	-299	-420
Turlock Irrigation District	-12	-38	-75	-222
City of Burbank	69	61	51	-18
City of Glendale	20	9	-5	-27
City of Pasadena	60	81	69	38
Southern California Public Power				
Anaheim	-171	-206	-298	-529
Azusa	4	-15	-31	-33
Banning	4	-3	-10	-15
Colton	-39	-68	-76	-95
Riverside	-165	-204	-287	-548
Vernon	-106	-106	-166	-166

Statewide Capacity Requirements, MW				
	2000	2003	2007	2015
Capacity Requirements	64,478	67,505	71,284	78,019
Existing & Committed Resources	58,223	57,437	56,041	52,413
Surplus/Deficit	-6,255	-10,068	-15,243	-25,606
Energy Efficiency	4,469	5,171	6,366	8,281
Other Uncommitted Resources	2,377	2,377	2,377	2,377
Total Uncommitted Resources	6,846	7,548	8,743	10,658
Surplus/Deficit w/Uncommitted	591	-2,520	-6,500	-14,948

Statewide Total Excludes CDWR

TABLE 8
ER 96 CAPACITY RESOURCES w/
RESTORED FUNDING DSM

Pacific Gas & Electric Service Area, MW				
	2000	2003	2007	2015
Peak Demand	17,976	18,675	19,570	21,205
Exports Requiring Reserves	1,059	1,058	1,015	995
Reserve Requirements	2,722	2,752	2,784	2,913
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	21,757	22,485	23,369	25,113
Utility-Owned Active Resources	14,959	14,505	13,604	13,353
Utility-Owned Reserve/Retired/Decommissioned	1342	1719	2534	2697
PURPA-Qualifying Facility Purchases	2,952	2,952	2,952	2,952
Self-Generation	967	979	988	1,000
Bulk Utility Purchases	647	647	647	647
Total Existing & Committed Resources	19,525	19,083	18,191	17,952
Surplus/Deficit	-2,232	-3,402	-5,178	-7,161
Nondispatchable Efficiency & Load Mgmt	853	1,362	2,008	2,793
Dispatchable Load Management	617	617	617	617
Assumed Spot Capacity, Seasonal Exchange	1,789	1,789	1,789	1,789
Total Uncommitted	3,259	3,768	4,414	5,199
Surplus/Deficit w/ Uncommitted	1,027	366	-764	-1,962
(Efficiency & Load Mgmt as % of Deficit)	65.9%	58.2%	50.7%	47.6%

San Diego Gas & Electric Service Area, MW				
	2000	2003	2007	2015
Peak Demand	3,884	4,221	4,651	5,357
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	547	577	616	689
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	4,431	4,798	5,267	6,046
Utility-Owned Active Resources	2,403	2,403	2,403	1,973
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	430
PURPA-Qualifying Facility Purchases	348	348	348	348
Self-Generation	59	59	59	59
Bulk Utility Purchases	167	67	67	67
Total Existing & Committed Resources	2,977	2,877	2,877	2,447
Surplus/Deficit	-1,454	-1,921	-2,390	-3,599
Nondispatchable Efficiency & Load Mgmt	238	371	545	762
Dispatchable Load Management	44	44	44	44
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	282	415	589	806
Surplus/Deficit w/ Uncommitted	-1,172	-1,506	-1,801	-2,793
(Efficiency & Load Mgmt as % of Deficit)	19.4%	21.6%	24.6%	22.4%

TABLE 8
ER 96 CAPACITY RESOURCES w/
RESTORED FUNDING DSM

Southern California Edison and Public Power Utilities Integrated Planning Area, MW

	2000	2003	2007	2015
Peak Demand	20,679	22,046	23,577	26,000
Exports Requiring Reserves	210	110	0	0
Reserve Requirements	3,082	3,168	3,250	3,384
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	23,971	25,324	26,827	29,384
Utility-Owned Active Resources	14,923	14,923	14,923	13,203
Utility-Owned Reserve/Retired/Decommissioned	1081	1081	1081	2800
PURPA-Qualifying Facility Purchases	3,694	3,695	3,695	3,695
Self-Generation	596	616	639	645
Bulk Utility Purchases	2,503	2,463	2,171	1,314
Total Existing & Committed Resources	21,716	21,697	21,428	18,857
Surplus/Deficit	-2,255	-3,627	-5,399	-10,527
Nondispatchable Efficiency & Load Mgmt	1,030	1,738	2,628	4,206
Dispatchable Load Management	1,902	1,640	1,641	1,641
Assumed PPU "Self-Resourcing"	528	649	850	1,315
Assumed Spot Capacity, Seasonal Exchange	588	588	588	588
Total Uncommitted	4,048	4,615	5,707	7,750
Surplus/Deficit w/ Uncommitted	1,793	988	308	-2,777
(Efficiency & Load Mgmt as % of Deficit)	130.0%	93.1%	79.1%	55.5%

Southern California Edison Company Service Area, MW

	2000	2003	2007	2015
Peak Demand	19,292	20,577	22,001	24,185
Exports Requiring Reserves	210	110	0	0
Reserve Requirements	2,867	2,942	3,009	3,108
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	22,369	23,629	25,010	27,293
Utility-Owned Active Resources	14,277	14,277	14,277	12,663
Utility-Owned Reserve/Retired/Decommissioned	1081	1081	1081	2694
PURPA-Qualifying Facility Purchases	3,694	3,695	3,695	3,695
Self-Generation	596	616	639	645
Bulk Utility Purchases	2,126	2,126	1,935	1,183
Total Existing & Committed Resources	20,693	20,714	20,546	18,186
Surplus/Deficit	-1,676	-2,915	-4,464	-9,107
Nondispatchable Efficiency & Load Mgmt	988	1,684	2,554	4,112
Dispatchable Load Management	1,893	1,630	1,630	1,630
Assumed Spot Capacity, Seasonal Exchange	588	588	588	588
Total Uncommitted	3,469	3,902	4,772	6,330
Surplus/Deficit w/ Uncommitted	1,793	987	308	-2,777
(Efficiency & Load Mgmt as % of Deficit)	171.9%	113.7%	93.7%	63.1%

TABLE 8
ER 96 CAPACITY RESOURCES w/
RESTORED FUNDING DSM

Los Angeles Department of Water and Power Service Area, MW

	2000	2003	2007	2015
Peak Demand	5,809	5,993	6,232	6,639
Exports Requiring Reserves	92	41	41	41
Reserve Requirements	1,165	1,180	1,215	1,286
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	7,066	7,214	7,488	7,966
Utility-Owned Active Resources	6,743	6,743	6,743	6,743
Utility-Owned Reserve/Retired/Decommissioned	373	373	373	373
PURPA-Qualifying Facility Purchases	1	1	1	1
Self-Generation	242	254	259	263
Bulk Utility Purchases	696	696	696	591
Total Existing & Committed Resources	7,682	7,694	7,699	7,598
Surplus/Deficit	616	480	211	-368
Nondispatchable Efficiency & Load Mgmt	78	136	196	250
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	78	136	196	250
Surplus/Deficit w/ Uncommitted	694	616	407	-118
(Efficiency & Load Mgmt as % of Deficit)	-12.7%	-28.3%	-92.9%	67.9%

Sacramento Municipal Utility District Service Area, MW

	2000	2003	2007	2015
Peak Demand	2,466	2,601	2,785	3,183
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	346	349	355	378
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	2,812	2,950	3,140	3,561
Utility-Owned Active Resources	1,133	1,123	1,097	1,093
Utility-Owned Reserve/Retired/Decommissioned	900	900	900	900
PURPA-Qualifying Facility Purchases	0	0	0	0
Self-Generation	0	0	0	0
Bulk Utility Purchases	597	597	497	457
Total Existing & Committed Resources	1,730	1,720	1,594	1,550
Surplus/Deficit	-1,082	-1,230	-1,546	-2,011
Nondispatchable Efficiency & Load Mgmt	165	253	351	423
Dispatchable Load Management	25	32	36	45
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	190	285	387	468
Surplus/Deficit w/ Uncommitted	-892	-945	-1,159	-1,543
(Efficiency & Load Mgmt as % of Deficit)	17.6%	23.2%	25.0%	23.3%

TABLE 8
ER 96 CAPACITY RESOURCES w/
RESTORED FUNDING DSM

Imperial Irrigation District, MW

	2000	2003	2007	2015
Peak Demand	750	812	895	1,058
Exports Requiring Reserves	0	0	0	0
Reserve Requirements	115	122	134	159
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	865	934	1,029	1,217
Utility-Owned Active Resources	602	603	603	603
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	0
PURPA-Qualifying Facility Purchases	0	0	0	0
Self-Generation	0	0	0	0
Bulk Utility Purchases	179	33	33	33
Total Existing & Committed Resources	781	636	636	636
Surplus/Deficit	-84	-298	-393	-581
Nondispatchable Efficiency & Load Mgmt	0	0	0	0
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	0	0	0	0
Surplus/Deficit w/ Uncommitted	-84	-298	-393	-581
(Efficiency & Load Mgmt as % of Deficit)	0.0%	0.0%	0.0%	0.0%

California Department of Water Resources, MW

	2000	2003	2007	2015
Peak Demand	728	728	728	728
Exports Requiring Reserves	624	624	624	624
Reserve Requirements	200	200	200	200
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	1,552	1,552	1,552	1,552
Utility-Owned Active Resources	1,148	1,148	1,148	1,148
Utility-Owned Reserve/Retired/Decommissioned	0	0	0	0
PURPA-Qualifying Facility Purchases	1	1	1	1
Self-Generation	0	0	0	0
Bulk Utility Purchases	166	166	166	100
Total Existing & Committed Resources	1,315	1,315	1,315	1,249
Surplus/Deficit	-237	-237	-237	-303
Nondispatchable Efficiency & Load Mgmt	0	0	0	0
Dispatchable Load Management	0	0	0	0
Assumed Spot Capacity, Seasonal Exchange	0	0	0	0
Total Uncommitted	0	0	0	0
Surplus/Deficit w/ Uncommitted	-237	-237	-237	-303
(Efficiency & Load Mgmt as % of Deficit)	0.0%	0.0%	0.0%	0.0%

