CALIFORNIA'S ELECTRIC SERVICES INDUSTRY:

PERSPECTIVES ON THE PAST, STRATAGIES FOR THE FUTURE

A Report to the
California Public Utilities Commission
by the
Division of Strategic Planning

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Chapter 1

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CHAPTER I

EXECUTIVE SUMMARY

This study begins a dialogue. It was requested by the Commission, which directed the Division of Strategic Planning to undertake a comprehensive review of the "...conditions the electric industry currently confronts, as well as future trends likely to influence the industry."[1]

With this direction in mind, the study weaves together highlights of the past and prospects for the future. The purpose of this study is to provide a foundation on which the Commission and interested parties can examine a range of regulatory strategies designed to better align the state's regulatory program with California's dynamic and increasingly competitive electric services industry. By necessity, that examination must address the state's regulatory compact governing the electric industry, its compatibility with the industry, and whether expectations about the industry's future merit its modification.

For two principal reasons, this study concludes that the state should reform its regulatory program. That reform might include a redefinition of the regulatory compact.

First, California's current regulatory framework, significant portions of which were developed under circumstances which no longer persist, is ill suited to govern today's electric services industry.[2]

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[1] D. 92-09-088, p. 17. The decision further directs the Division to "...examine the Commission's comprehensive set of regulatory programs, and…explore alternatives to the current regulatory approach in light of the conditions and trends identified."

[2] The term "electric services industry" used frequently in this report refers to any service involving the generation, transport, or conservation of electricity, regardless of who provides that service. Providers of electric services include utilities, energy service companies, power marketing agencies, non-utility generators, self-generators, and any other participant in this

CHAPTER I

The fundamental tenets of California's contemporary regulatory compact emerged when the monopoly character of the electric utility industry was secure (Chapter II). The compact came of age during the years of rapid economic growth and impressive productivity gains that characterized the utility industry from 1945 to 1965 (Chapter III). Over time, the means by which the Commission upholds the regulatory compact, and to a lesser extent the compact itself, have changed. Some of the most dramatic change came in response to the economic and financial volatility of the 1970s and 1980s (Chapter IV). Created partly in response to those uncertain times, independent utility providers further propelled change within the industry. The compact was forced to make room for a new partner; regulators responded by modifying the tools used to govern the industry to uphold the compact.

Today, technological change, competitive pressures and emerging market forces exert increasing influence over the structure of the industry and the utility's monopoly position has eroded as a result. At the same time, conditions prompting regulatory reform undertaken in the 1970s no longer persist. Consequently, the Commission should make appropriate reforms in order to establish greater compatibility among the state's compact, the regulation used to uphold it, and the industry they govern.

***Second, the state's current regulatory approach is incompatible with the industry structure likely to emerge in the ensuing decades*.**

Calls for greater customer choice are fueled by the persistent gap between utility average rates and the cost of providing new electric service (Chapter VI). Mounting competition among energy service providers and increased pressure to allow consumers to benefit from competition through greater choice will shape the future structure of the industry (Chapter VIII). Recent reform of federal energy policy will add to the competitive pressures

industry.

utilities already face. As such, the Commission should enact reform to ensure that California is well positioned to benefit from a competitive future. Reform should focus particularly on the need to ensure that consumers benefit equitably from increased competition in the electric services industry.A hybrid regulatory framework currently governs the industry in California. That framework is characterized by regulation keyed to cost-of-service ratemaking principles, and policies tied to market oriented solutions. It poses several problems for the Commission, the industry, and consumers:

The regulatory program blunts incentives for efficient utility operations.

Most industry observers agree that contemporary cost-of-service regulation gives the utility weak incentives to operate efficiently. These incentives were further weakened with the addition of balancing accounts and rate adjustment mechanisms designed principally to protect utilities from the volatile period of the 1970s and 1980s. Consequently, regulation has come to rely more on administrative procedures than on financial incentives as a principal means of fostering efficient utility operation. This reliance leaves the state with an interventionist regulatory structure. The time is ripe to explore alternative regulatory mechanisms designed to better promote efficient utility operations.

The current regulatory program increases the potential for inefficient investment due to unbalanced incentives governing utility investment options.

Markedly different regulatory treatment governs investment in energy efficiency, purchased power, and power plants. As such, the utility faces different, often conflicting, incentives when choosing among resource options. These differences threaten efficient investment in the state's electric infrastructure.

CHAPTER I

The current regulatory approach requires many complex proceedings, which increase administrative costs and threaten the quality of public participation and Commission decisions.

In response to the volatility of past decades, the regulatory framework evolved into a structure composed of a wide array of complex administrative proceedings. Those proceedings impose significant costs and burdens on the Commission, the utilities, and parties appearing before the Commission. The growing number of proceedings leaves the state with a fragmented regulatory process which fosters inconsistency between proceedings and threatens the quality of regulatory outcomes.

The current regulatory approach offers utility management limited incentives and flexibility to respond to competitive pressures.

Increased competition within the industry demands that providers respond and adapt quickly to rapidly changing market conditions. California's regulatory framework for the electric utility industry prohibits utilities from responding effectively to competitive pressures and may therefore reduce the benefits to consumers that might otherwise accompany greater competition.

The current regulatory approach conflicts with the Commission's policy of encouraging competition in the electric services industry.

The incompatibility that currently exists between the electric services industry and the regulatory framework that guides it is likely to increase. In important respects, policies governing the utilities and nonutility service providers differ markedly. Those differences may distort the competitive positions of utilities and nonutility providers; and if left unchecked, the current framework will further distort the playing field on which service providers must compete.

To begin the discussion of reform, the study offers four strategies, each of which addresses the shortcomings of the regulatory framework (Chapter VIII). The four strategies are assessed on the basis of seven criteria: administrative costs and burdens; consumer protection; efficient operation and investment; safety and reliability; efficient pricing; environmental quality and resource diversity; and pursuit of social objectives.

- **Strategy A - Limited Reform**. This strategy relies in a limited way on structural change and looks principally to maintaining the current cost-of-service regulatory model. The most notable features of this strategy include moving to annual rate cases; discontinuing several balancing accounts and rate adjustment mechanisms; replacing the current resource procurement process; and establishing a performance-based ratemaking mechanism for utility natural gas purchases related to electric generation. The regulatory compact's tenets remain intact, but the means used to uphold the compact are modified significantly.

- **Strategy B - The Price Cap Model**. This strategy also retains the regulatory compact's existing tenets, but departs dramatically from the current means employed to uphold the compact. This strategy builds upon the New Regulatory Framework governing California's telecommunications industry; it focuses on enhancing pricing flexibility and severing the link between utility rates and expenses.

- **Strategy C - Limited Customer Choice**. This strategy promotes customer choice by providing access to the competitive market for a limited segment of consumers. For those who choose to remain on the utility system, it offers protection comparable to that currently enjoyed by utility customers. The strategy builds on the core/non-core strategy governing the state's natural gas industry. It redefines the regulatory compact by modifying the utility's exclusive franchise. The utility would provide transmission access to the non-core sector. In return, the utility's duty to serve is substantially modified with respect to those customers electing to take advantage of competitive alternatives in the electric services market.

- **Strategy D - Restructured Utility Industry**. This strategy promotes a competitive market for electric services through divestiture of generation by the state's three major electric investor-owned utilities. The newly formed utilities become common carrier transmission and distribution companies and procure generation services for customers who choose to remain utility customers. The utilities provide open nondiscriminatory access to the transmission and distribution system to customers who choose to procure generation service independent of the utility. The regulatory compact is redefined: utilities no longer enjoy an exclusive retail franchise, nor do they retain the duty to serve customers who elect to procure services independent from the utility.

CHAPTER II

A BRIEF HISTORY OF THE REGULATORY COMPACT

The relationship between the Commission's regulatory programs governing the electric utility industry and the obligations and privileges of the industry's participants is often referred to as a "social contract," or "regulatory compact." The participants to the compact include the Commission; the consumers of energy services; the state's utilities; unregulated energy service providers; and the citizens of California.

Many assert that a reexamination of this "compact" between industry, government and consumers is necessary because in their view the current regulatory approach seems to conflict with the compact's original intent. Still others argue that in many respects the current compact is simply incompatible with the industry it purports to govern.

A brief discussion of the compact's origin and principles is helpful in the attempt to identify the form and extent of any such conflict or incompatibility. A brief look into the compact's historical development also provides a useful context within which to begin crafting alternative regulatory approaches should the Commission determine that the changes facing the electric industry warrant the development of new or modified approaches.

Overview

The core of California's current regulatory compact is anchored in the state Constitution and the Public Utilities Code, which place with the Commission broad authority to "supervise and regulate every public utility in the State and…do all things...necessary and convenient in the exercise of such power and jurisdiction."[3] Yet over the decades, forces external to the Commission have influenced and altered the character of the compact. Notable is the influence exercised by state legislatures, Congress, the courts, structural changes in the economy and other economic events, and technological innovation within the electric industry.

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[3] See Cal. Const., Article XII, Sections 1-8, and P.U. Code, Section 701.

The principal effect of these forces has been two-fold: First, they have prompted the Commission to alter the *means*--the policies and programs--it employs to ensure that the duties and responsibilities contained in the compact are fulfilled. Second, the Commission has responded to these forces in a much more limited fashion by modifying some of the compact's basic tenets. And just as past events have had an influence over the compact, so, too, are the future, and expectations of the future, likely to require the Commission to examine the need for additional modifications. Despite these changes, however, certain of the compact's fundamental tenets endure today and are expected to persist.

The Compact Defined

The roots of the compact run deep in the law and in economic theory.

Built upon a rich history of the common law, culminating most notably in this country with the Supreme Court's ruling in *Munn v Illinois,*[4] businesses whose operations were found to "affect the community at large" were said to be "clothed with a public interest," and could, within limits, be legally regulated. Since *Munn*, the regulatory compact evolved to ensure that regulated utilities do not discriminate either through abuse of the economic power they hold over consumers or by neglecting to offer a minimum quality and quantity of what is today considered a "necessity" service.[5]

Economic considerations soon joined public utility regulation's legal underpinnings. Persuaded that consumers would benefit most by granting an exclusive franchise to produce

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[4] 94 U.S. 113 (1877).

[5] Some contemporary economists question relying on "protection of the public interest" as public utility regulation's overriding guiding principle. See, for example, Joskow, P.L., "Conflicting Public Policy Goals, Changing Economic Constraints and the Future of the Regulatory Compact," p. 20. Presented to a seminar on the regulatory compact sponsored by the California Foundation for the Environment and the Economy, April 1992.

electricity, regulators designated specific service areas within which electric service was limited to a single firm.[6]

The Compact in California

Building on the compact's legal and economic foundations, the actions of this Commission, California's Legislature, the courts, state and federal agencies, and Congress have combined to form four oft-cited elements of what has come to be referred to as the "traditional regulatory compact." Under that compact an investor-owned public utility in California was granted 1) an exclusive retail franchise to serve a specific geographic region; 2) an opportunity to recover prudently incurred expenses; 3) an opportunity to earn a reasonable return on investment; and 4) powers of eminent domain.[7] In return for these privileges, the utility was subject to cost and price regulation by the Commission, and required to provide safe and reliable service to all customers in its service area on a nondiscriminatory basis. This latter feature of the compact is commonly called the utility's "duty," or "obligation" to serve.[8]

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[6] Economists refer to the situation in which service is best provided through one firm as a "natural monopoly." They suggest three conditions under which the "natural monopoly" occurs: 1) a single firm can produce to meet total market demand cheaper than two or more firms; 2) market or demand in relation to the technology of production, or supply, is such that one plant supplies the market efficiently and at least cost; and, 3) efficiencies that cannot be achieved relying on the market are obtained by concentrating production. (See FERC Notice of Proposed Rulemaking, March 16, 1988, p. 22.)

There are however those who refute the notion that the "natural monopoly" character of electric service actually prompted regulation as we know it today. They argue instead that the industry itself sought and achieved regulation as a means of suppressing competition and advancing its own economic self interest. See for example Power Struggle, Rudolph, R. and Ridley, S., New York: Harper & Row, 1986.