TABLE 8
ER 96 CAPACITY RESOURCES w/
RESTORED FUNDING DSM

Total Three Investor-Owned Utilities, (MW) PG&E, EDISON, SDG&E

	2000	2003	2007	2015
Peak Demand	41,152	43,473	46,222	50,747
Exports Requiring Reserves	1,269	1,168	1,015	995
Reserve Requirements	6,136	6,271	6,409	6,710
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	48,557	50,912	53,646	58,452
Utility-Owned Active Resources	31,639	31,185	30,284	27,989
Utility-Owned Reserve/Retired/Decommissioned	2,423	2,800	3,615	5,821
PURPA-Qualifying Facility Purchases	6,994	6,995	6,995	6,995
Self-Generation	1,622	1,654	1,686	1,704
Bulk Utility Purchases	2,940	2,840	2,649	1,897
Total Existing & Committed Resources	43,195	42,674	41,614	38,585
Surplus/Deficit	-5,362	-8,238	-12,032	-19,867
Nondispatchable Efficiency & Load Mgmt	2,079	3,417	5,107	7,667
Dispatchable Load Management	2,554	2,291	2,291	2,291
Assumed Spot Capacity, Seasonal Exchange	2,377	2,377	2,377	2,377
Total Uncommitted	7,010	8,085	9,775	12,335
Surplus/Deficit w/ Uncommitted	1,648	-153	-2,257	-7,532
(Efficiency & Load Mgmt as % of Deficit)	86.4%	69.3%	61.5%	50.1%

Total Six Large Utilities, (MW) PG&E, SDG&E, EDISON, LADWP, SMUD, IID

	2000	2003	2007	2015
Peak Demand	50,177	52,879	56,134	61,627
Exports Requiring Reserves	1,361	1,209	1,056	1,036
Reserve Requirements	7,762	7,922	8,113	8,533
Exports Not Requiring Reserves	0	0	0	0
Total Capacity Requirements	59,300	62,010	65,303	71,196
Utility-Owned Active Resources	40,117	39,654	38,727	36,428
Utility-Owned Reserve/Retired/Decommissioned	3,696	4,073	4,888	7,094
PURPA-Qualifying Facility Purchases	6,995	6,996	6,996	6,996
Self-Generation	1,864	1,908	1,945	1,967
Bulk Utility Purchases	4,412	4,166	3,875	2,978
Total Existing & Committed Resources	53,388	52,724	51,543	48,369
Surplus/Deficit	-5,912	-9,286	-13,760	-22,827
Nondispatchable Efficiency & Load Mgmt	2,322	3,806	5,654	8,340
Dispatchable Load Management	2,579	2,323	2,327	2,336
Assumed Spot Capacity, Seasonal Exchange	2,377	2,377	2,377	2,377
Total Uncommitted	7,278	8,506	10,358	13,053
Surplus/Deficit w/ Uncommitted	1,366	-780	-3,402	-9,774
(Efficiency & Load Mgmt as % of Deficit)	82.9%	66.0%	58.0%	46.8%

TABLE 8
ER 96 CAPACITY RESOURCES w/
RESTORED FUNDING DSM

Detail of Small Public Power Utilities, MW

	2000	2003	2007	2015
Total Capacity Requirements	**5,106**	**5,342**	**5,726**	**6,447**
NCPA	685	717	767	872
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Riverside	426	426	401	227
Vernon	104	104	44	44
Energy Efficiency	**36.7**	**41.8**	**50.1**	**75**
NCPA	6	8	9	17
City of Redding	2	2	2	3
City of Santa Clara	1	2	3	4
Modesto Irrigation District	9	5	2	1
Turlock Irrigation District	0	0	0	0
City of Burbank	0	0	0	0
City of Glendale	0	0	0	0
City of Pasadena	0	0	0	0
Southern California Public Power				
Anaheim	19	25	34	50
Azusa	0	0	0	0
Banning	0	0	0	0
Colton	0	0	0	0
Riverside	0	0	0	0
Vernon	0	0	0	0

TABLE 8

ER 96 CAPACITY RESOURCES w/ RESTORED FUNDING DSM

Detail of Small Public Power Utilities, MW

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Surplus/Deficit	**-234**	**-587**	**-1,178**	**-2,328**
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Turlock Irrigation District	-12	-38	-75	-222
City of Burbank	69	61	51	-18
City of Glendale	20	9	-5	-27
City of Pasadena	60	81	69	38
Southern California Public Power				
Anaheim	-171	-206	-298	-529
Azusa	4	-15	-31	-33
Banning	4	-3	-10	-15
Colton	-39	-68	-76	-95
Riverside	-165	-204	-287	-548
Vernon	-106	-106	-166	-166

Statewide Capacity Requirements, MW

	2000	2003	2007	2015
Capacity Requirements	64,406	67,352	71,029	77,643
Existing & Committed Resources	58,223	57,437	56,041	52,413
Surplus/Deficit	-6,183	-9,915	-14,988	-25,230
Energy Efficiency	4,938	6,171	8,031	10,751
Other Uncommitted Resources	2,377	2,377	2,377	2,377
Total Uncommitted Resources	7,315	8,548	10,408	13,128
Surplus/Deficit w/Uncommitted	1,132	-1,367	-4,580	-12,102

Statewide Total Excludes CDWR

TABLE 9
***ER 96* STATEWIDE CAPACITY SUPPLY AND DEMAND BALANCE**
UNDER THREE SCENARIOS OF EXPECTED UNCOMMITTED DSM SAVINGS
(MW)

Declining DSM Scenario	2000	2003	2007	2015
Capacity Requirements	64610	67801	71795	78889
Existing & Committed Resources	58223	57437	56041	52413
Surplus/Deficit	-6387	-10364	-15754	-26476
Energy Efficiency	3597.7	3230.8	3023.1	2661
Other Uncommitted Resources	2377	2377	2377	2377
Total Uncommitted Resources	5974.7	5607.8	5400.1	5038
Surplus/Deficit w/Uncommitted	-412.3	-4756.2	-10353.9	-21438

Business As Usual DSM Scenario	2000	2003	2007	2015
Capacity Requirements	64478	67505	71284	78019
Existing & Committed Resources	58223	57437	56041	52413
Surplus/Deficit	-6255	-10068	-15243	-25606
Energy Efficiency	4468.7	5170.8	6366.1	8281
Other Uncommitted Resources	2377	2377	2377	2377
Total Uncommitted Resources	6845.7	7547.8	8743.1	10658
Surplus/Deficit w/Uncommitted	590.7	-2520.2	-6499.9	-14948

Restored Funding with Spillover DSM Scenario	2000	2003	2007	2015
Capacity Requirements	64406	67352	71029	77643
Existing & Committed Resources	58223	57437	56041	52413
Surplus/Deficit	-6183	-9915	-14988	-25230
Energy Efficiency	4937.7	6170.8	8031.1	10751
Other Uncommitted Resources	2377	2377	2377	2377
Total Uncommitted Resources	7314.7	8547.8	10408.1	13128
Surplus/Deficit w/Uncommitted	1131.7	-1367.2	-4579.9	-12102

Statewide Total Excludes CDWR

STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

Preparation of the	**)**	**Docket No. 95-ER-96**
1996 Electricity Report (ER 96)	**)**	
	)	**March 29, 1996**

ORDER NO. 96-0327-02

FINAL ELECTRICITY DEMAND FORECASTS for *ER 96*
(Adopted March 27, 1996)

I. INTRODUCTION

Every two years the California Energy Commission (Commission) is required to adopt forecasts of the future demand for electricity in California for the upcoming 5-, 12-, and 20-year periods. (Public Resources Code sections 25305, 25309.) The forecasts are one of the most important parts of our biennial Electricity Reports. Understanding what future demand is likely to be can help us, for example, to assess the type, amount, costs, and environmental consequences of new powerplants and transmission lines that may be needed; to assist suppliers and customers in estimating the costs of power; and to recommend ways to increase the efficiency of electricity production and use. In addition, the 12-year forecasts are used in the "integrated assessment of need" that is the basis for determining whether new power facilities are needed in our certification proceedings. (Public Resources Code sections 25305(e), 25523(f), 25524(a).) For ***ER 96***, the 12-year period runs from 1995 to 2007.

In this Order, the Energy Commission adopts forecasts of future electricity demand for all of the utilities and other electricity providers in the state. We forecast both "energy consumption," expressed in gigawatt-hours (GWh), which measures electricity consumption over time, and "peak demand," expressed in megawatts (MW), which measures the highest hourly need during the year. The forecasts adopted here shall be included in the draft, draft final, and final ***1996 Electricity Reports*** .[1]

[1] The Commission is required by Public Resources Code Section 25308 to include its "adopted" forecast in the draft final ***ER***. However, we caution that the forecasts we adopt today are not to be used in power facility certification proceedings until the final ***ER 96*** is adopted. By statute, the integrated assessment of need, and not the forecasts in isolation, is to be used as the basis for need determinations in our siting cases. (Public Resources Code Sections 25305(e), 25309(b), 25523(f), 25524.)

II. SUMMARY OF THE FORECASTING PROCEEDINGS FOR *ER 96*

The ***ER 96*** Committee (Commissioner Rohy, Presiding Member, and Commissioner Sharpless, Second Member) has conducted a thorough and open public process to develop the forecasts that we are adopting today. This Order is based on the entire record developed in that process.[2] We appreciate the spirit of cooperation and intellectual discourse that has characterized the parties' and the Committee's deliberations, and we thank the parties for their sincere efforts to resolve disputes without the need for protracted adversarial proceedings.

On May 10, 1995, the full Commission adopted forms and instructions establishing a common forecasting reporting methodology for use in ***ER 96***. (See Public Resources Code section 25301.) The CEC Staff and most of the state's utilities filed demand forecasts on July 14, 1995; those forecasts were distributed to all interested parties and to numerous governmental agencies for their review and comment. (See Public Resources Code sections 25300, 25302 - 25304.) For the larger utilities, Staff prepared an independent forecast; for most of the smaller utilities, Staff reviewed the forecasts submitted by the utilities. On November 21, 1995, the Staff held a workshop on forecast issues at which some issues were resolved and others were identified for hearings. Opening testimony was submitted on December 20, 1995, and rebuttal testimony on January 12, 1996.

On January 12 the Staff also submitted an updated forecast. The only difference between the Staff's July and January forecasts is that the former was calibrated -- tested and adjusted according to historical consumption -- using data from 1980 through 1993, while the latter was calibrated using data from 1980 through 1994. (Rebuttal Testimony of Commission Staff Regarding Electricity Demand Forecast Issues and Recommendations (January 12, 1996) ("Staff Rebuttal Testimony"), p. 1.) Unless otherwise noted, (1) all references to the Staff forecast are to the updated January version; and (2) all references to any forecast are to the forecast for the year 2007, the twelfth year of the 12-year forecast period.

The Committee held a hearing to consider the parties' forecasts on January 25, 1996. The parties presented testimony and were cross-examined, and the Committee discussed all the issues that had been raised concerning the forecasts. Because the Staff and all the major utilities in the state have for more than a decade relied on similar end-use forecasting methods and engaged in joint data-collection activities, there were few disputes about basic forecasting

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[2] Throughout this Order we provide citations to portions of the record that support our determinations. A citation to one part of the record does not necessarily provide a complete list of all the evidence that supports a particular assertion or conclusion.

methodology.[3] Instead, the issues concerned projections of economic variables such as job production and household growth. Following the hearing, the Committee distributed a draft of this Order to the ***ER 96*** parties and participants on February 28, 1996.

III. ADOPTION OF FORECASTS

The Commission's adopted forecasts are set forth in the Tables in Appendix A to this Order; the last page of Appendix A lists the documents in which the adopted forecasts were submitted to the record.[4] Appendix B to this Order summarizes the differences between the forecasts submitted by CEC Staff and the utility for those service areas where the two forecasts differed.

As required by our enabling legislation, we officially adopt forecasts for 5-, 12-, and 20-year forecast periods. The forecasting methodologies developed by our Staff and refined with substantial input from the state's utilities are specifically designed to assess long-term trends. Over periods of time lasting from several years to several decades, year-by-year aberrations and fluctuations tend to cancel each other out; a long-term trend line will be much smoother than actual year-by-year history. In some respects, forecasting methods that are used for planning purposes deliberately ignore short-term fluctuations in order to improve the accuracy of long-term forecasts. (1/25/96 Reporter's Transcript ("RT"), pp. 101 - 102.)[5] As a result, the methods used to develop our adopted forecasts, while the best

[3] End-use models focus specifically on the individual processes and behaviors that actually consume energy, as well as on the broader economic and demographic forces that influence energy consumption. End-use models start from the ground up and develop projections of the future number of people, households, and businesses in a utility service area. Then they project the number and type of energy-using devices that are likely to be used, as well as the energy-consuming characteristics of those devices and the energy-using behavior of the people who use them. All of those projections are in turn based on detailed studies done by experts in the various subject areas. The model "adds up" all of the different energy "consumptions" to produce a forecast. Such models are very time- and data- intensive, but they have proven to be more accurate than the available alternatives.

[4]Where there are smaller utilities that purchase from larger utilities (e.g., Azusa from Southern California Edison [SCE]), we adopt individual forecasts for each utility and we also group all the related utilities into a "planning area" for which another forecast is adopted. In Appendix A, Tables 1 through 6 list our adopted forecasts for each of the service and planning areas discussed in this Order. Tables 7 and 8 summarize the forecasts from Tables 1 through 6 and, in addition, show a statewide summation of the individual service and planning area forecasts. Please note that consideration of load losses that self-generators do not experience may require very minor changes to the adopted forecasts during the resource planning stage of ER 96. (For a more detailed explanation, please see CEC Docket No. 90-ER-92, "Committee Recommendations for Adoption of Electricity Demand Forecasts" (February 5, 1992), pages 17 - 18.)

[5] The utilities use three different kinds of forecasts: very short-run forecasts for periods less than a year, used in assessing operational needs; short-run forecasts covering one to three years, used in revenue and rate studies; and long-run forecasts, covering several years to several decades, used in making resource

available for long-term forecasting, are less reliable as a short-term forecasting tool. Therefore, and as in previous ***ERs***, the forecasts set forth in the Appendices for the years before the fifth year (i.e., before 2000) are not officially adopted and are shown for illustrative purposes only. (See CEC Docket No. 90-ER-92, Committee Recommendations for Adoption of Electricity Demand Forecasts (February 5, 1992), page 17.)

We also direct the Staff to investigate (1) the feasibility of developing additional methods that could more accurately forecast short-term trends, and (2) the desirability of doing so in light of increased competition in the electricity industry. A report on that investigation should be presented to the ***ER 98*** Committee in late fall 1996 as a prelude to the ***ER 98*** Forms and Instructions process.

A. Disputed Forecasts

There were only three service areas for which the Staff and the utility disagreed about which forecast should be adopted: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and Los Angeles Department of Water and Power (LADWP). Staff's forecast for PG&E is lower than the adopted ***ER 94*** forecast, while PG&E's is higher; for Edison, Staff's forecast is virtually the same as the ***ER 94*** forecast, while Edison's is substantially lower. For LADWP, both the Staff and utility forecasts are lower than the ***ER 94*** forecast. (Figures Presented by Commission Staff at the January 25, Demand Forecast Hearing, Figures PG&E-1 and SCE-2.)

1. Pacific Gas and Electric Company

PG&E's energy consumption forecast for the year 2007 is 5,157 GWh higher than the Staff's, a difference of 5.1 percent; the utility's peak demand forecast is 658 MW higher, a difference of 3.3 percent. (Testimony of Commission Staff Providing Electricity Demand Forecast Issues and Recommendations (December 20, 1995) ("Staff Testimony"), pp. 2, 3; Staff Rebuttal Testimony, p. 2.) The difference is due to different projections of persons per household ("PPH"), which affect the residential sector forecast, and different projections of industrial output, which affect the industrial sector forecast. The difference in the industrial sector forecasts accounts for most of the difference between the overall forecasts of PG&E and the Staff. (Staff Testimony, p. 19; Staff Rebuttal Testimony, p. 2.)

a. Residential sector forecast

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acquisition decisions. (1/25/96 RT, p. 23.) The Commission Staff currently uses only the last of the three types. (Id.)

In the residential sector, PG&E uses a PPH projection that is lower than Staff's. (Both Staff and PG&E use the basically the same estimates of future population in the state and the PG&E service area. (1/25/95 RT, pp. 29 - 30.) Dividing population by PPH gives the number of households, which is a primary driver of residential energy consumption in the forecast models. Given the same amount of projected population, PG&E's lower PPH projection results in a higher number of households and thus higher forecasted energy consumption.

Although PPH declined in the 1980s in California and nationwide, and while the downward trend has continued in the rest of the country in the 1990s, in all regions of California persons per household have been rising since 1990. (Staff Testimony, pp. 10 - 12; 1/25/96 RT, pp. 29 - 30.) PG&E's witness agreed with Staff that recent trends in California supported the view that persons per household are increasing, but he argued that the trend will peak and then reverse. (1/25/96 RT, pp. 37 - 38; Pacific Gas and Electric Company, ER 96 Demand Forecast, Revision to Opening Testimony of PG&E Witness (January 25, 1996) ("PG&E Revised Testimony"), p. 2.) PG&E's PPH projection is based on a model that focuses on the age mix of the population; as the population ages, PG&E argues, children will move out of their parents' homes and older citizens will have smaller households. (1/25/96 RT, pp. 34, 36.) Staff, on the other hand, bases its projections primarily on the ethnic mix of the population. Staff notes that in recent years the California population has seen substantial increases in immigrants from Central and South America and from Southeast Asia who, so far, have tended to have households larger than average. (Staff Testimony, pp. 10 - 12.) Moreover, an aging population could just as easily result in increased PPH, as grandparents move back into their children's homes for health and economic reasons. (1/25/96 RT, pp. 38 - 39.)

We are not entirely comfortable with the approach of either PG&E or the Staff. As the PG&E witness stated, all relevant factors, such as both the age and ethnic makeup of the state's population, should be considered. (1/25/96 RT, pp. 34 - 35, 45 - 46.) We therefore expect that Staff will improve its PPH projections for the ***ER 98*** forecast. That said, however, we believe that the Staff projection is more credible. For one thing, while Staff shows PPH increasing throughout the forecast period (although at a declining rate of increase) and PG&E shows a rise then a decline, PG&E's PPH projection for the year 2007 is actually higher than the Staff's: 2.89 PPH for PG&E's versus 2.86 for Staff. (Staff's PPH projection for the year 2015 is 2.889.) (CEC Staff, California Energy Demand: 1995 - 2005, Vol. III, p. 4-19; PG&E Revised Testimony, p. 2; 1/25/96 RT, pp. 37 - 38, 51.) Thus for the critical 12-year forecast PG&E's projection actually supports the Staff. Most important, the PG&E witness did not know whether PG&E's PPH projection was based on national data or California-specific data. (1/25/96 RT, p. 59.) Staff's projection is based on California data (id., pp. 29 - 31), and all other things being equal, such data is preferable for a California forecast. (Id., pp. 35 - 36.)

b. **Industrial sector forecast**

PG&E and the Staff have generally similar views about the likely trends in the Northern California economy during the forecast period, but PG&E forecasts substantially greater production than does Staff in three specific industries: petroleum refining, machinery (also called non-electrical equipment), and electrical equipment. (PG&E Revised Testimony, p. 1.) We prefer the Staff forecast for several reasons. First, the PG&E industrial sector forecast shows a 13.8 percent consumption increase from 1994 to 1995; PG&E acknowledged that such a jump is unrealistic (Staff described it as "an artificial result of model calibration . . . not reflective of actual consumption"). (PG&E Revised Testimony, p. 2; Staff Testimony, p. 21; 1/25/96 RT, pp. 65 - 66.) That error carries through all the forecast years and causes the forecast to be too high; indeed, PG&E is preparing a revised industrial forecast that will be lower. (1/25/96 RT, pp. 63 - 64.) Second, in the electrical equipment industry, Staff projects continuation of the current trend of increasing energy efficiency (and thus less energy used per unit of output), while PG&E projects a reversal of the current trend. (Staff Testimony, p. 19.) We agree with Staff that there is no reason to expect a reversal of the historic trend, at least during the ***ER 96*** forecast period. Third, PG&E appears to believe that the recent trend in increasing petroleum refinery production will continue to increase, but we agree with Staff that there are good reasons to expect that trend to peak soon: California refineries are operating at close to capacity, and increasing environmental constraints will limit refinery growth. (Staff Testimony, p. 20; 1/25/96 RT, pp. 70 - 71.) As our most recent ***Fuels Report*** states, "with a utilization rate now at 95 percent, there is limited capability to increase product output on a sustained basis." (CEC, ***1995 Fuels Report***, p. 26 of Committee Draft.) Finally, PG&E's projections for all three industries are statewide; Staff's projections are for Northern California. (1/25/96 RT, pp. 67 - 68.) Again, all other things being equal, the more area-specific the projection, the better.