[7] See for example, Phillips, Charles F., Jr., The Regulation of Public Utilities, Arlington, Virginia, Public Utilities Reports, Inc., 1988.

[8] For an in-depth discussion of the historical development of the duty to serve, see Harr, Charles and Fessler, Daniel W., The Wrong Side of the Tracks, New York: Simon &

CHAPTER VII

The Commission fulfills its obligations under the compact through a decisionmaking process which attempts to balance the interest of current and future consumers and the financial interest of the utility accepting the duty to serve.

Evolution of the Compact in California

As set forth in the Public Utilities Code, the Commission protects the interest of consumers by ensuring "just and reasonable" rates for utility services rendered.[9] In this fundamental respect, the Commission's goal has not changed.[10] As recently put by the President of the Commission, that goal is "...to promote an infrastructure which will provide fundamental services to all Californians on terms that are equal, adequate and non-discriminatory."[11]

But while this goal remains as an enduring tenet of the compact, the past two decades have seen an evolution in the *means* by which this Commission ensures that the compact is

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Schuster, 1986. The authors trace the origins of the duty to serve to common law decisions of the Court of Common Please in the fifteenth century. They demonstrate that while the duty to serve has most consistently been attached to holders of monopolies, it has other recurrent applications which are totally unrelated to the monopoly status of the provider of the goods or services. In Tudor England the duty was vigorously enforced against inn keepers on the rationale that their institutions were "things of necessity." The modern notions of business affected with a public interest is clearly traceable to these decisions.

9 P.U. Code Section 451. Commissions, including California's, historically relied on prices tied to the utility's embedded cost of service to ensure reasonable rates for consumers and a reasonable opportunity to recover expenses for the regulated utility. In *Hope Natural Gas Co. v. Federal Power Commission*, 320.

10 U.S. 591 (1944), the Supreme Court put to rest a long-standing controversy surrounding the compact when it granted public utility commissions broad discretion to devise the means by which the Commission affords utilities the opportunity to recover reasonably incurred costs.

11 Remarks of CPUC President Daniel Wm. Fessler before the Department of Energy Weatherization Conference, October 22, 1992.

upheld. And to a limited degree, the compact itself has evolved with respect to each of the industries the Commission oversees. A few examples are provided to illustrate the compact's evolution.

Balancing Accounts and Rate Adjustment Mechanisms: Risk Sharing Redefined

In response to inflationary pressures and rapid increases in the cost of fuel, construction, and power plant financing during the 1970s and early 1980s, the Commission instituted balancing accounts and rate adjustment mechanisms. These regulatory tools were principally designed to insulate consumers from excessive rate volatility and utilities from dramatically increased financial risks. By shifting those risks to consumers through these new mechanisms, the Commission altered the means historically used to balance the interests of consumers and utilities called for under the compact as traditionally defined. In the attempt to compensate for this realignment of risk, and bring risk-sharing under the compact back into balance, the Commission became a greater partner in utility decisionmaking and management.[12]

The Diablo Settlement: Cost Recovery Redefined

In 1988, the settlement reached over PG&E's Diablo Canyon nuclear plant further modified the means by which the Commission historically fulfilled its obligations under the traditional regulatory compact. Commission approval of the settlement marks a dramatic shift away from the cost-of-service ratemaking principles long in use by the Commission to govern utility cost recovery.

Rather than base cost recovery on utility expenses, the settlement opts instead for an

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12 The Commission's expanded role vis-a-vis utility management decisionmaking is discussed further in Chapters IV and V.

approach more akin to the cost recovery arrangements offered to qualifying facilities. In contrast to the compact's traditional approach, which looks to the level of prudent investment as its measure of compensation, cost recovery for Diablo Canyon--like that for QFs--is based on plant *performance*; that is, on the plant's ability to deliver service.

PURPA: The Number of Participants to the Compact Increases

With the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) the terms of the compact changed again. PURPA added an additional participant to the compact--the unregulated qualifying facility, or QF. Federal and Commission guidelines implementing PURPA require the state's IOUs to compensate QFs for energy service rendered at prices based on the cost the utility avoids by not producing the service itself.[13]

Implementation of PURPA did not alter the utility's duty to serve, nor did it modify the utility's exclusive retail franchise. The structure of QF contracts, however, did shift to the compact's new participants financial risks traditionally borne by the utility and its customers for the development and delivery of electric services. In return for these risks, the QF receives compensation for energy services delivered to the utility.

The Telecommunications and Natural Gas Industries: Trends for the Future?

The evolution of the compact, and the means used to uphold it, have been most significant in the natural gas and telecommunications industries. Most notable among these are changes to the utility's exclusive franchise under the compact governing both industries, and cost recovery under the compact governing the telecommunications industry.

For natural gas utilities, the compact historically granted the utility an exclusive retail franchise--much like the one enjoyed by electric utilities today--making it the sole provider in

[13] The cost paid to qualifying facilities under PURPA is commonly referred to as the "avoided cost."

its service area. However, on the heels of federal actions designed to increase competition in the market for natural gas services, the Commission, persuaded that the best interest of the state's consumers lay in their ability to exercise choice among providers, modified the compact. It did so by allowing customers to procure gas supplies directly from providers other than the utility within whose franchise the customer resides.[14] In so doing, the Commission significantly redefined the notion of the exclusive franchise once granted to the utility under the terms of the traditional compact.

The telecommunications industry has seen still greater changes in the compact and in the way the Commission affords the utility the opportunity to recover expenses for services rendered. First, the utility's exclusive retail franchise effectively ended with divestiture. Second, with respect to cost recovery, the Commission no longer explicitly oversees utility expenses incurred in the development and delivery of services. Instead, the Commission now looks only to the *prices* the utility may charge for services. Under this "new regulatory framework" governing the telecommunications industry in California, the utility is generally at risk for operating expenses, investment decisions, and sales. The Commission continues to oversee the price the utility may charge for those services.[15]

The Future of the Regulatory Compact

These examples suggest that despite the Commission's enduring obligations under the state Constitution, the means the Commission uses to uphold the regulatory compact, and in a much more limited sense, the compact itself, have evolved. In short, faced with an ever-changing set of challenges, the Commission has time and again turned to a flexible rather than a rigid approach to utility regulation, exploring innovative ways of ensuring compatibility

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14 See, for example, D.90-09-089.

15 See D.89-10-031.

between its regulatory programs and the industry those programs govern.

For example, in 1981, at a symposium convened by the Commission on the subject of industry restructuring, the then President of the Commission expressed his belief that "[a] deregulated approach [to the electric industry] is an alternative worthy of exploration."[16] More than a decade later, that approach is receiving increasingly greater attention in California, across the nation, and in other countries. In 1986, the Commission directed the then Policy and Planning Division to undertake a comprehensive reexamination of the extent to which its regulatory programs meshed with the industry structure of the late 1980s, and with the structure expected to emerge in the 1990s. The report offered the Commission several reforms designed to establish greater compatibility between regulation and the electric industry.[17] Finally, in 1990, recognizing the changing nature of the electric industry from one simply offering electrons, to one focused on energy services, the Commission embraced an innovative pilot program offering performance-based incentives for utility investment in demand-side management.[18] This study reflects this Commission's continuing interest in ensuring compatibility between regulation and the industry it governs.

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16 See comments of John E. Bryson, President, in Energy Utilities: The Next 10 Years, San Francisco: CPUC, July, 1981.

17 Risk, Return, and Ratemaking: A Review of the Commission's Regulatory Mechanisms, Policy and Planning Division, California Public Utilities Commission, October 1, 1986. Appendix B to R.86-01-001.

18 See D.90-08-068 and D.90-12-071.

CHAPTER VII

As discussed in greater detail in Chapter VIII, our study concludes that for a variety of reasons, the Commission should reform the state's regulatory program governing the electric industry. As part of that reform, the Commision should examine the need to modify the regulatory compact. That examination should specifically address the utility's duty to serve in light of the fact that the state has seen the utility's monopoly position erode substantially during the past two decades. Reform offers the Commission the opportunity to bring the regulatory compact and the programs used to uphold the compact better into balance with California's electric industry. Equally significant, reform promises to better position the Commission and the state for the challenges the electric industry will surely bring.

CHAPTER III

1945-1965: THE GLORY DAYS

It is hard to imagine, with the experience of the last twenty years behind us, that there was ever a stable period for the electric utility industry or its regulators. The volatility of fuel and financial markets since the early 1970s has erased the memory of a more stable era, leaving a sense that the conditions affecting the electric utility business are fraught with instability and unpredictability. Coupled with other forces--environmental and safety concerns, pressures for non-utility generation, the belief that utilities are not as efficient as they can be--some observers now view the electric utility industry as a financially risky one.

Yet, looking back to the twenty years following World War II, one finds an electric utility industry which thrived on ideal market and economic conditions. Inflation rates, interest rates, and fuel prices were low and stable. And, as the post-war economy expanded and the United States made electrification a national priority, demand increased. These conditions and technological advances made electric generation a declining cost industry.

In this expanding economy, assisted by a regulatory system which stayed out of the way of evolving utilities, utility stocks were characterized by low risks and steady returns. Electric utility stocks were valued by investors seeking safe, secure equity investments and, because of their security, were much valued as investments for retirement "nest eggs." A review of this stable period provides useful insights for the consideration of future policy options.

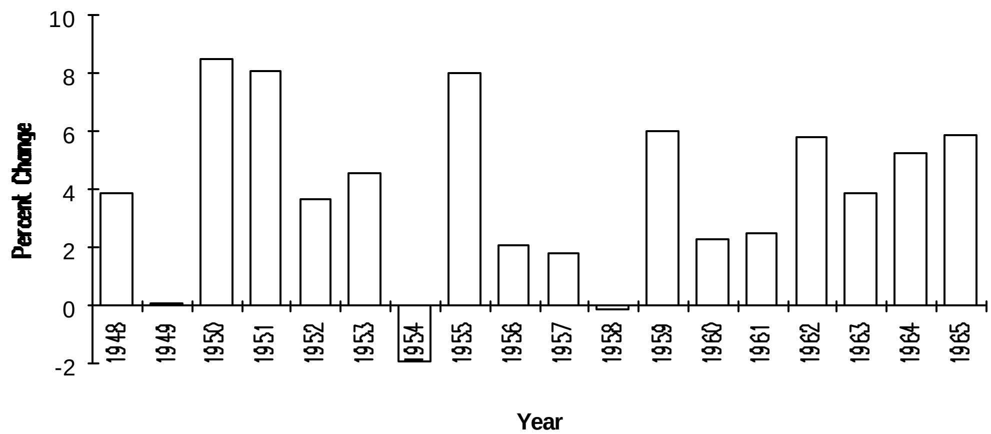
The Economic Setting

The period bounded by the years 1948 to 1965 witnesses dramatic expansions of world economies, especially for the U.S. and California. After World War II, countries rebuild their economies and U.S. efforts are pledged to help rebuild Europe. The Marshall Plan is the best example of this effort; in addition, U.S. resources are assisting Japan in its recovery. The post-war U.S. economy expands further during this period as pent-up demand for consumer goods is released. The result is a tremendous expansion of the U.S. economy. Despite occasional periods of moderate growth, the general trend, expressed best by GNP growth, is an average annual GNP increase of about 2.8% per year between 1948 and 1965

(Figure III-1).

Figure III-1

GNP Growth, 1948-1965

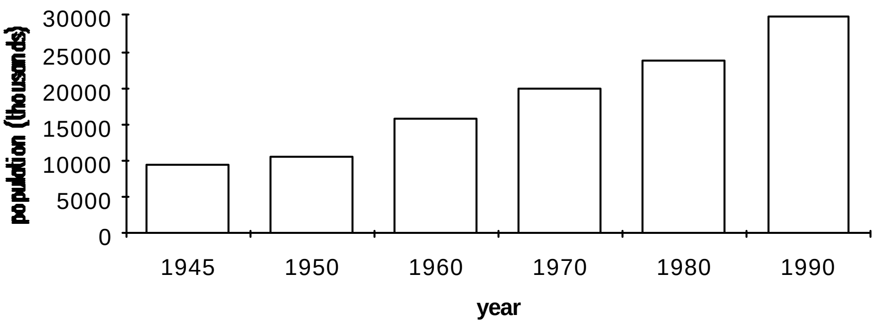


Source: Hyman (1992), page 115.

During the U.S. economic expansion, California also benefits. Southern California becomes the center of the U.S. defense industry as the Cold War expands worldwide. California also becomes a major tourist center, agricultural producer and processor, and a base for light and heavy manufacturing. This results in a dramatic increase in California's population (Figure III-2) and the number and worth of businesses created (Figures III-3 and III-4).

Figure III-2

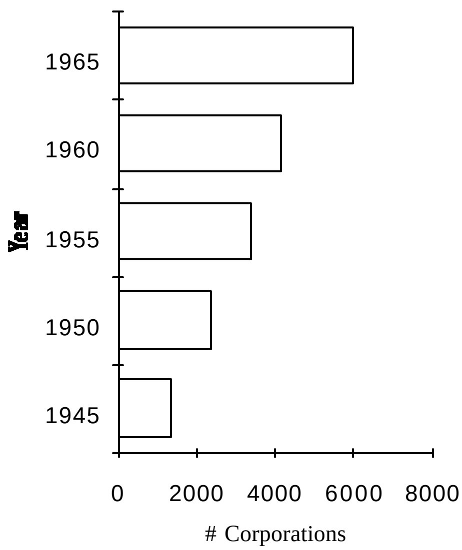
California Population 1945-1990



Source: U.S. Census Bureau.

Figure III-3

California Business Growth



Source: California Statistical Abstract, 1970.

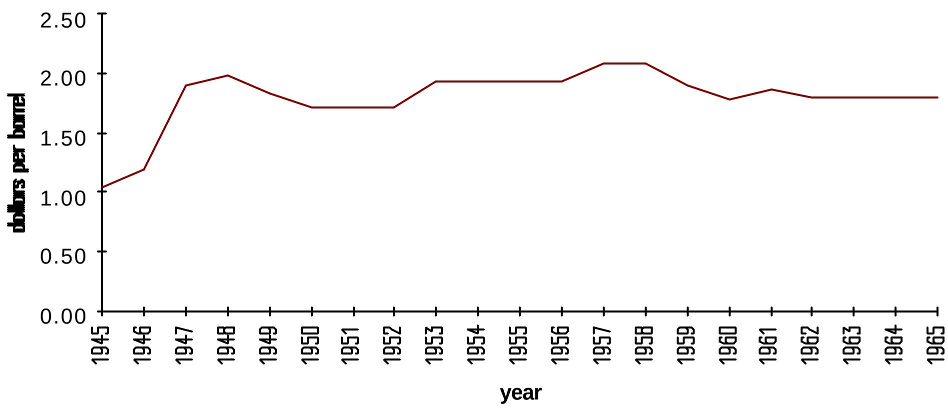
Figure III-4

California Business Revenue Growth

Source: California Statistical Abstract, 1970.

This economic expansion is largely fueled by fossil fuels, especially crude oil. Oil prices are stable and relatively low priced, staying below $2.00 per barrel (Figure III-5). The abundant supply of low-priced oil, especially from the newly tapped fields in the Middle East, makes oil the fuel of choice for most new electric generating plants. PG&E constructs well over 20 fossil fuel units during this period, ranging in size from 52 to 340 megawatts.[19] By 1965, oil and natural gas are used to produce 71% of the electricity generated by California's investor-owned utilities.[20]

Figure III-5
Crude Oil Prices, 1945-1965



Nominal dollars. Source: American Petroleum Institute.

Industry Response

Electric utilities benefit greatly from these stable financial and economic conditions. Demand for electricity is strong during this period. Between 1947 and 1965, national sales of electricity increase at an average annual rate of 9.37%; double-digit demand growth is not unusual (Figure III-6). In California, investor-owned electric utility sales escalate at an annual rate of more than 8.5% between 1950 and 1965 (Figure III-7).

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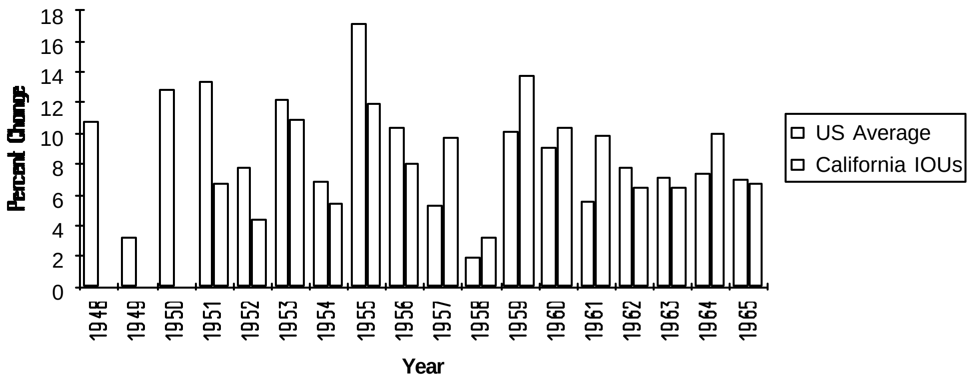
19 List of fossil fuel steam plants supplied by PG&E to the Division of Strategic Planning.

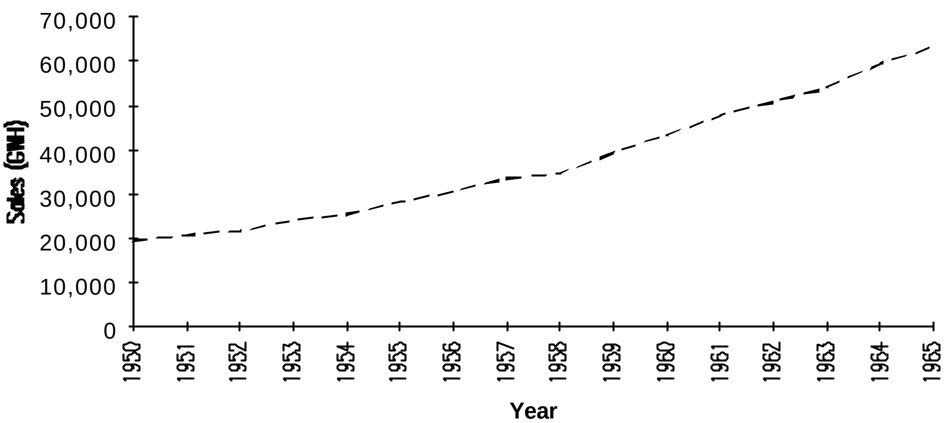
20 Electric generation fuel sources from utility annual reports and FERC form 1, provided in response to Division of Strategic Planning data request, November 3, 1992.

Figure III-6
Electric Utility Sales Growth Rates



Sources: U.S. Average from Hyman (1992), p. 115; IOUs from utility responses to DSP data request, November, 1992.

Figure III-7
California Electric IOU Sales



Source: Utility response to DSP data request, November, 1992.

With rising demand, the need for new generating sources, and the capital to construct them, increases commensurably. By 1947, utility capital expenditures are regularly in the billions of dollars, nationwide (Figure III-8). In California, electric IOU capital expenditures more than triples between 1950 and 1965, growing at an annual rate of over 8.1% (Figure III-9). In addition, technological advances in fossil-fueled generating technologies allow utilities to take advantage of increasing economies of scale.[21] In 1948, there were only two power plants larger than 500 MW in the U.S. By 1972, there were 122 such plants.[22] Utilities gain additional efficiencies in plant operations. The development and use of high voltage electric transmission lines provide access to inexpensive efficiencies in plant operations. Heat rates[23] for power plants decline steadily (Figure III-10). power throughout the country. California uses these transmission lines to gain access to hydroelectric power from the Pacific Northwest and the Colorado River. They also afford California utilities the opportunity to participate in coal facilities located close to coal resources in the Rocky Mountain and Southwest regions of the U.S.. Finally, the development of transcontinental natural gas pipelines link producing regions of Texas and Oklahoma to consumers throughout the country, providing an inexpensive boiler fuel for use in utility thermal generating facilities.

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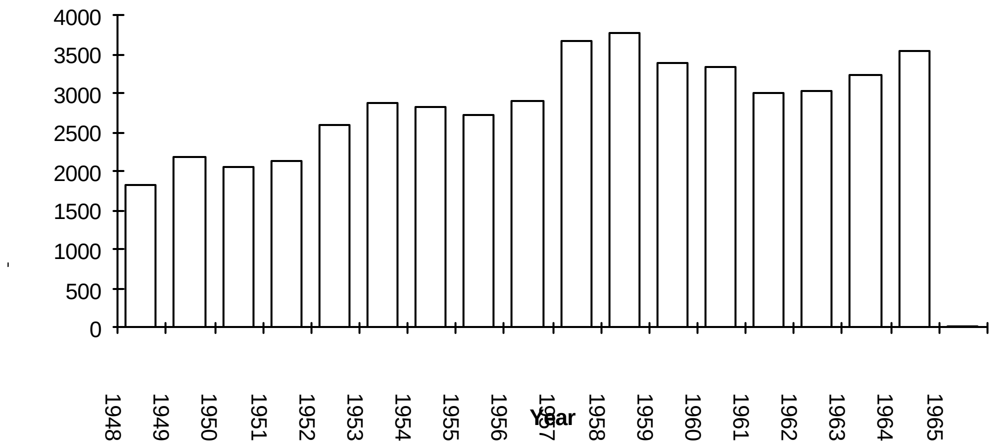
21 The term "economies of scale", also referred to as returns to scale, describes the situation where, due to technological or productivity improvements, average unit costs decline with increased size. In other words, a business can double the size of a plant or facility without doubling the cost. Resource, the energy "encyclopedia" created by PG&E has a good discussion of economies of scale as they relate to electricity (pages 158-159).

22 Inventory of Power Plants, U.S. Energy Information Agency, cited in Gold At the End of the Rainbow? A Perspective on the Future of the Electric Utility Industry. Kaufman, et al. Washington DC: Congressional Research Service, Dec. 31, 1984, p. 218.

23 A heat rate is a measure of the fuel efficiency of electric generation, expressed as BTUs per kilowatt-hour.

Figure III-8

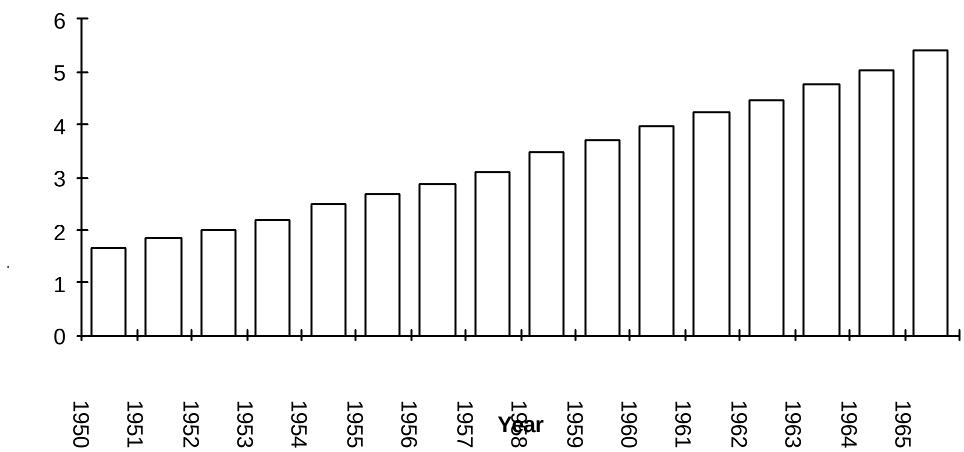
U.S. Electric Utility Incremental Capital Spending, 1948-1965



Nominal dollars. Source: Hyman (1992), page 115.