The Commission therefore adopts the Staff's forecast for PG&E, as shown in Tables 1, 2, 7, and 8 of Appendix A.

2. Southern California Edison Company

Edison's energy consumption forecast for the year 2007 is 4,807 GWh lower than the Staff's, a difference of 4.5 percent; the utility's peak demand forecast is 1,848 MW lower, a difference of 8.5 percent. (Staff Testimony, pp. 2, 3; Staff Rebuttal Testimony, p. 2.) The differences are primarily due to different economic and demographic assumptions.

Edison took the unusual position of not recommending adoption of its own forecast. (1/25/96 RT, p. 186.) Instead, Edison recommended that the Staff re-run its forecasting models with certain changes in input data and assumptions.[6] (Id., pp. 186 - 187; Rebuttal Testimony for the ER-96 Committee Hearing on Demand Forecasts (January 12, 1996) ("Edison Rebuttal Testimony"), p. 6.) Moreover, Edison did not use an end-use model but instead relied upon a simple forward trending analysis of the adopted ***ER 94*** forecast for its planning area with adjustments for some input data. (1/25/96 RT 165 - 166.) For both of those reasons, we will not adopt the forecast prepared by Edison.

That leaves the Staff forecast. Edison made two categories of criticisms against the Staff forecast: (1) several suggestions concerning input data related to economic and demographic projections, and (2) comments asserting that the Staff had overlooked various factors in preparing its forecast. (Edison Rebuttal Testimony, pp. 1 - 6; Southern California Edison, CFM 11 Hearing (January 25, 1996) ("Edison Overheads"), pp. 31 - 38.)

The differences between Staff's and Edison's economic and demographic projections all stem from different views about the future health of the Southern California economy. Staff's projections reflect a view that is more optimistic than Edison's for the first five years of the forecast period but that is more pessimistic in the long term. (1/25/96 RT, pp. 117, 120, 128, 188 - 189.) Edison was substantially more concerned about the near-term projections than the long-term ones. (Id., pp. 131 - 133, 135 - 136, 186.)

There appear to be two primary reasons for the differences in the near-term economic and demographic projections. First, Edison explicitly accounts for the effects of a recession before the end of the century, a recession that Edison believes is likely. (Id., pp. 117 - 118, 120.) This is a matter that again reflects the distinction between forecasting for the next few years and forecasting, as we must do, for more than a decade. While a short-run forecast may appropriately attempt

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[6] Actually, what Edison said is that Staff should re-run its model as long as the energy forecasts end up at 91,000 GWh in the year 2000 and 101,000 GWh in the year 2007. (Southern California Edison, CFM 11 Hearing (January 25, 1996) ("Edison Overheads"), p. 39; 1/25/96 RT, pp. 186 - 187.) Edison has expressed concern that forecasts differing substantially from those amounts could be used to determine rates for recovery of such things as the competition transition charge (CTC), and non-bypassable charges for Public Policy Programs like DSM, RD&D, and Renewables, by agencies like the California Public Utilities Commission (CPUC) and the Legislature. (1/25/96 RT, pp. 131 - 133.) We believe we have addressed Edison's concern for the short-term because we have expressly stated (see page 4 above) that the early years of our forecast are for illustrative purposes only. Moreover, we are disinclined to accept any recommendation, whether it concerns the forecast as a whole or a single point of input data, that is made from such a results-oriented perspective. The reliability of forecasts depends on the validity of the methods and the accuracy of the data used to derive them, not on whether the forecast results comport with a party's preconceived notion of what is in its economic interest.

to predict changes in the business cycle, a long-term forecast should assume that the ups and downs will even out. We do not believe that the implicit assumption of no recession (and no boom) in the Staff's forecast is a flaw that needs adjusting for the purposes of our long-term forecasts.

Second, Edison's projections are based on a methodology that directly links population growth with economic growth. (Staff Testimony, pp. 23 - 24.) While those trends used to be closely tied, experience in the 1980s and 1990s indicates that the link is now more complex. (Id., pp. 13 - 14.) For example, during the California recession of the early 1990s, which hit Southern California quite hard, California did lose population to neighboring states but the substantial flow of foreign immigration into the state continued. (Id.)

Therefore, while there are not strong reasons to view one party's economic and demographic projections as clearly superior, on balance the evidence better supports the Staff's projections. We now turn to the criticisms of Staff's forecast that were presented on the day of the hearing (and that were prepared without the benefit of the full technical discussions that took place at the forecast workshop in November (1/25/96 RT, pp. 137 - 138).

First, Edison asserted that Staff had not taken into account the potential effect of military base closures in Southern California. But Edison's estimates of the effects of that "omission" were based on an apples-and-oranges comparison of projections made for the year 2013 with projections made for the year 1998; moreover, Edison acknowledged that its criticism of the Staff had failed to account for the potential effects of conversion of military bases to other uses. (Edison Overheads, p. 31; 1/25/96 RT, pp. 159 - 160.) Second, Edison asserted that Staff had failed to take account of the 1993 federal efficiency standards for refrigerators. (Edison Overheads, p. 32.) Edison was wrong; the effects of those standards are included in the Staff's forecast. (1/25/96 RT, p. 160.) Third, Edison suggested that Staff had erroneously calibrated its forecast to 1994 historical data (Edison Overheads, p. 35), but Edison was again making an apples-and-oranges comparison; the Staff's forecast number that Edison presented was "weather-adjusted" while the historical number to which Edison compared it was not.[7] (1/25/96 RT, pp. 175 - 177.) Fourth, Edison claimed that Staff did not adjust its forecast to take account of the

[7] Before a forecast is published it is "calibrated," which means that it is adjusted according to historical data. In the calibration process, the forecast model is first run to produce a "backcast" for historical years for which actual energy consumption is known. "Weather-adjusting" is a process whereby the effects of weather (e.g., hotter weather means more energy is used for air conditioning) are removed from the historical data against which a forecast is calibrated. Forecasts assume average weather (because over the long term, weather fluctuations will even out), and it is therefore invalid to compare a backcast based on average weather with historical data that reflects non-average weather. (1/25/96 RT, pp. 170 - 177.) In the final step in calibration, the forecast model is adjusted so that subsequent backcasts come as close as possible to the historical data, the assumption being that if the model can do a good job of "predicting" the past it has a reasonable chance of doing so for the future.

recent action of the California Air Resources Board (CARB) amending its Zero Emission Vehicle (ZEV) standards. (Edison Overheads, p. 36.) However, we believe that it is premature, in light of the ongoing debate on ZEVs and the pledge of major automakers to sell substantial numbers of ZEVs during the time period covered by the amended standards, to call for an adjustment of the Staff's forecast here. Fifth, Edison suggested that Staff should rely on a recent forecast by the Metropolitan Water District (MWD) forecasting decreasing pumping load (Edison Overheads, p. 36), but Staff pointed out that MWD has been making a similar forecast for years, based on projections of lower water deliveries, and that it has yet to occur. (1/25/96 RT, p. 182.) The one criticism that appeared to have some potential validity was the suggestion that Staff failed to take account of the federal efficiency standards for fluorescent light bulbs (Edison Overheads, pp. 33 - 34), but Edison was unable to specify with any precision the magnitude of the alleged error. (1/25/96 RT, pp. 161- 168.)

Thus, there may be small flaws in the Staff forecast. However, to demand perfection in any forecast would be to refuse to ever adopt one. Moreover, to make adjustments to the Staff's forecast would take at least one full month.[8] (1/25/96 RT, pp. 58, 189 - 190.) There is no need to spend the time or the Staff resources that such an effort would take. The potential corrections appear to be unnecessary, despite the differences between the forecasts, in light of the revised approach to demand conformance for powerplants that we adopted in ***ER 94*** and the possibility that that approach will be continued in ***ER 96***. We therefore adopt the Staff's forecast for Edison, as shown in Tables 3, 4, 4A, 7, and 8 of Appendix A.

3. Los Angeles Department of Water and Power

LADWP's energy consumption forecast for the year 2007 is 363 GWh higher than the Staff's, a difference of 1.3 percent; the utility's peak demand forecast is 82 MW higher, again a difference of 1.3 percent. (Staff Testimony, pp. 2, 3; Staff Rebuttal Testimony, p. 2.) There is little reason to believe that one forecast is substantially more plausible than the other.

In the residential sector, the forecast difference is due primarily to different PPH projections. Staff projects constantly increasing PPH through the 12-year forecast period, while LADWP projects an increase through the year 2001 and then a decline. (1996 Demand Forecast, Summary of Testimony, Los Angeles

[8] It is not appropriate to adjust a complex end-use forecast by simply adding or subtracting a certain number of gigawatt-hours or megawatts. There are numerous interrelationships among the parts of a forecast and between the energy and peak demand forecasts. While a simple reduction or augmentation is superficially attractive, it is likely to create internal inconsistencies and may lead to even greater inaccuracies than the ones it is attempting to correct. (1/25/96 RT, pp. 26, 56 - 58.)