Figure III-9

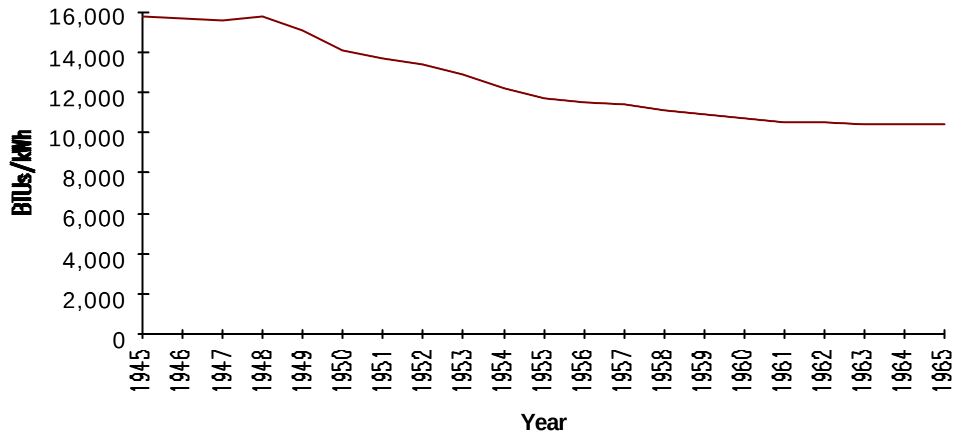
Total Investment by California IOUs



Source: California Statistical Abstract 1970, Table K-3, p. 242.

Figure III-10

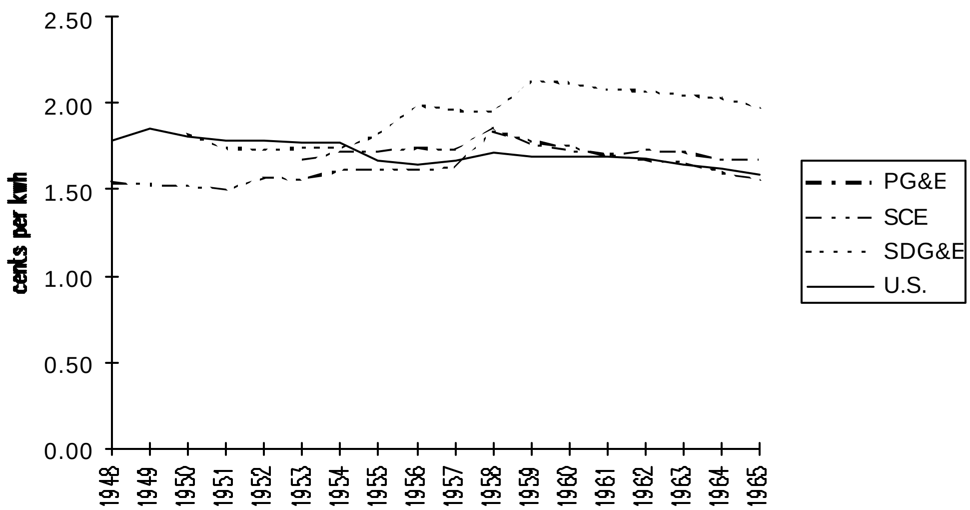
U.S. Average Electric Heat Rates



Source: Historical Statistics of the United States, U.S. Department of Commerce.

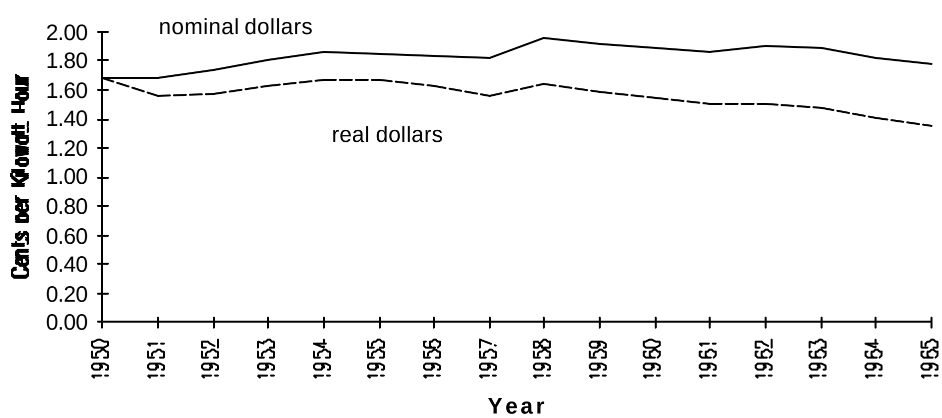
In short, low input costs and increased production efficiencies keep system average electricity rates stable or declining (Figure III-11). In California, rates hover around 1.8 cents per kilowatt-hour from 1950 through 1965 in nominal terms and decline in real terms (Figure III-12). Steady demand growth and low production costs keep electric utility financial health strong, both in California and across the country (Figure III-13).

Figure III-11
Average Electricity Rates



Nominal dollars. Source: U.S. from Hyman (1992), page 115; California IOUs from utility responses to DSP data request, November, 1992. PG&E data unavailable prior to 1953; SDG&E unavailable prior to 1950.

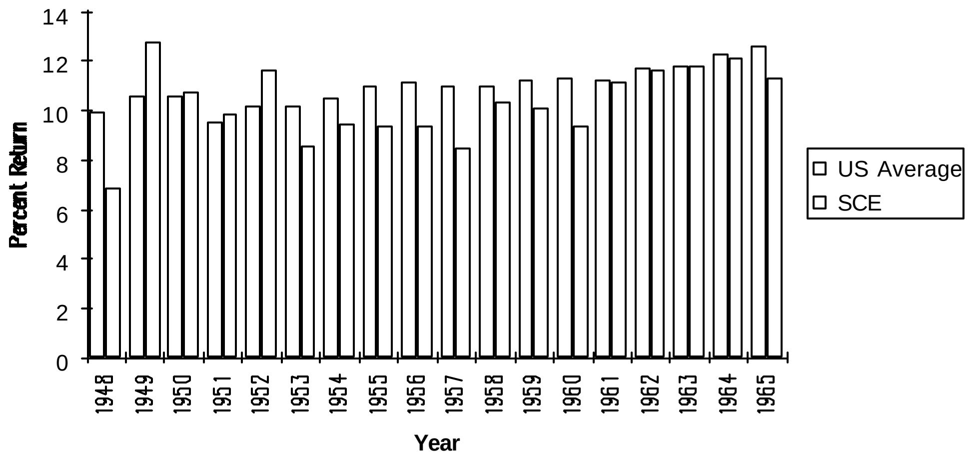
Figure III-12
California Electric IOU Average Rates



Source: California Statistical Abstract, 1970.

Figure III-13

Electric Utility Return on Common Equity



Source: Hyman (1992), page 115 and utility response to DSP data request, November, 1992. SCE used for comparison.

Regulatory Conditions

Not surprisingly, the steady financial conditions and strong financial performance of the electric utilities require a relatively simple cost-of-service regulatory regime. Steadily declining electric costs, resulting from the increasing size and improving efficiency of electric generating technologies, makes for infrequent rate proceedings. When rate cases are necessary, usually at the request of the utility, they are generally rate decreases. Between rate cases, utilities earn increasing and fairly predictable returns. There are no balancing accounts or revenue adjustment mechanisms; because of the infrequency of rate cases, utilities retain cost savings until the next rate case, and they retain additional revenue from increased sales. This prompts utilities to be efficient and market their product. Utilities bear significant risks but, due to stable economic conditions, rarely suffer.

The prevailing rate design philosophy also promotes consumption. Electric utility rates are based on embedded system costs, the costs of owning and operating the existing utility system. This is in keeping with legal requirements that rates be "just and reasonable" based on utility costs of service. Regulators allow "declining block" pricing by the utilities. Fixed costs, which are the costs of generation, transmission, and distribution facilities, are generally collected from the first "block" of consumption or demand/customer charges. The price for subsequent increments of consumption are lower and tend to follow actual variable utility costs, principally fuel, which are fairly stable and predictable.

CHAPTER IV

1966-1981: TROUBLED TIMES

By the late 1960s, despite the appearance of stability, conditions affecting the electric utility industry started to change. Inflation, interest rates, and fuel oil prices began to increase. In the 1970s, U.S. and California energy policy--particularly that related to electricity supply and distribution--underwent dramatic changes. These changes were in response to the new conditions confronting the economy in general, and the electric utility industry in particular. By 1980, the financial health and technical integrity of electric utilities, in California and across the country, was under siege.

This section explores the broad economic conditions confronting the U.S. and California and the effect they had on the electric utility industry during this turbulent period. This section also discusses the responses utility regulators pursued in light of the drastic changes affecting the industry. Our discussion centers on California, its utilities, and its regulators, but an examination of the economic conditions also requires a broader focus.

Economic Conditions

In stark contrast to the previous period, prevailing economic conditions from 1966 to 1981 are volatile and unpredictable. Interest and inflation rates are on the rise; fuel prices undergo dramatic increases with major repercussions for the U.S. and California. Compounding these difficulties, the growing recognition of the environmental consequences of electricity generation and the need to minimize them forces change on the industry and it regulators.

Inflation and Interest Rates on the Rise

Inflation emerges as one of the major problems facing the U.S. and California economies. By 1973, the Vietnam War and the military costs of U.S. involvement have exerted inflationary pressures on the U.S. economy; annual percentage changes in the Consumer Price Index begin their upward march in 1967 (Figure IV-1). In 1971, inflation exceeds five percent, an unthinkable level when viewed through the lens of previous decades, when general inflation ran at less than one or two percent. President Nixon institutes price and wage controls in an attempt to moderate inflation rates. By 1974, due to increases in the cost of fuel, inflation jumps to more than eleven percent; between 1974 and 1980, inflation is never lower than 4.5%, and reaches a high of 17.8% in 1980.

Figure IV-1

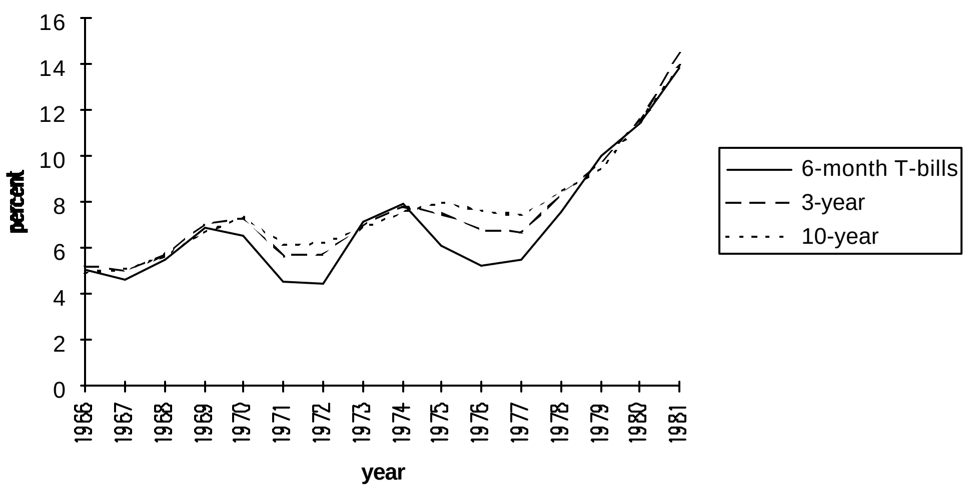
Percent Change in Consumer Price Index

Source: Hyman (1992), page 129.

As the country and California feel the pressure of high inflation, the costs of borrowing are also on the rise. Between 1966 and 1980, U.S. interest rates, reflected in rates on short and long-term Treasury Bills, increase from under six percent in 1965 to almost fourteen percent in 1980. (Figure IV-2) For a capital intensive industry such as the electric utility industry, which must borrow heavily to finance new facilities, high interest rates puts upward pressure on electricity costs and rates at a time when other pressures, such as increased oil prices, are already increasing consumer costs for electricity.

Figure IV-2

Interest Rates, 1966-1981



Source: Council of Economic Advisors, 1992.