Department of Water and Power (January 25, 1996) (LADWP Summary), p. 5.) The LADWP witness noted that in the 1980s steeply rising housing prices and an influx of foreign immigration created steadily increasing PPH in the Los Angeles basin, but he asserted that both trends have ended. (1/25/96 RT, pp. 84 - 87.) While those rationales, especially the one concerning housing prices, are plausible, we find the Department's own PPH projections to be implausible because of the dramatic reversal of the trend's direction in the year 2001.

In the industrial sector, LADWP makes less optimistic economic projections than does Staff, but the differences appear to be more a matter of disagreements over historical data than about future economic trends (LADWP's forecast of total employment actually has a higher growth rate than Staff's; the Department's forecast simply starts out lower). (LADWP Summary, p. 8.)

Primarily in order to maintain as much consistency as possible among our forecasts for the different areas of the state, we adopt the Staff's forecasts for LADWP, as shown on Tables 7 and 8 of Appendix A. We do this despite our discomfort at the discrepancy between the historical data for 1995 and the Staff's forecast for that year.[9] Nevertheless, given the essential similarity of the utility's and the Staff's forecasts, we are confident that choosing the Staff's forecast will not create any significant problems.

B. Staff-Utility Agreements On Which Forecast Should Be Adopted

Based on the discussions at the workshop concerning the reasons for differences in forecasts, the Staff recommends adopting the forecast submitted by the Sacramento Municipal Utility District (SMUD) and the lower of the two alternative forecasts submitted by the California Department of Water Resources (CDWR) (the lower forecast is based on the current operating limitations of the State Water Project); conversely, San Diego Gas and Electric Company (SDG&E) recommends adoption of the Staff's forecast. (Staff Testimony, pp. 22, 28 - 29; San Diego Gas and Electric Company Demand Forecast Rebuttal Testimony (January 12, 1995); 1/25/96 RT, p. 6.) We concur with those unopposed recommendations, and adopt the forecasts for SMUD, CDWR, and SDG&E shown in Tables 1, 2, 7, and 8 of Appendix A.

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[9] Indeed, LADWP suggested that the Staff re-calibrate its forecast to 1995 historical data. (1/25/96 RT, p. 81.) Staff explained that doing so would not necessarily remove the discrepancy, because Staff uses a multi-point calibration process in which the backcast is compared to a trend line that goes through many historical years; Staff would use 1995 data by considering it along with historical data from the years 1980 through 1994. (Id., pp. 26, 170 - 177.) In light of the facts that (1) the "discrepancy" may result substantially from comparison of the weather-neutral backcast to non-weather-adjusted 1995 data (id., p. 104) and (2) there is little meaningful difference between the Staff and utility forecasts, it is not necessary to perform another time-consuming calibration.

C. Service Areas For Which Only One Forecast Was Submitted

The Commission Staff does not prepare an independent forecast for most of the smaller municipal utilities in the state. Instead, Staff reviews forecasts submitted by those utilities to ensure that there are no major problems indicated by substantial unexplained divergence from recent trends or from the most recent adopted forecast. (Appendix to Commission Staff December 20, 1995, Demand Forecast Testimony: Analysis of Smaller Municipal Utility Forecasts (December 20, 1995) ("Municipal Appendix"), p. i-2; 1/25/96 RT, p. 7.) Staff presents an unopposed recommendation to adopt (Staff Testimony, pp. 30 - 33; Municipal Appendix, p. i-10; 1/25/96 RT, p. 7), and we hereby adopt, forecasts for the following utilities as shown in the Tables indicated in Appendix A:[10]

- City of Anaheim (3, 4, 4A)
- City of Azusa (3, 4, 4A)
- City of Colton (3, 4, 4A)
- City of Riverside (3, 4, 4A)
- City of Santa Clara (1, 2)
- City of Vernon (3, 4, 4A)
- Imperial Irrigation District ("IID")(5, 6, 7)
- Modesto Irrigation District (1, 2)
- Northern California Power Agency (1, 2)
- Turlock Irrigation District (1, 2)

Staff also reviewed the forecast submitted by the city of Redding and found it reasonable. However, Redding stated that it also intends to prepare a revised forecast reflecting the merging of its electric utility district into the city government and updated economic and demographic assumptions. (Municipal Appendix, pp. i-10, A-5; 1/25/96 RT, p. 8.) That forecast, which Redding indicated would be prepared in late February (1/25/96 RT, pp. 9 -10), was not received in time for consideration in this Order. We will adopt Redding's original, unopposed forecast, as shown in Tables 1 and 2 of Appendix A.

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[10] Forecasts for the Southern California utilities of the cities of Anaheim, Azusa, Colton, Riverside, and Vernon are added to the Edison service area forecast to derive the Edison "planning area" forecast. (Forecasts for the Anza Electric Cooperative, the city of Banning, the Southern California Water Company, and the Arizona Public Service Company (APS) are also included in the Edison planning area forecast. (Staff Testimony, pp. 30 - 33; Municipal Appendix, p. i-1.)) Forecasts for the Northern California utilities of the cities of Redding and Santa Clara, the Modesto and Turlock Irrigation Districts (MID and TID), and the Northern California Power Agency (NCPA) are added to the PG&E service area forecast to derive the PG&E "planning area" forecast. (Municipal Appendix, p. i-1.) NCPA is itself an association of small municipal utilities. (Id., p. i-3.)

For the cities of Burbank, Glendale, and Pasadena (referred to collectively as "BGP") and for those areas of the state not covered by a specific utility forecast (referred to collectively as "Other"), Staff was the only party to prepare a forecast. (1/25/96 RT, pp. 10 - 11.) As there was no opposition to the Staff's forecasts, we adopt them as shown in Tables 5, 6, 7, and 8 of Appendix A.

No party prepared a forecast for the Anza Electric Cooperative, the city of Banning, the Southern California Water Company, or the Arizona Public Service Company (the latter has "fringe" accounts in the Edison planning area). Staff recommends that we adopt the ***ER 94*** forecasts for those small utilities. (Staff Testimony, pp. 30 - 33; 1/25/96 RT, pp. 11 - 13.) We concur; the adopted forecasts are shown in Tables 3, 4, and 4A of Appendix A.

Dated: March 27, 1996

CHARLES R. IMBRECHT Chairman	SALLY RAKOW Vice Chair
JANANNE SHARPLESS Commissioner and Second Member, Member ***1996 Electricity Report*** Committee	DAVID A. ROHY, Ph.D. Commissioner and Presiding ***1996 Electricity Report*** Committee
MICHAEL C. MOORE Commissioner	

APPENDIX A

Adopted Demand Forecasts

Please Note:
Forecasts for the years 1996 - 1999 are not officially adopted
by the California Energy Commission.
They are shown for illustrative purposes only.

TABLE 1 ER 96 Energy Forecasts for PG&E and Northern California Municipal Utilities (GWh)								
Year	PG&E Service Area	NCPA	Redding	Santa Clara	MID	TID	Small/Med Northern California Municipals	SMUD
1980	61,836	1,849	410	1,609	1,197	831	5,896	5,352
1981	63,563	1,947	448	1,697	1,290	837	6,219	5,694
1982	61,753	1,976	432	1,752	1,276	818	6,254	5,673
1983	62,261	2,043	440	1,912	1,347	853	6,595	5,955
1984	66,391	2,183	464	2,112	1,381	903	7,043	6,360
1985	68,532	2,277	482	2,152	1,415	925	7,251	6,882
1986	66,988	2,315	489	2,191	1,431	944	7,370	7,015
1987	71,385	2,391	542	2,223	1,511	1,021	7,688	7,419
1988	74,229	2,486	552	2,319	1,596	1,113	8,066	7,678
1989	76,295	2,606	569	2,355	1,644	1,124	8,298	7,927
1990	78,584	2,684	612	2,402	1,711	1,187	8,596	8,358
1991	78,477	2,768	632	2,330	1,711	1,199	8,640	8,350
1992	80,003	2,872	654	2,328	1,807	1,194	8,855	8,497
1993	80,913	2,848	632	2,257	1,764	1,189	8,690	8,435
1994	80,997	2,912	655	2,216	1,846	1,228	8,857	8,418
1995	82,347	2,888	650	2,363	1,838	1,262	9,001	8,498
1996	83,627	2,917	678	2,387	1,874	1,298	9,154	8,621
1997	84,973	2,948	708	2,411	1,909	1,332	9,308	8,742
1998	86,429	2,977	732	2,435	1,950	1,364	9,458	8,898
1999	87,807	3,013	759	2,459	1,998	1,398	9,627	9,066
2000	89,012	3,066	786	2,484	2,044	1,433	9,813	9,242
2001	90,047	3,103	809	2,509	2,098	1,469	9,988	9,418
2002	91,221	3,170	835	2,534	2,153	1,501	10,193	9,606
2003	92,412	3,234	865	2,559	2,211	1,536	10,405	9,801
2004	93,503	3,293	896	2,585	2,269	1,569	10,612	10,002
2005	94,725	3,347	929	2,611	2,330	1,602	10,819	10,220
2006	95,706	3,398	958	2,637	2,389	1,641	11,023	10,441
2007	96,734	3,451	988	2,663	2,451	1,681	11,234	10,671
2008	97,842	3,508	1,024	2,690	2,513	1,721	11,456	10,909
2009	98,795	3,563	1,057	2,717	2,579	1,762	11,678	11,161
2010	99,547	3,617	1,091	2,744	2,645	1,802	11,899	11,417
2011	100,402	3,674	1,127	2,771	2,709	1,844	12,125	11,667
2012	101,398	3,731	1,161	2,799	2,774	1,885	12,350	11,922
2013	102,346	3,780	1,194	2,827	2,838	1,926	12,565	12,176
2014	103,311	3,829	1,230	2,855	2,905	1,971	12,790	12,429
2015	104,327	3,878	1,264	2,884	2,973	2,013	13,012	12,688
Average Annual Growth Rate %								
1980-1993	2.09	3.38	3.38	2.64	3.03	2.79	3.03	3.56
1993-2000	1.37	1.06	3.16	1.38	2.13	2.70	1.75	1.31
1993-2007	1.28	1.38	3.24	1.19	2.38	2.50	1.85	1.69
1993-2015	1.16	1.41	3.20	1.12	2.40	2.42	1.85	1.87