Oil Prices Begin to Rise

Rapidly escalating crude oil prices also further inflation. The OPEC embargo in 1973-74 and the Iranian revolution in 1979 instigate oil price increases. While the potential for a disruption of foreign oil supplies has been a concern of U.S. foreign policy since at least the early-1950s, the U.S. has sufficient production capacity to meet domestic demands.[24] By the early 1970s, however, circumstances change. Increasing U.S. and world demand for oil outstrips U.S. ability to "back-up" imported oil in case of a supply disruption. U.S. production capacity hits its peak at 11 million barrels per day in 1973; it declines rapidly thereafter. The

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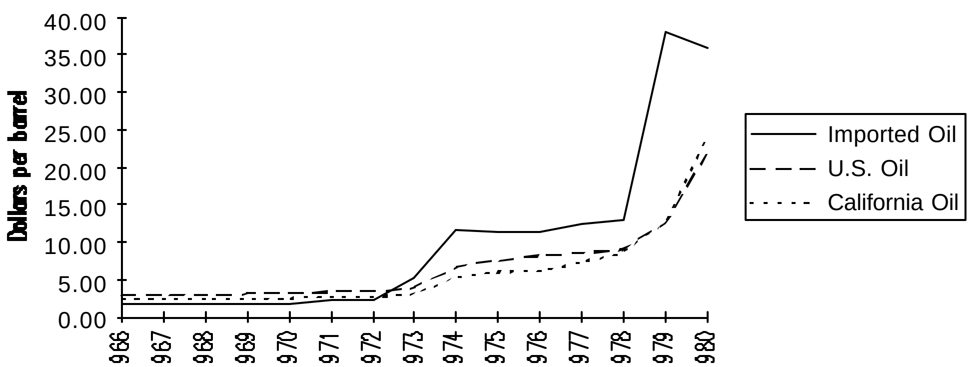
24 A good description of these events is contained in Part IV of Daniel Yergin's book, The Prize, New York: Simon & Schuster, 1991.

U.S. and developed countries can no longer count on U.S. supplies as backup in emergencies.

The OPEC embargo in 1973 leads to price increases for crude oil from $3 per barrel to almost $12 per barrel; in 1979, the disruption of Iranian oil exports caused by the revolution raises prices from around $13 to over $30 per barrel (Figure IV-3a); in Rotterdam, panic buying in the spot markets for oil push prices to $40-50 per barrel. Prices for natural gas increase from well under fifty cents per million BTUs to over two dollars by the end of this period (Figure IV-3b). In California and throughout the country there is widespread belief that escalating oil prices will continue; it is commonly assumed that, by the end of the century oil could be $100 per barrel. OPEC feeds this belief by developing a long-range strategic plan calling for annual price increases of 10-15%, which would culminate in a price of $60 per barrel by the mid-1980s.[25]

Figure IV-3a
Wellhead Crude Oil Prices, 1966-1980



Nominal dollars. Source: Imported oil prices from American Petroleum Institute, U.S. and California prices from Petroleum Data Book. Section VI, Table 8.

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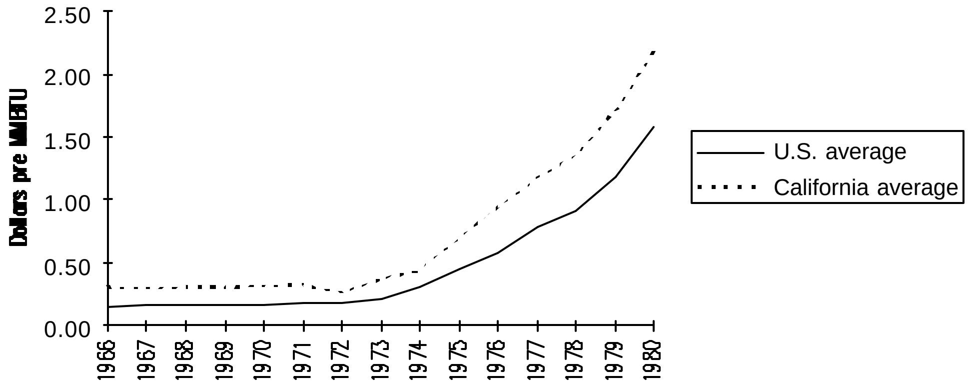
[25] Yergin, The Prize, page 705.

Figure IV-3b

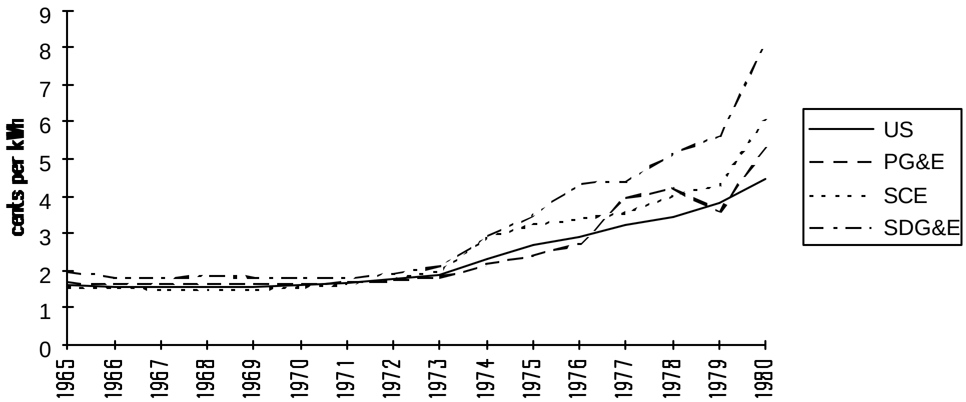
Wellhead Natural Gas Prices, 1966-1980



Nominal dollars. Source: Petroleum Data Book, Section VI, Table 9.

For electricity production, increases in the cost of fossil fuels, especially oil, are a special problem. In California, where electric utilities are heavily reliant on oil-fired electric generation, system average electricity prices increase from under two cents per kilowatt-hour to over five cents between 1965 and 1981. By 1980, all three utilities are above the national average with SDG&E's average rate reaching 8.1 cents per kWh in 1980 (Figure IV-4). Even PG&E, with significant hydroelectric and geothermal power, feels the pinch of the oil crisis as its average rate rises to 5.3 cents per kWh. As a result, some observers of the electric utility industry call for utilities to diversify electricity production sources away from imported fossil-fuels. Some government offices and utilities suggest turning to indigenous resources, such as coal and nuclear; others promote less traditional sources, such as conservation and renewable power.

Figure IV-4
Average Electricity Rates



Nominal dollars. Source: U.S. from Hyman (1992), page 129, utility rates from utility responses to DSP data request, November, 1992.

The "Greening" of Electric Utilities

In addition to increasing fossil fuel prices, the 1970s see the emergence of an environmental movement. The first Earth Day in 1970 demonstrates that environmental quality is a broad-based public issue. Environmentalists press government and industry to give greater consideration to minimizing the environmental effects of their actions. This is codified in 1970 by the National Environmental Policy Act (NEPA); in California, slightly stronger legislation is enacted in the California Environmental Quality Act of 1970 (CEQA). These laws require comprehensive analysis of any environmental impacts of projects requiring government approvals such as permits or certificates. CEQA goes so far as to state that:

> "It is the intent of the Legislature that all agencies of the state government which regulate activities of private individuals, corporations, and public agencies which are found to affect the quality of the environment, shall regulate such activities so that major consideration is given to preventing environmental damage, while providing a decent home and satisfying living environment for

every Californian."[26]

In decisions interpreting CEQA and its requirements, courts find that state agencies cannot approve projects with significant environmental effects unless they are mitigated or unless overriding considerations exist.

CEQA, NEPA, and other environmental legislation such as the federal and state Clean Air Acts, Clean Water Acts, and Endangered Species Acts increase the costs and time required for project approval and construction. For electric utility projects in California, a CEQA environmental impact report usually requires at least 9 to 12 months and costs several million dollars; it is not uncommon for delays to extend the amount of time required.[27] The federal and state Endangered Species Act can require additional habitat studies to confirm the existence of threatened or endangered species. If endangered species exist on or close to the project site, a project can be canceled or significantly modified.[28]

Environmental concerns thus begin to add to the cost of electricity. The Four Corners coal plant in Arizona is completed by Edison in 1969 at a cost of $102 per kilowatt and at a time when there are minimal emission clean-up requirements. By 1985, new environmental

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[26] California Public Resources Code, Section 21000(g).

[27] CEQA requires an EIR to be completed within one year of agency acceptance of the project application as complete. An extension of up to ninety days is available with the consent of both the Lead Agency and applicant. Suspensions of the time period are also available due to unreasonable delays by the applicant. CEQA Guidelines, Sections 15108 and 15109.

[28] The California Endangered Species Act (California Fish and Game Code, Chapter 1.5, Sections 2060-98) requires the state Department of Fish and Game to submit a biological opinion on habitat impacts of a CEQA project to the Lead Agency. Lead Agencies are prohibited from approving projects where the best scientific evidence shows that the project will result in species extinction.

rules, applied retroactively to already completed plants, cause Edison to install emission controls at Four Corners that equal the original cost of the plant.[29]

Industry Response

In the face of dramatically increasing costs, throughout this period and especially after the oil embargo, utilities find themselves challenged by the need to minimize electricity costs and maintain system reliability. Utilities, many of which are in the midst of massive construction projects, can no longer rely on increasing economies of scale to offset upward pressures on rates. Largely due to rising fuel costs, utilities' marginal costs are higher than average costs for the first time.

The response by the utility industry is varied. Some utilities continue planning as if nothing has happened. Their plans to expand do not change as they continue to project increasing customer demands at historical levels. Other utilities are more cautious but no more realistic; they continue to pursue large generation, in the pursuit of economies of scale and in the face of the environmental movement. The result will be financial difficulties for many of them, including California's utilities.

Meeting Future Demand

Nationwide, concerns over electric reliability grow in the wake of the 1965 Northeast blackout; the blackout vividly demonstrates the economic and political importance of reliable electric supplies. California utilities continue to expect high customer demand and develop expansive construction plans to meet demand. Southern California Edison's 1970 resource plan forecasts demand growth at eight percent and a need for an additional 12,000 megawatts of capacity in the 1980s.[30] A RAND report predicts that, if utility projections hold true, by

29 Risk Return and Ratemaking, op. cit.: Constant dollars.
30 Planning for Uncertainty, System Planning and Research, Southern California Edison,

the year 2000 California utilities will have over 31,000 MW of nuclear and almost 18,000 MW of coal.[31]

In response to high utility growth projections and utility worries about the complexity of licensing power plants in multiple jurisdictions, the California legislature creates the California Energy and Resource Development Commission (California Energy Commission, or CEC) in 1975. The CEC is to be a "one-stop" power plant licensing agency, with jurisdiction over the licensing of thermal power plants larger than 50 MW. To license power plants, the CEC is empowered to forecast future consumer demand, which will provide an objective assessment of the future need for the power plant. The licensing process includes an assessment of the need for the proposed facility, alternatives to the facility, and its environmental impacts, consistent with the requirements of CEQA. The CEC review results in significantly reduced utility plans for new generating facilities and an increasing emphasis on techniques for using electricity more efficiently.[32]

Utilities Go Nuclear[33]

Prior to 1974, U.S. and California utilities are concerned about meeting the rising electricity demands of consumers; moderate oil price increases before the OPEC embargo and increasing air quality restrictions spur utilities to investigate options for reducing their dependence on crude oil. Utilities are exploring old options, such as coal, and new options,

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Dec. 1986, p. 5.

31 Ahern, W., Doctor, R., et al, Energy Alternatives for California: Paths to the Future, 1975; Santa Monica: Rand Corporation, R-1793/1-CSA/RF, pp. 142, 144.

32 The CEC's first and second Biennial Reports describe this history.

33 Much of the background for this section is from Energy Future, Stobaugh, R., and Yergin, D., New York: Random House, Chapter Five.

such as nuclear power. In 1970, Southern California Edison envisions a total of 5 nuclear units at San Onofre, 2 nuclear units at Point Conception, and a coal plant at Fry Mountain near Victorville[34]. PG&E planners anticipate relying mainly on nuclear power in the "Super System," designed to meet PG&E's needs through 1980.[35] SDG&E is planning on constructing nuclear units at the Sundesert site.

Ultimately, interest in additional coal-fired facilities wanes as air emissions standards become more stringent under the recently enacted Clean Air Act. By the late 1960s and early 1970s nuclear power is seen as the developed world's best defense in the face of potential future oil supply disruptions; governments encourage nuclear power as an alternative to oil.[36] In November of 1973, with lines at gasoline stations and public frustration growing, President Nixon unveils Project Independence. Its goal is an independent U.S. energy system by the end of the 1970s and the use of nuclear power for thirty to forty percent of U.S. electricity requirements.[37] In 1975, President Ford presents his own Project Independence, calling for 200 nuclear power plants in the U.S., as well as the increased use of coal for electricity production.[38]

By 1979, however, the U.S. nuclear card has been played out. The accident at the

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[34] Planning for Uncertainty, Southern California Edison, p. 5.

[35] Roberts, Marc J., and Bluhm, Jeremy S., The Choices of Power, Cambridge: Harvard University Press, 1981, p. 128.

[36] PG&E expresses its interest in nuclear power as early as 1957, contributing to the experimental reactor at Vallecitos; it then constructs one of the first private nuclear power plants in the US, the 63 MW Humboldt Bay plant. By 1968, PG&E, Edison and SDG&E are all involved in nuclear power plants construction and operation.

[37] Yergin, The Prize, op. cit., p. 617.

[38] Ibid., p. 660.

Three Mile Island nuclear generating facility is the final straw on the back of the U.S. nuclear industry. On March 28, 1979, a combination of mechanical and human errors lead to massive damage to the radioactive core of one of the multiple nuclear units at Three Mile Island in Pennsylvania. While this incident leads to the cancellation of a number of projects on the drawing boards, the industry is already in decline even as the first release of radioactive steam takes place in Harrisburg. Less than half a dozen nuclear units are ordered between 1975 and 1979; another twenty previously planned nuclear plant orders are canceled.[39] Delays occur for utilities with nuclear units under construction. PG&E's Diablo Canyon experiences significant delays at least three times during its construction.[40]

Nuclear plant construction delays are not limited to California. The nuclear power experience is replete with examples of extensive construction delays and cancellations in other states--Seabrook, Shoreham, Palo Verde, and the Washington Public Power Supply System. Some nuclear facilities beginning operation in 1972 take only four years from start to finish. In contrast, for nuclear power pants beginning operation after 1982, average construction time is twelve years.[41] Because of their high capital and construction costs, nuclear power plant delays lead to increases in utility borrowing to finance the construction.[42]

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39 Stobaugh and Yergin, Energy Future, Chapter 5, pp. 108-109.

40 Resource, PG&E, page 321. In 1973, in response to seismic concerns regarding the Hosgri fault, the plant is redesigned and substantially modified to meet federal standards; in 1979, the Three Mile Island incident leads to extensive safety modifications at all U.S. nuclear plants under construction; and in 1981 a design review reveals that incorrect assumptions had been used during the plant's redesign, requiring further modifications.

41 Kaufman, et al, Gold at the End of the Rainbow, page 28.

42 In California, as in most other jurisdictions, utilities do not receive compensation in rates for facility construction costs until the plant begins operating (subject to a reasonableness review). However, utilities receive an allowance for construction costs that are financed during construction (Allowance for Funds Used During Construction, or AFUDC). AFUDC is included in net income for accounting purposes but is not actually reflected in cashflow

CHAPTER IV

While many of the early nuclear plant delays and cancellations are the result of utility, regulator, and public safety concerns, later delays or cancellations are due to questions regarding the fundamental economics of nuclear power. Nuclear opponents question the excessive costs of nuclear power, believing that the safety requirements of harnessing nuclear power extract excessive tolls. Others point to the challenges of finding safe long-term storage for spent nuclear fuel; nuclear fuel rods, once used up, continue to remain radioactive for thousands of years. Spent fuel assemblies are generally maintained on-site as the nation debates the location and construction of long-term storage facilities. New safety regulations are often applied retroactively and many facilities face continuing capital requirements that, over the life of the projects, may equal the initial project costs.[43] In 1976, California bans the construction of new nuclear units until permanent waste storage solutions are devised.[44]

By 1981, despite continuing concern over fossil fuel dependence in the U.S. and California, no new nuclear power plants are under consideration. The combination of safety and environmental factors, and expensive and complicated plant construction, reduces the

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from ratepayers until plant operation. AFUDC is not real income until regulators allow it in rates, diminishing its value to financial markets.

43 In a recent decision, the CPUC authorized SCE and SDG&E to begin writing down their undepreciated capital costs for SONGS 1 over four years as the plant, taking into account the need for future capital requirements, is no longer cost-effective (Decision 92-08-036).

44 Public Resource Code, Section 25524.2.

attractiveness of the nuclear alternative. Hopes for nuclear power lie in new standards and technologies which can lower plant costs and resolve safety and waste storage concerns.

Developing Natural Gas Resources[45]

Gas, used primarily for street lamps, was available in California in the mid-1850s. Initially, this gas was synthetic; utilities made this "town gas" locally from coal. Natural gas was generally a product associated with oil production; because of transportation limitations, natural gas was either used in oil production areas or, more commonly, burned off or "flared". With the development of high-volume pipelines, producing areas were able to market natural gas to consuming regions.

By the mid-1970s, natural gas is considered a premium fossil fuel for electricity production. Because it is mainly an indigenous resource, it is perceived as secure from OPEC-type embargoes or political pressures. Natural gas is a cleaner fuel, with lower emissions than coal or oil, and the transportation system for gas is more secure and poses few long term environmental problems. With minimal investments, most technologies that use oil can use natural gas. Thus, natural gas becomes a desirable commodity.

Despite its attractiveness, natural gas is in short supply. The winters of 1976-77 and 1977-78 see shortages of natural gas in some consuming areas. Supply curtailments cause inconvenience and millions of dollars of lost business. The regulatory structure which has developed, consisting of federal regulation of the interstate market and state regulation of the intrastate market, as well as differing regulatory approaches by state and federal regulators, leads to higher intrastate prices. In response, producers dedicate more supplies to their

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45 Historical background for this section was provided from Energy Future, by Stobaugh and Yergin, Chapter 3 and various CPUC decisions.

intrastate market, leading to tight supplies for interstate transportation companies and curtailments for interstate customers.

In the face of the curtailments, there is some concern that the U.S. is running out of natural gas. National gas production peaks in 1973 and falls 12 percent by 1978; proven reserves peak in 1967 and fall 25 percent by 1978, to a volume equal to only ten years of consumption. Although many reputable sources believe that gas exists in undiscovered locations, the statistics seem to leave some doubts. In the belief that regulation has led to the short supply of natural gas, Congress passes two bills as part of the Carter energy plan in 1978. The first, the Power Plant and Industrial Fuel Use Act, prohibits the use of oil or natural gas in new electric power plants or natural gas in existing plants after 1990.[46] The Natural Gas Policy Act deregulates the price of newly discovered natural gas and eliminates the distinctions between interstate and intrastate natural gas. Although the NGPA has a simple goal, it is a complex piece of legislation due to the difficulty of managing the transition from wellhead price controls to deregulation. Price deregulation, Congress hopes, will provide drilling incentives which will increase U.S. reserves of this valuable fuel.

Utility Financial Performance Suffers

The economic pressures of this period take their toll on electric utilities and their ratepayers. Nationwide, the price of electricity increases dramatically. Between 1965 and 1980, the average price of electricity almost triples (See Figure IV-4). Between 1948 and 1973, energy (electric and gas) rates increase by $6 billion; between 1973 and 1977, rates increase by $48 billion.[47] Changes in fuel prices drive most of these price increases. Of

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[46] These provisions are ultimately repealed.

[47] Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1977, page vii, Subcommittees on Intergovernmental Relations and Energy, 95th Congress, 2nd session. (Washington, D.C., US Government Printing Office, 1978).

$13.4 billion in rate increases in 1977, 80%, or $11 billion, are due to fuel increases.[48] Similar pressure is being felt in California. Between 1979 and 1980, Southern California Edison fuel and purchased power costs increase by one billion dollars to $2.4 billion. Fuel costs and purchased power costs represent 62% of Edison expenses in 1980, as opposed to 17% in 1979; in fact, the 1980 fuel bill is only $200 million less than Edison's total revenues from the prior year.[49]

Utility attempts to diversify away from expensive fossil fuels do not produce the intended results. Delays in nuclear power plant construction, and the escalating costs of that construction continue to exert pressure on utility earnings. Capital spending in 1980, largely for the construction of new generation, is seven times its 1965 level. (Figure IV-5). The capital for this construction comes increasingly from external sources; while debt represents only 38% of capital spending in the mid-1960s, it reaches over 75% by the end of this period. Borrowing is increasingly costly, with interest rates on new debt rising from 4.61% in 1965 to 13.46 % in 1980 (Figure IV-6). AFUDC, the paper earnings reflecting the financing costs for this borrowed capital, is increasing as a percentage of utility earnings (Figure IV-7). Utilities with high AFUDC percentages are increasingly cited as having "poor quality" earnings (since AFUDC income is not real income until and unless it is allowed to be recovered in rates by regulators).[50]

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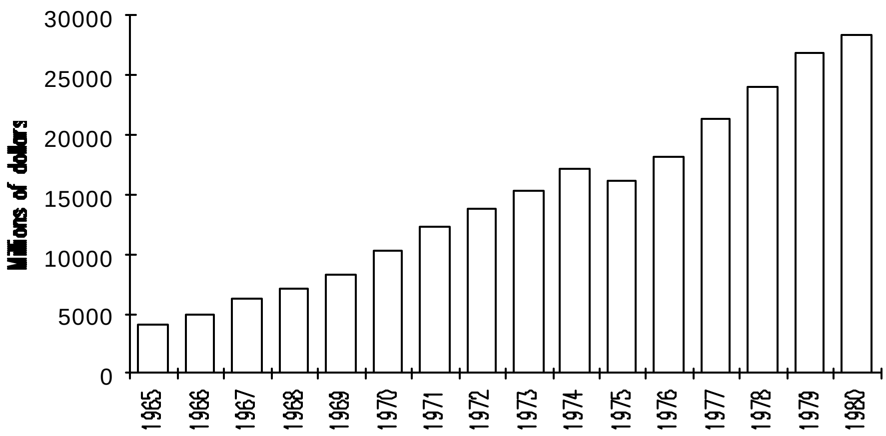
48 Ibid.

49 Remarks of Howard Allen, President of Southern California Edison, in Energy Utilities: The Next 10 Years, page 66.

50 Gold at the End of the Rainbow: a Perspective on the Future of the Electric Utility Industry, Kaufman, et al., 1984, Congressional Research Service, #84-236 S, page 51.

Figure IV-5

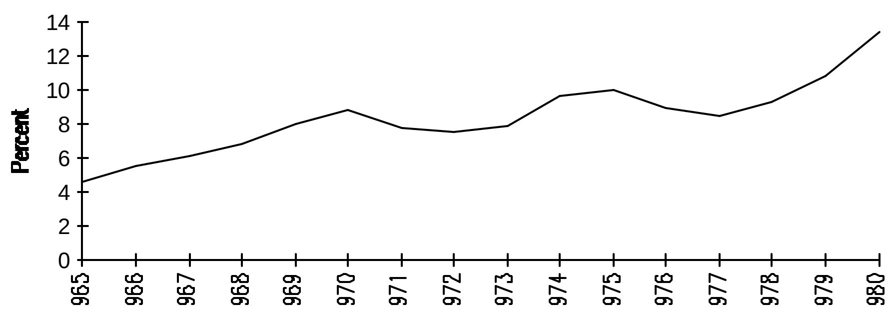
US Electric Utility Capital Spending



Source: Hyman, page 126.

Figure IV-6

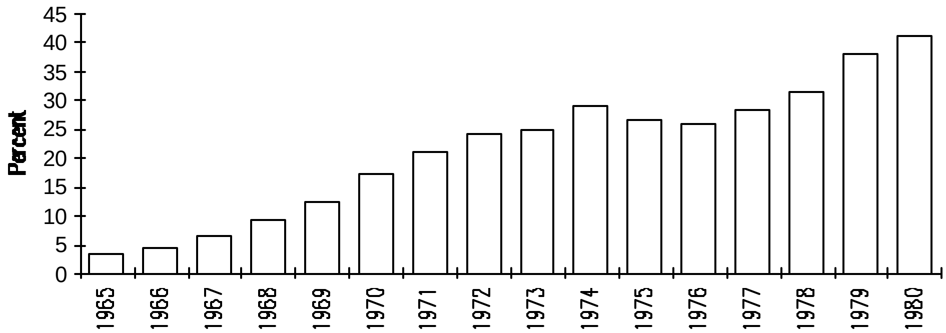
Rates on Newly-Issued Electric Utility Bonds



Source: Hyman, page 126.