TABLE 2 ER 96 Peak Demand Forecasts for PG&E and Northern California Municipal Utilities (MW)								
		Noncoincident Service Area Peak Demand						
Year	PG&E Service Area	NCPA	Redding	Santa Clara	MID	TID	Small/Med Northern California Municipals	SMUD
1980	12,923	364	110	270	352	233	1,329	1,574
1981	13,128	384	115	292	345	231	1,367	1,617
1982	11,683	391	103	301	340	215	1,350	1,489
1983	12,706	406	105	331	364	229	1,435	1,641
1984	13,624	431	118	355	362	241	1,507	1,730
1985	13,794	451	122	370	370	242	1,555	1,851
1986	12,990	439	127	363	370	239	1,538	1,798
1987	13,842	482	145	378	399	255	1,659	1,962
1988	15,509	497	154	401	427	291	1,770	2,035
1989	14,792	507	151	404	420	283	1,765	2,090
1990	16,231	559	173	406	477	315	1,930	2,165
1991	15,544	557	176	391	463	307	1,894	2,226
1992	15,534	566	181	379	473	301	1,900	2,262
1993	16,470	575	182	399	479	313	1,948	2,290
1994	16,571	565	185	388	464	298	1,900	2,250
1995	16,624	579	182	391	490	318	1,960	2,277
1996	16,886	586	185	395	502	325	1,993	2,313
1997	17,157	597	191	399	515	334	2,036	2,347
1998	17,450	607	196	403	529	340	2,075	2,381
1999	17,730	617	202	407	543	345	2,114	2,420
2000	17,976	630	209	411	557	352	2,159	2,466
2001	18,188	641	215	415	576	358	2,205	2,510
2002	18,428	655	221	419	591	362	2,248	2,556
2003	18,675	669	229	423	607	369	2,297	2,601
2004	18,900	681	237	428	623	376	2,345	2,647
2005	19,148	692	245	432	639	383	2,391	2,693
2006	19,353	703	253	436	656	392	2,440	2,739
2007	19,570	714	261	441	673	399	2,488	2,785
2008	19,803	726	270	445	690	407	2,538	2,832
2009	20,009	738	279	449	707	415	2,588	2,880
2010	20,176	749	287	455	725	423	2,639	2,930
2011	20,361	761	296	459	741	432	2,689	2,976
2012	20,572	773	305	464	757	440	2,739	3,024
2013	20,776	784	314	468	773	448	2,787	3,072
2014	20,981	795	323	473	790	456	2,837	3,121
2015	21,205	807	332	478	807	465	2,889	3,183
Average Annual Growth Rate %								
1980-1993	1.88	3.58	3.95	3.05	2.40	2.30	2.98	2.93
1993-2000	1.26	1.31	2.00	0.42	2.18	1.69	1.48	1.06
1993-2007	1.24	1.56	2.61	0.72	2.46	1.75	1.76	1.41
1993-2015	1.16	1.55	2.77	0.82	2.40	1.82	1.81	1.51

TABLE 3
ER 96 Energy Forecasts
for SCE and Southern California Small/Medium Municipal Utilities
(GWh)

Year	SCE Planning Area	Anaheim	Azusa	Banning	Colton	Riverside	Vernon	Anza	SoCal Water	APS	Southern California Municipals	SCE Service Area
1980	59,581	1,740	169	64	108	1,023	1,222	16	60	7	4,409	55,172
1981	61,608	1,797	152	47	114	1,052	1,177	17	66	8	4,429	57,179
1982	59,428	1,717	150	62	113	1,002	1,098	16	70	8	4,237	55,191
1983	62,035	1,828	144	63	118	1,031	992	18	70	9	4,273	57,762
1984	66,691	1,950	155	67	130	1,115	1,030	23	72	9	4,551	62,140
1985	68,375	1,991	160	69	133	1,146	1,093	21	79	10	4,702	63,673
1986	69,757	2,037	167	65	141	1,179	1,113	21	39	10	4,772	64,985
1987	73,213	2,115	179	72	154	1,231	1,125	23	86	11	4,996	68,217
1988	76,480	2,168	184	79	172	1,402	1,111	23	89	13	5,242	71,238
1989	78,677	2,221	190	88	193	1,435	1,127	25	98	14	5,390	73,287
1990	81,975	2,267	192	95	198	1,467	1,044	28	122	15	5,428	76,547
1991	80,623	2,174	194	98	194	1,503	1,019	29	101	14	5,326	75,297
1992	82,304	2,290	185	92	198	1,533	1,043	29	118	16	5,504	76,800
1993	81,120	2,247	187	99	213	1,543	1,030	30	121	17	5,487	75,633
1994	83,494	2,289	188	103	209	1,552	1,032	31	124	17	5,545	77,949
1995	86,246	2,356	189	107	231	1,586	1,030	32	128	17	5,676	80,570
1996	88,206	2,397	191	110	243	1,627	1,030	33	130	17	5,778	82,428
1997	90,339	2,444	193	113	252	1,669	1,030	34	133	17	5,885	84,454
1998	92,492	2,499	195	117	298	1,717	1,030	35	136	17	6,043	86,448
1999	94,597	2,554	197	120	305	1,759	1,030	36	139	17	6,157	88,440
2000	96,816	2,608	199	123	316	1,798	1,030	37	142	17	6,270	90,546
2001	99,137	2,664	201	126	324	1,839	1,030	37	145	17	6,382	92,755
2002	101,057	2,718	203	129	332	1,883	1,030	38	148	17	6,498	94,559
2003	103,419	2,773	205	131	339	1,925	1,030	39	151	17	6,610	96,809
2004	105,580	2,829	206	134	348	1,966	1,030	39	154	17	6,723	98,857
2005	107,391	2,887	207	137	355	2,006	1,030	40	157	17	6,836	100,555
2006	109,289	2,946	208	140	362	2,044	1,030	40	161	17	6,948	102,341
2007	110,731	3,004	209	142	369	2,083	1,030	41	165	17	7,061	103,670
2008	112,489	3,065	210	144	377	2,124	1,030	41	169	17	7,177	105,312
2009	113,770	3,128	211	147	384	2,163	1,030	42	173	17	7,295	106,475
2010	115,118	3,190	212	149	392	2,200	1,030	42	177	17	7,409	107,709
2011	116,439	3,255	213	151	399	2,238	1,030	42	181	17	7,526	108,912
2012	117,668	3,323	214	153	407	2,276	1,030	42	185	17	7,648	110,019
2013	118,954	3,394	215	155	416	2,314	1,030	43	189	17	7,774	111,180
2014	120,260	3,467	217	157	424	2,354	1,030	43	193	17	7,903	112,357
2015	121,608	3,542	218	160	433	2,396	1,030	43	197	17	8,036	113,572
Average Annual Growth Rate %												
1980-1993	2.40	1.99	0.78	3.41	5.36	3.21	-1.31	4.95	5.54	7.06	1.70	2.46
1993-2000	2.56	2.15	0.89	3.15	5.78	2.21	0.00	3.04	2.31	0.00	1.92	2.60
1993-2007	2.25	2.10	0.80	2.61	4.01	2.17	0.00	2.26	2.24	0.00	1.82	2.28
1993-2015	1.86	2.09	0.69	2.19	3.28	2.02	0.00	1.68	2.24	0.00	1.75	1.87

TABLE 4
ER 96 Peak Demand Forecasts
for SCE and Southern California Small/Medium Municipal Utilities
(MW)

		Noncoincident Service Area Peak									
Year	SCE Planning Area	Anaheim	Azusa	Banning	Colton	Riverside	Vernon	Anza	SoCal Water	APS	Southern California Municipals	SCE Service Area
1980	12,926	408	44	17	29	332	238	4	15	2	1,088	11,838
1981	13,763	431	41	13	31	338	233	5	16	2	1,110	12,653
1982	13,167	410	44	17	30	317	238	4	17	2	1,078	12,088
1983	13,606	422	43	17	31	310	190	5	17	2	1,037	12,570
1984	15,384	483	43	18	35	352	186	6	17	2	1,142	14,242
1985	14,810	457	47	18	35	342	191	6	19	2	1,116	13,694
1986	14,875	471	46	18	39	315	194	6	9	2	1,100	13,774
1987	15,085	471	46	18	40	337	190	6	21	3	1,132	13,953
1988	16,420	493	50	21	47	385	190	6	22	3	1,217	15,203
1989	16,030	481	50	24	54	392	194	7	24	3	1,229	14,801
1990	17,753	523	48	25	54	431	182	7	30	4	1,303	16,449
1991	16,866	491	47	26	53	423	173	8	24	3	1,247	15,619
1992	18,550	530	48	25	57	475	179	8	29	4	1,355	17,195
1993	16,624	458	43	26	57	432	174	8	29	4	1,231	15,393
1994	18,364	514	49	27	59	467	178	8	30	4	1,336	17,028
1995	18,407	518	47	28	61	443	178	9	31	4	1,319	17,088
1996	18,842	528	48	29	64	455	178	9	31	4	1,345	17,498
1997	19,297	538	48	30	79	466	178	9	32	4	1,385	17,912
1998	19,752	549	49	31	81	480	178	9	33	4	1,414	18,338
1999	20,204	560	50	32	83	492	178	10	34	4	1,442	18,762
2000	20,679	571	51	33	85	503	178	10	34	4	1,468	19,210
2001	21,152	583	51	33	87	515	178	10	35	4	1,496	19,656
2002	21,553	594	52	34	89	527	178	10	36	4	1,524	20,028
2003	22,046	606	53	35	90	538	178	10	37	4	1,551	20,495
2004	22,495	619	53	36	93	549	178	10	37	4	1,578	20,917
2005	22,869	632	53	36	94	561	178	11	38	4	1,607	21,262
2006	23,263	645	54	37	96	571	178	11	39	4	1,634	21,629
2007	23,577	659	54	38	97	583	178	11	40	4	1,664	21,913
2008	23,949	674	54	38	99	594	178	11	41	4	1,692	22,257
2009	24,237	688	54	39	101	605	178	11	42	4	1,722	22,515
2010	24,540	704	55	40	101	616	178	11	43	4	1,751	22,789
2011	24,837	719	55	40	103	626	178	11	44	4	1,780	23,057
2012	25,112	737	55	41	104	637	178	11	45	4	1,812	23,300
2013	25,403	755	56	41	106	648	178	11	46	4	1,844	23,558
2014	25,694	774	56	42	108	658	178	11	47	4	1,877	23,817
2015	26,000	793	56	42	110	669	178	11	48	4	1,911	24,089
Average Annual Growth Rate %												
1980-1993	1.95	0.90	-0.23	3.32	5.39	2.05	-2.35	5.48	5.20	5.48	0.95	2.04
1993-2000	3.17	3.21	2.33	3.46	5.86	2.20	0.28	3.24	2.30	0.00	2.55	3.22
1993-2007	2.53	2.64	1.63	2.75	3.84	2.16	0.14	2.30	2.32	0.00	2.17	2.55
1993-2015	2.05	2.53	1.22	2.25	3.01	2.01	0.09	1.46	2.32	0.00	2.02	2.06