Figure IV-7

AFUDC Percentage of Net Earnings

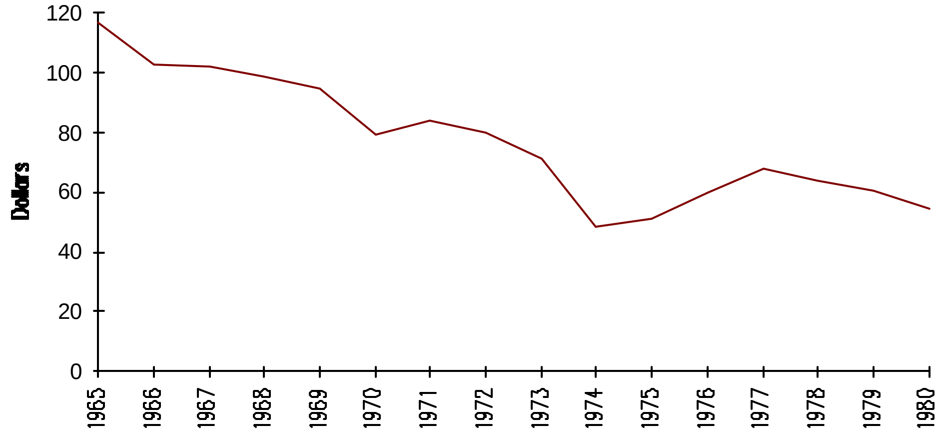


Source: Hyman (1992), page 131.

These trends lead to financial difficulties for utilities. The Moody's average stock price for electric utilities declines by over 50%, from over $117 per share in 1965 to just under $55 in 1980 (Figure IV-8). Market-to-book ratios, a reflection of investor confidence in a corporation, decline steadily during this period, to a low of 0.65 in 1980 (Figure IV-9). In California, electric utility returns are often below the industry average, especially between 1970 and 1975 (Figure IV-10a and IV-10b). In sum, utilities and their investors are no longer the investment of choice for those seeking steady and secure dividends.

Figure IV-8

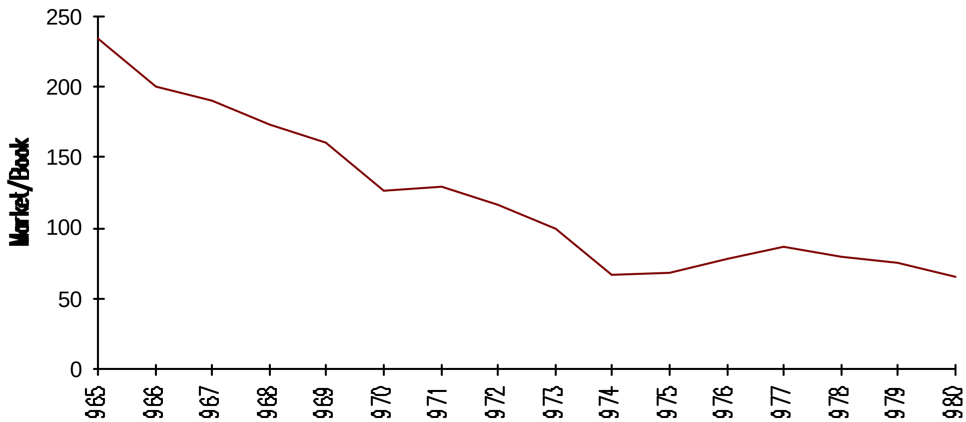
Moody's Average Stock Price



Source: Hyman (1992), page 131.

Figure IV-9

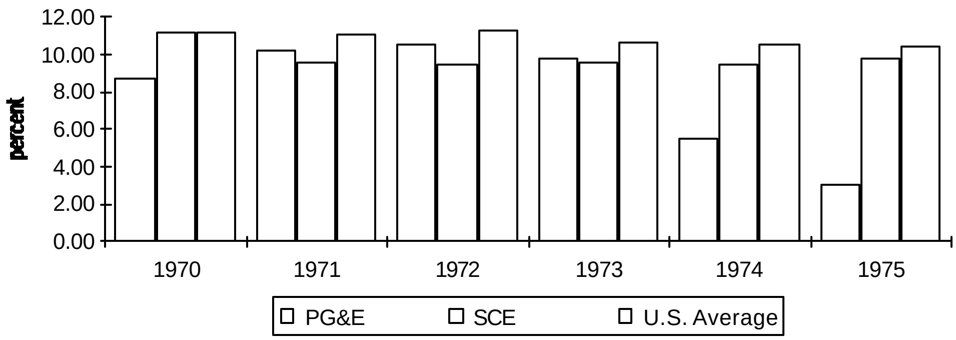
Average U.S. Market to Book Ratios



Source: Hyman (1992), page 131.

Figure IV-10a

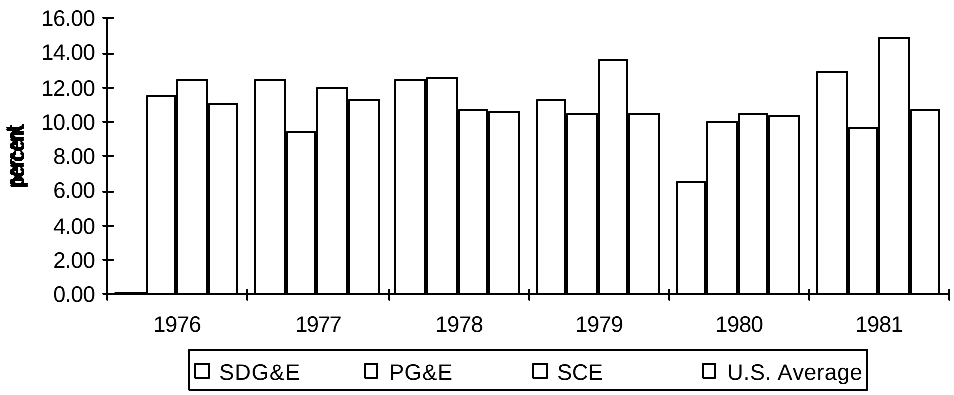
Utility Return on Equity, 1970-1975



Source: U.S. Average from Moody's Electric Utility Average, Hyman (1992), page 131; California utilities from response to DSP data request, November, 1992 (SDG&E data unavailable for this period).

Figure IV-10b

Utility Return on Equity, 1976-1981



Source: U.S. Average from Moody's Electric Utility Average, Hyman (1992), page 131; California utilities from response to DSP data request, November, 1992 (SDG&E data unavailable for 1976).

Regulatory Response

Regulators respond to the general volatility of this period with programs to maintain utility reliability and financial stability. Regulators are concerned that investor-owned electric utilities might not have the financial resources necessary to provide safe and reliable service. The increasing costs of fuel, inflationary pressures on non-fuel costs, increasing costs of and delays in the construction of power plants, and declines in the growth of electricity demand all, in the absence of regulatory action, undermine utility financial health.

At the same time, consumers express more interest in government, in general, and the workings of utility commissions, in particular. Ralph Nader's chronicle of the failings of the automobile industry in protecting consumers and Rachel Carson's description of the environmental dangers of pesticides all breed a distrust of industry and business.[51] As utility rate increase requests come to be a common occurrence in the seventies, organizations form to represent consumer interests in utility rate proceedings, increasing the strength of public input and range of pressures faced by regulators.

The Commission works to balance its interest in a safe and reliable electric system with its need to protect customers from unreasonable electricity costs, certainly not a new Commission requirement but a goal which is made more complex in the current environment. The Commission pursues a strategy of reducing the need for new plant construction through demand and supply-side measures and the use of balancing accounts to ensure utilities recover costs in a timely manner.

Reducing Demand Growth

One of the nation's major efforts during this period is to promote the development of more efficient energy use; many observers believe reducing energy demand will help achieve U.S. independence from OPEC. After the oil embargo, President Nixon initiates voluntary conservation efforts by asking consumers to turn thermostats down to 68 degrees and to reduce non-critical energy uses. Congress extends daylight savings time throughout the fall and winter of 1973-74 as an energy-saving measure. Utilities also respond by offering

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[51] Nader, Ralph, Unsafe at Any Speed: The Designed in Dangersof the American Automobile, New York: Grossman, 1965; Carson, Rachel, Silent Spring, Boston: Houghton, Mifflin, 1962.

programs to customers to minimize electricity bills.[52] The federal government also enacts several laws promoting energy conservation. For example, the Energy Conservation and Production Act of 1976 provides weatherization assistance for low-income customers, establishes energy conservation standards for new buildings, and conservation demonstration plans. The National Energy Conservation Policy Act of 1978 establishes the Residential Conservation Service, which provides home energy audits through utilities. California utilities take a national leadership position in developing programs such as the Zero Interest Program for energy conservation improvements and the Solar Rebate Program for home solar hot water heaters.

By the late-1970s, California is a leader in energy conservation. In a decision in September 1975, the Commission first articulates its position on conservation:

> "We regard conservation [as] the most important task facing utilities today. Continued growth of energy consumption at the rates we have known in the past would mean even higher rates for customers, multi-billion dollar capital requirements for utilities, and unchecked proliferation of power plants. Energy growth of these proportions is simply not sustainable. Reducing energy growth in an orderly, intelligent manner is the only long-term solution to the energy crisis[53]

The decision delineates the means by which the Commission will promote conservation efforts by utilities. In future rate and Certificate of Public Convenience and Necessity (CPCN) proceedings, the Commission will closely review utility conservation programs, making "an informed objective evaluation" of the utility's efforts. Programs are not to be limited to advertising; utilities are to take an active role in promoting conservation by

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[52] Delehunt, Ann and Rickets, Grant, "PG&E: Meeting California's Energy Needs Through the Year 2000," unpublished draft case study for Harvard University, page 3.

[53] 78 CPUC, page 746 (Decision 84902, September 16, 1975).

customers, including "subsidizing" capital intensive conservation applications, research and development, and appliance service and repair by utility representatives. By 1981, California investor-owned utilities are spending almost $50 million a year (1985 dollars) on programs and measures for conserving electricity.[54]

The Importance of Rate Design

In addition to conservation investments, the Commission begins to explore a simple policy concept which, without requiring any utility investment, can easily produce more efficient electricity consumption - marginal cost pricing.

Electric utility rate design is the method by which utility revenue requirements are translated into customer rates and charges. The revenue requirement is first allocated to customer classes based on the costs of serving those classes ("revenue allocation"). Then specific rates are calculated to recover the required revenue from each class ("rate design").

Until the late 1970s, embedded costs are used to establish utility rates. Because utilities still have some inexpensive resources, mainly depreciated hydroelectric plants, embedded costs are less than marginal costs. Economic theory suggests that prices based on embedded costs give the wrong price signals to customers. As a result, customers think the cost of electricity is less than it really is and over-consume electricity. Prices based on marginal costs give customers the proper price signal regarding the value of electricity, especially during the current period of high oil prices. By 1979, the Commission uses marginal costs in allocating utility revenue requirements to customer classes and in establishing rates. Rates are not set equal to marginal cost; however, because marginal costs alone would not necessarily allow utilities to recover their revenue requirement. Regardless, giving consideration to

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[54] Calwell, C.V. and Cavanagh, R.C. The Decline of Conservation at California Utilities: Causes, Costs and Remedies, San Francisco: Natural Resources Defense Council, July, 1989, page 13.

marginal costs vastly improves the pricing signal.

An extension of marginal cost pricing is time-differentiated pricing. Customer demands, and the utility resources employed to meet those demands, vary throughout the day, hitting peak levels late in the day. Thus, the marginal cost of electricity during the peak period, when expensive plants are turned on to meet demands, is much higher than during the rest of the day. Because utilities must build new plants if peak demand increases, reducing peak demand can defer the need for new utility plants. By charging more for electricity during those periods, reflecting the higher cost of marginal production, utilities and regulators believe that customer demand, and the need for additional resources, will decline.