TABLE 4A
ER 96 Peak Demand Forecasts
for SCE and Southern California Small/Medium Municipal Utilities
(MW)

		Service Area Peak Coincident with SCE Planning Area Peak									
Year	SCE Planning Area	Anaheim	Azusa	Banning	Colton	Riverside	Vernon	Anza	SoCal Water	APS	Southern California Municipals	SCE Service Area
1980	12,926	399	43	16	29	327	189	4	6	2	1,014	11,912
1981	13,763	422	40	12	30	333	185	5	7	2	1,036	12,727
1982	13,167	401	43	16	30	313	189	4	7	2	1,004	12,163
1983	13,606	413	42	16	31	306	151	5	7	2	972	12,635
1984	15,384	473	42	17	35	347	148	6	7	2	1,076	14,308
1985	14,810	447	46	17	34	337	151	6	8	2	1,048	13,762
1986	14,875	461	45	17	39	311	154	6	4	2	1,038	13,837
1987	15,085	461	45	17	40	332	151	6	9	2	1,063	14,022
1988	16,420	483	49	20	47	380	151	6	9	2	1,146	15,275
1989	16,030	471	48	22	54	387	154	7	10	2	1,155	14,875
1990	17,753	512	47	23	53	425	145	7	13	3	1,227	16,526
1991	16,866	480	46	24	52	417	137	8	10	2	1,177	15,689
1992	18,550	519	46	23	56	468	142	8	12	3	1,279	17,271
1993	16,624	448	42	24	57	426	138	8	12	3	1,159	15,465
1994	18,364	503	48	25	59	461	141	8	13	3	1,260	17,104
1995	18,407	507	46	26	61	437	141	9	13	3	1,242	17,164
1996	18,842	517	47	27	63	449	141	9	13	3	1,268	17,574
1997	19,297	527	47	28	79	460	141	9	13	3	1,307	17,990
1998	19,752	537	48	29	80	473	141	9	14	3	1,334	18,417
1999	20,204	548	49	30	82	485	141	10	14	3	1,362	18,843
2000	20,679	559	49	31	84	496	141	10	14	3	1,388	19,291
2001	21,152	570	50	31	86	508	141	10	15	3	1,414	19,738
2002	21,553	582	51	32	88	520	141	10	15	3	1,441	20,111
2003	22,046	594	52	33	89	531	141	10	16	3	1,468	20,579
2004	22,495	606	52	34	92	541	141	10	16	3	1,494	21,001
2005	22,869	619	52	34	93	553	141	11	16	3	1,522	21,347
2006	23,263	632	52	34	95	563	141	11	16	3	1,548	21,715
2007	23,577	645	53	35	96	575	141	11	17	3	1,576	22,001
2008	23,949	659	53	35	98	586	141	11	17	3	1,604	22,346
2009	24,237	674	53	36	100	597	141	11	18	3	1,632	22,605
2010	24,540	689	53	37	100	607	141	11	18	3	1,660	22,880
2011	24,837	704	54	37	102	617	141	11	18	3	1,688	23,149
2012	25,112	721	54	38	103	628	141	11	19	3	1,719	23,394
2013	25,403	739	54	38	105	639	141	11	19	3	1,750	23,653
2014	25,694	757	55	39	107	649	141	11	20	3	1,782	23,912
2015	26,000	776	55	40	109	660	141	11	20	3	1,814	24,186
Average Annual Growth Rate %												
1980-1993	1.95	0.90	-0.23	3.32	5.39	2.05	-2.35	5.48	5.20	5.48	1.03	2.03
1993-2000	3.17	3.21	2.33	3.46	5.86	2.20	0.28	3.24	2.30	0.00	2.61	3.21
1993-2007	2.53	2.64	1.63	2.75	3.84	2.16	0.14	2.30	2.32	0.00	2.22	2.55
1993-2015	2.05	2.53	1.22	2.25	3.01	2.01	0.09	1.46	2.32	0.00	2.06	2.05

TABLE 5
ER 96 Energy Forecasts
for BGP, IID and Other
(GWh)

Year	BGP Planing Area	Burbank	Glendale	Pasadena	Other Planning Area	IID	Other Service Area
1980	2,374	829	730	815	2,678	1,263	1,415
1981	2,453	847	760	845	2,781	1,331	1,450
1982	2,392	812	744	836	2,660	1,232	1,428
1983	2,433	849	802	782	2,595	1,246	1,349
1984	2,648	951	834	863	2,723	1,324	1,399
1985	2,700	925	868	907	2,770	1,380	1,390
1986	2,695	948	841	906	2,759	1,426	1,333
1987	2,754	994	866	894	2,873	1,559	1,314
1988	2,861	1,022	921	919	3,055	1,690	1,365
1989	2,813	1,032	919	863	3,205	1,845	1,360
1990	2,951	1,040	1,025	886	3,310	1,902	1,408
1991	2,758	961	953	845	3,323	1,932	1,391
1992	2,929	997	1,010	923	3,501	2,072	1,429
1993	2,893	969	1,011	918	3,644	2,136	1,508
1994	2,869	961	974	934	3,807	2,243	1,564
1995	2,962	980	1,054	929	3,688	2,340	1,348
1996	2,998	992	1,067	940	3,749	2,439	1,310
1997	3,036	1,005	1,081	952	3,814	2,532	1,282
1998	3,073	1,017	1,093	964	3,881	2,623	1,258
1999	3,110	1,029	1,107	975	3,950	2,717	1,233
2000	3,152	1,043	1,121	988	4,021	2,811	1,210
2001	3,194	1,057	1,136	1,001	4,081	2,888	1,193
2002	3,233	1,070	1,150	1,014	4,143	2,965	1,178
2003	3,273	1,083	1,164	1,026	4,205	3,044	1,161
2004	3,312	1,096	1,178	1,038	4,267	3,123	1,144
2005	3,353	1,109	1,193	1,051	4,329	3,203	1,126
2006	3,392	1,122	1,206	1,064	4,391	3,280	1,111
2007	3,422	1,132	1,217	1,073	4,451	3,354	1,097
2008	3,454	1,143	1,228	1,083	4,513	3,432	1,081
2009	3,484	1,153	1,239	1,092	4,575	3,509	1,066
2010	3,510	1,161	1,248	1,101	4,636	3,585	1,051
2011	3,539	1,171	1,258	1,110	4,696	3,661	1,035
2012	3,567	1,180	1,268	1,118	4,758	3,737	1,021
2013	3,595	1,190	1,278	1,127	4,820	3,814	1,006
2014	3,623	1,199	1,288	1,136	4,881	3,891	990
2015	3,656	1,210	1,300	1,146	4,943	3,968	975
Average Annual Growth Rate %							
1980-1993	1.53	1.21	2.54	0.92	2.40	4.12	0.49
1993-2000	1.23	1.06	1.49	1.06	1.42	4.00	-3.10
1993-2007	1.21	1.12	1.33	1.12	1.44	3.28	-2.25
1993-2015	1.07	1.01	1.15	1.01	1.40	2.86	-1.96

TABLE 6
ER 96 Peak Demand Forecasts
for BGP, IID and Other
(MW)

Year	BGP Planning Area	Noncoincident Service Area Peak			Other Planning Area	Noncoincident Service Area Peak	
		Burbank	Glendale	Pasadena		IID	Other Service Area
1980	593	203	189	197	611	368	243
1981	643	220	211	212	635	382	253
1982	626	210	207	223	607	363	244
1983	641	218	208	219	592	370	222
1984	706	243	232	225	622	396	226
1985	691	230	232	251	632	404	228
1986	692	235	225	243	630	413	217
1987	702	246	228	244	656	421	235
1988	740	250	244	253	697	455	242
1989	673	231	232	259	732	479	253
1990	812	264	284	282	756	545	211
1991	755	238	261	270	759	517	242
1992	806	257	276	284	799	556	243
1993	714	253	276	283	832	567	265
1994	798	251	267	288	869	598	275
1995	764	256	289	287	842	624	237
1996	772	259	293	291	856	651	230
1997	780	263	297	295	871	675	225
1998	788	266	300	299	886	700	221
1999	796	269	304	303	902	725	217
2000	805	273	309	307	918	750	213
2001	811	276	313	312	932	770	210
2002	819	280	317	316	946	791	207
2003	825	283	322	320	960	812	204
2004	833	286	326	324	974	833	201
2005	841	290	330	329	988	854	198
2006	848	293	334	333	1,002	875	195
2007	854	296	338	336	1,016	895	193
2008	860	299	341	340	1,030	915	190
2009	866	301	344	343	1,044	936	187
2010	872	303	347	346	1,058	956	185
2011	877	306	350	349	1,072	976	182
2012	883	308	353	352	1,086	997	179
2013	888	311	357	355	1,100	1,017	177
2014	895	313	360	358	1,114	1,038	174
2015	903	316	363	362	1,129	1,058	171
Average Annual Growth Rate %							
1980-1993	1.44	1.73	2.97	0.60	2.40	3.38	0.65
1993-2000	1.73	1.07	1.59	1.21	1.42	4.08	-3.07
1993-2007	1.29	1.12	1.43	1.27	1.44	3.31	-2.24
1993-2015	1.07	1.01	1.25	1.17	1.40	2.88	-1.97

TABLE 7
ER 96 Energy Forecasts
Planning Area and Statewide
(GWh)

Year	PG&E Service Area	Small/Med Northern California Municipals	SMUD	SCE Planning Area	LADWP	BGP Planning Area	SDG&E	DWR	IID	Other Service Area	Statewide
1980	61,836	5,896	5,352	59,581	17,557	2,374	9,735	3,354	1,263	1,415	168,363
1981	63,563	6,219	5,694	61,608	18,203	2,453	9,894	5,264	1,331	1,450	175,679
1982	61,753	6,254	5,673	59,428	18,060	2,392	9,846	5,192	1,232	1,428	171,258
1983	62,261	6,595	5,955	62,035	18,840	2,433	10,073	2,497	1,246	1,349	173,284
1984	66,391	7,043	6,360	66,691	19,961	2,648	10,757	3,348	1,324	1,399	185,922
1985	68,532	7,251	6,882	68,375	19,931	2,700	11,079	5,410	1,380	1,390	192,930
1986	66,988	7,370	7,015	69,757	20,296	2,695	11,700	5,031	1,426	1,333	193,611
1987	71,385	7,688	7,419	73,213	20,998	2,754	12,442	4,734	1,559	1,314	203,506
1988	74,229	8,066	7,678	76,480	21,829	2,861	13,313	5,928	1,690	1,365	213,439
1989	76,295	8,298	7,927	78,677	22,194	2,813	13,926	7,413	1,845	1,360	220,748
1990	78,584	8,596	8,358	81,975	22,744	2,951	14,797	8,171	1,902	1,408	229,486
1991	78,477	8,640	8,350	80,623	22,550	2,758	14,643	4,400	1,932	1,391	223,764
1992	80,003	8,855	8,497	82,304	22,844	2,929	15,539	4,130	2,072	1,429	228,602
1993	80,913	8,690	8,435	81,120	22,210	2,893	15,451	4,363	2,136	1,508	227,719
1994	80,997	8,857	8,418	83,494	21,790	2,869	15,792	4,947	2,243	1,564	230,971
1995	82,347	9,001	8,498	86,246	23,689	2,962	16,208	5,084	2,340	1,348	237,722
1996	83,627	9,154	8,621	88,206	24,010	2,998	16,641	8,894	2,439	1,310	245,900
1997	84,973	9,308	8,742	90,339	24,363	3,036	17,118	9,237	2,532	1,282	250,932
1998	86,429	9,458	8,898	92,492	24,912	3,073	17,537	9,237	2,623	1,258	255,916
1999	87,807	9,627	9,066	94,597	25,278	3,110	17,943	9,237	2,717	1,233	260,615
2000	89,012	9,813	9,242	96,816	25,668	3,152	18,475	9,237	2,811	1,210	265,435
2001	90,047	9,988	9,418	99,137	26,046	3,194	19,031	9,237	2,888	1,193	270,178
2002	91,221	10,193	9,606	101,057	26,394	3,233	19,563	9,237	2,965	1,178	274,645
2003	92,412	10,405	9,801	103,419	26,730	3,273	20,046	9,237	3,044	1,161	279,528
2004	93,503	10,612	10,002	105,580	27,080	3,312	20,567	9,237	3,123	1,144	284,160
2005	94,725	10,819	10,220	107,391	27,440	3,353	21,118	9,237	3,203	1,126	288,631
2006	95,706	11,023	10,441	109,289	27,783	3,392	21,571	9,237	3,280	1,111	292,833
2007	96,734	11,234	10,671	110,731	28,063	3,422	21,972	9,237	3,354	1,097	296,514
2008	97,842	11,456	10,909	112,489	28,344	3,454	22,371	9,237	3,432	1,081	300,616
2009	98,795	11,678	11,161	113,770	28,608	3,484	22,746	9,237	3,509	1,066	304,054
2010	99,547	11,899	11,417	115,118	28,850	3,510	23,151	9,237	3,585	1,051	307,364
2011	100,402	12,125	11,667	116,439	29,100	3,539	23,510	9,237	3,661	1,035	310,716
2012	101,398	12,350	11,922	117,668	29,359	3,567	23,900	9,237	3,737	1,021	314,160
2013	102,346	12,565	12,176	118,954	29,602	3,595	24,287	9,237	3,814	1,006	317,581
2014	103,311	12,790	12,429	120,260	29,880	3,623	24,670	9,237	3,891	990	321,080
2015	104,327	13,012	12,688	121,608	30,186	3,656	25,070	9,237	3,968	975	324,727
Average Annual Growth Rate %											
1980-1993	2.09	3.03	3.56	2.40	1.82	1.53	3.62	2.04	4.12	0.49	2.35
1993-2000	1.37	1.75	1.31	2.56	2.09	1.23	2.59	11.31	4.00	-3.10	2.21
1993-2007	1.28	1.85	1.69	2.25	1.68	1.21	2.55	5.50	3.28	-2.25	1.90
1993-2015	1.16	1.85	1.87	1.86	1.40	1.07	2.22	3.47	2.86	-1.96	1.63

TABLE 8
ER 96 Peak Demand Forecasts
Planning Area and Statewide
(MW)

Year	PG&E Service Area	Small/Med Northern California Municipals	SMUD	SCE Planning Area	LADWP	BGP Planning Area	SDG&E	DWR	Other Planning Area	Statewide Non-coincident Peak
1980	12,923	1,329	1,574	12,926	4,069	593	2,050	454	611	36,529
1981	13,128	1,367	1,617	13,763	4,364	643	2,113	620	635	38,250
1982	11,683	1,350	1,489	13,167	4,456	626	2,048	651	607	36,077
1983	12,706	1,435	1,641	13,606	4,489	641	2,075	381	592	37,567
1984	13,624	1,507	1,730	15,384	4,926	706	2,379	591	622	41,469
1985	13,794	1,555	1,851	14,810	4,771	691	2,383	709	632	41,196
1986	12,990	1,538	1,798	14,875	4,793	692	2,438	879	630	40,632
1987	13,842	1,659	1,962	15,085	4,992	702	2,416	583	656	41,897
1988	15,509	1,770	2,035	16,420	5,110	740	2,842	979	697	46,103
1989	14,792	1,765	2,090	16,030	4,871	673	2,706	1,179	732	44,838
1990	16,231	1,930	2,165	17,753	5,432	812	3,047	1,363	756	49,488
1991	15,544	1,894	2,226	16,866	5,238	755	3,062	655	759	46,998
1992	15,534	1,900	2,262	18,550	5,430	806	3,340	421	799	49,043
1993	16,470	1,948	2,290	16,624	4,796	714	2,909	800	832	47,383
1994	16,571	1,900	2,250	18,364	5,151	798	3,353	899	869	50,155
1995	16,624	1,960	2,277	18,407	5,423	764	3,397	503	842	50,197
1996	16,886	1,993	2,313	18,842	5,490	772	3,493	631	856	51,276
1997	17,157	2,036	2,347	19,297	5,560	780	3,594	728	871	52,369
1998	17,450	2,075	2,381	19,752	5,664	788	3,682	728	886	53,406
1999	17,730	2,114	2,420	20,204	5,733	796	3,770	728	902	54,397
2000	17,976	2,159	2,466	20,679	5,809	805	3,884	728	918	55,422
2001	18,188	2,205	2,510	21,152	5,873	811	4,002	728	932	56,400
2002	18,428	2,248	2,556	21,553	5,935	819	4,114	728	946	57,326
2003	18,675	2,297	2,601	22,046	5,993	825	4,221	728	960	58,346
2004	18,900	2,345	2,647	22,495	6,055	833	4,337	728	974	59,314
2005	19,148	2,391	2,693	22,869	6,119	841	4,461	728	988	60,239
2006	19,353	2,440	2,739	23,263	6,181	848	4,560	728	1002	61,115
2007	19,570	2,488	2,785	23,577	6,232	854	4,651	728	1016	61,901
2008	19,803	2,538	2,832	23,949	6,282	860	4,736	728	1030	62,759
2009	20,009	2,588	2,880	24,237	6,331	866	4,823	728	1044	63,505
2010	20,176	2,639	2,930	24,540	6,376	872	4,917	728	1058	64,236
2011	20,361	2,689	2,976	24,837	6,425	877	5,002	728	1072	64,967
2012	20,572	2,739	3,024	25,112	6,473	883	5,093	728	1086	65,710
2013	20,776	2,787	3,072	25,403	6,520	888	5,181	728	1100	66,454
2014	20,981	2,837	3,121	25,694	6,576	895	5,268	728	1114	67,215
2015	21,205	2,889	3,183	26,000	6,639	903	5,357	728	1129	68,032
Average Annual Growth Rate %										
1980-1993	1.88	2.98	2.93	1.95	1.27	1.44	2.73	4.45	2.40	2.02
1993-2000	1.26	1.48	1.06	3.17	2.77	1.73	4.21	-1.34	1.42	2.26
1993-2007	1.24	1.76	1.41	2.53	1.89	1.29	3.41	-0.67	1.44	1.93
1993-2015	1.16	1.81	1.51	2.05	1.49	1.07	2.81	-0.43	1.40	1.66

California Energy Commission

electricity report

november 1997

STATE OF CALIFORNIA
ENERGY COMMISSION

Pete Wilson, Governor

P300-97-001