Peak-load pricing is not without some controversy. It requires distinguishing peak periods from off-peak periods. Peak-load pricing requires more expensive electric meters that can differentiate electric use by time period. Customers using power on-peak are generally opposed because it results in increased costs.

Regardless, in 1976 the Commission orders the phased implementation of peak load pricing (also known as Time-of-Use or TOU pricing) for large electric consumers (greater than 500 KW demand). The Commission focuses its initial efforts on large industrial customers in order to obtain the largest potential load reduction. Eventually, TOU pricing, on a voluntary or mandatory basis, is available to most industrial customers.

Exploring Cogeneration and Renewables

As to environmental pressure and the need to diversify away from fossil-fueled plants grow, national and state decision-makers increasingly respond to advocates of cogeneration and renewable energy. These advocates point to the tremendous potential that exists for cogeneration and renewable energy to make electricity production more efficient and environmentally sound, and to reduce reliance on imported fossil fuels.

Cogeneration uses fossil fuels to produce both thermal and electrical energy, by capturing heat that would normally be wasted and using it to produce electricity. Using steam in this way results in a more efficient use of fossil fuels. Cogeneration is not a new technology; before the advent of the vertically integrated utilities, many industrial facilities produced their own steam and electricity. In 1950, 15% of the nation's electricity was produced by industry. By the end of the 1950s, utilities had taken advantage of economies of scale in electric generation and electricity prices declined, thus diminishing the economic attractiveness of cogeneration. By 1973, less than 5% of the nation's supplies are provided by industry.[55]

Renewable energy refers to non-depletable, non-fossil sources of energy, such as wind, geothermal, hydroelectric, solar, or biomass. Using renewable resources to generate electricity reduces the need for conventional fossil or nuclear technologies. Many renewable energy technologies have been in use for decades but, when compared to the costs of electricity from oil or coal, are not cost-effective at historical oil and gas prices.

There are many forces working against the use of these alternative sources. Rate design for industrial customers, especially declining block rates, reduces the incentive for cogeneration by industrial firms. Further, the threat of regulation exists for firms that cogenerate and sell electricity to other utility customers.[56] Utilities, generally concerned with the reliability of their systems, are reluctant to purchase power from unproven and uncertain supply resources. More important, utilities are not convinced that cogeneration can result without loss of existing customers. Renewables, in addition to the reliability questions, are not perceived to be cost-effective when compared to fossil-fuel sources, even at current

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55 Stobaugh and Yergin, Energy Future, page 159.

56 Under interpretations of federal and California law, such sales make the selling entities public utilities, requiring rate and service regulation by the CPUC.

prices.[57]

Despite the pressure from advocates of alternative energy, utilities and regulators are unwilling to promote its development. It takes federal legislation, the Public Utility Regulatory Policies Act of 1978 (PURPA), to spur utilities and regulators to act. PURPA, part of President Carter's energy initiative, asks utilities to review various rate design and load management programs. Its most far-reaching sections deal with the development of Qualifying Facilities (QFs): non-utility producers selling electricity to utilities. PURPA establishes two categories of QFs, cogenerators and renewable small power producers. The Act requires FERC to establish regulations for utility purchases from QFs; by 1980 FERC establishes rules for regulatory bodies like the Commission to use for implementing PURPA:

? Utilities are required to interconnect with QFs;

? Rates for purchases from QFs are not to exceed utility "avoided costs", the cost a utility would pay to generate or purchase the power in the absence of the QF;

? QFs are to be supplied with "stand-by" power, service to operate facilities if the QF is unable to operate; and,

? QFs are exempt from the electric utility regulatory requirements of the Federal Power Act.

By allowing prices to equal full avoided cost, FERC establishes the concept of "ratepayer indifference": ratepayers should be indifferent to the use of QF power or utility generation because, from their perspective, both options have the same cost. FERC cites other benefits that QFs provide, like size and resource diversification, independence from

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[57] California utilities, especially PG&E, were to some extent an exception. PG&E had several geothermal facilities in operation and on the drawing boards in the mid-1970s. PG&E also owned and operated large amounts of hydroelectric projects in the state; SCE, although at a much smaller scale, also used hydroelectric sources.

foreign oil, and production efficiencies, as justification for full avoided cost. By 1980, PURPA implementation is in the realm of the state ratemaking bodies such as the Commission.

The Commission is aggressive in developing California's QF program. Commission efforts, in fact, precede FERC's regulations implementing PURPA. California enacts legislation in 1976 promoting the development of non-utility sources of electricity.[58] By 1979, for a variety of reasons California's investor-owned utilities' construction plans are substantially off track. By the end of this period, major capacity additions (SONGS 2 & 3, Palo Verde, Diablo Canyon, Helms) are delayed, with no assurance, especially for the nuclear power plants, they will ever begin operating. The delays lead to serious financial problems as the percentage of utility earnings from AFUDC escalates to high levels. (See Figure IV-7) Concern begins to be expressed that utilities might not have the capacity to maintain system reliability; for PG&E, for example, reserve margins fall below 10% several times during the late 1970s, reaching 6% in 1981.[59] In 1980, the Legislature, fearful of capacity shortages, directs the Commission and the CEC to prepare a joint study on electric system reliability.

Initial Commission attempts to spur the development of alternative energy sources rely on the informal authority of the Commission; the thrust is to encourage utilities, on their own initiatives, to pursue renewables and cogeneration. This tactic fails to sufficiently stimulate utility interest and, in 1978, the Commission penalizes one utility, PG&E, for failing to develop enough cogeneration projects.[60] The Commission issues a decision in 1979 delineating its

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[58] Statutes of 1976, Chapter 915.

[59] Delehunt, op. cit., page 5.

[60] Ahern, William R. "Implementing Avoided Cost Pricing for Alternative Electricity Generators in California" in Trebing, A.M. and Mann P.C., New Regulatory and Management Strategies in a Changing Market Environment, East Lansing: Michigan State University, 1987, page 405.

reasons for promoting QFs:

> "a) cogeneration uses fuels more efficiently than when industrial processes and electric generation are performed separately; b) alternative generating sources diversify the utility's resource plan and minimize dependence on any single source of generation; c) generation from biomass, wood waste, and refuse offers independence from foreign fuel sources...; d) the development of many small power plants contributes to system reliability. The possibility of many small plants failing simultaneously is less than the probability of one large central station plant suffering a forced outage; e) the lead time required for construction of a small facility is estimated to be several years less than for large central station power plants...; f) the utility... will not have to raise the capital to construct the facility, and the facility will not be included in the utility's rate base."[61]

In 1980, the Commission issues Order Instituting Rulemaking 2 (OIR 2), to develop rules for establishing a program for cogeneration and renewable non-utility generators, in accordance with PURPA requirements.[62] This rulemaking culminates in Decision 82-01-103 (January 21, 1982), which establishes the general rules for the Commission's QF program, including avoided cost pricing calculation, standard offer contracts, and contract availability.

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61 3 CPUC 2d, 11-12 (Decision 91109, December 19, 1979).

62 OIR 2 was one of the Commission's first rulemaking proceedings, under procedures adopted by the Commission in June, 1980.

CHAPTER IV

Insulating Utilities from Risks

Across the country, the financial health of utilities is continually in question. Regulators, who historically had been asked to review utility costs only at infrequent intervals, are now bombarded with frequent requests for rate increases. It is not uncommon for state ratemaking bodies to have several different requests from a utility for rate increases at the same time, as utilities try to keep up with the rapid pace of cost increases. At the same time, regulators are under pressure from consumers to keep rate increases to a minimum. Intervenors in rate proceedings, representing small and large consumers, contest utility assertions regarding cost increases and demand more efficient utility operations.[63] Ratemaking bodies such as the Commission are under tremendous pressure to balance the financial health of utilities **and** protect consumers from unreasonable cost increases.

In California, the Commission is troubled by the financial health of the utilities. One utility, SDG&E, is on the verge of bankruptcy;[64] the other two utilities, in the midst of heavy construction programs, have poor cash flow. The Commission responds to the utilities' financial picture by developing regulatory policies that will allow more rapid cost recovery.

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63 "Grassroots" advocates become much more common during this period. Several publications (e.g., How to Challenge Your Local Electric Utility: A Citizen's Guide to the Power Industry, by Richard E. Morgan and Sandra Jerabeck) are published to guide citizens in contesting utility rate requests.

64 In a concurring opinion for a CPUC decision authorizing a large general rate increase for SDG&E, including some costs for the canceled Sundesert Nuclear Plant, CPUC President John Bryson notes SDG&E's precarious financial position as justification for the large rate increase. 1 CPUC 2d, p. 727 (Decision 90405, June 5, 1979).

CHAPTER IV

ECAC

One of the Commission's first major regulatory reforms is the creation of fuel cost adjustment mechanisms for natural gas and electricity. The basic justification, as stated in a 1976 Commission decision, is that a system for quickly adjusting revenues is necessary because:

> "...(1) in an inflationary period, with rapid changes in the cost of fuel, an expedited method is required to permit a utility to recover these costs so that its ability to function is not impaired; (2) ... an expedited proceeding... will lessen the frequency of general rate cases; and (3) ...it enhances a utility's position in the financial community."[65]

The fuel cost adjustment (FCA) mechanism goes through modifications over time. Originally, the FCA mechanism applies only to changes in fossil fuel expenses. In 1975, the Energy Cost Adjustment Clause (ECAC) is created for all fuel expenses, including power purchases.[66] This removes some of the uncertainty that exists with respect to hydro conditions, a potentially large "swing" factor as utilities purchase large amounts of economy energy from the Pacific Northwest. Later, in response to criticisms that ECAC offers little incentive to utilities to be efficient, the Annual Energy Rate (AER) is created. The AER is a percentage of utility fuel costs that is not in the ECAC billing factor, but is collected in base rates. With the AER, the Commission hopes to create an incentive for utilities to minimize

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65 73 CPUC 186. This decision authorized Edison to use an FCA because of the rapidly changing fuel markets that began in the early 1970s, even before the oil embargo. FCA mechanisms were ultimately adopted for all California electric utilities.

66 79 CPUC 760-779.

fuel costs by allowing them to retain AER over-collections and be responsible for AER under-collections.[67]

Rate Case Plan and Attrition

Inflation continues to rise, reaching a peak of 17.8% in 1980. Under traditional cost-of-service regulation, utilities bear the risks of changes in between rate proceedings. If costs increase above levels estimated at the time of the rate case, utility shareholders bear the risks until rates are changed in the next rate case. During the 1970s, utilities cannot bear the large financial costs incurred in between rate proceedings. Utilities file for rate increases any time costs change significantly; as a result utilities often have multiple rate proceedings under way. The number and complexity of rate proceedings begins to tax the capabilities of the Commission and its staff. Rate proceedings take longer to complete, exacerbating utility financial problems.

The Commission responds by adopting a rate case plan for electric utility base rates in 1977. The Commission originally establishes a step-by-step process for conducting utility rate requests in a timely fashion. The Commission also establishes schedules for utility rate application filings and the issuance of Commission decisions. In 1979 the plan is modified to limit rate change requests to every two years; the rate case will estimate expenses for the test year and establish rates accordingly. For intervening years, the Commission creates an "attrition" proceeding in which adjustments to base rates will be made for changes in non-fuel costs, especially due to inflation. The Commission adopts a set of formulas for adjusting base rates based on changes to labor, non-labor, and financing costs that are out of the utilities'

67 4 CPUC 2d 698. The original AER percentage was two percent; it was later raised to different levels for each of the utilities, and then subsequently suspended.

control.[68] By limiting the types of cost changes that can be made in attrition year rate adjustments, there is some hope that utilities will still have an incentive to be efficient.

ERAM

Traditionally, utilities, intervenors, and Commission staff disagree strongly over utility forecasts for electric sales. In ratemaking, the revenue requirement (the total costs of service) for each customer class is divided by forecast sales to the class to determine electric rates to be recovered from that customer class. All other things being equal, a high sales forecast results in lower rates than a low forecast. Parties charge that utilities underestimate sales forecasts in order to increase rates and insure that revenue requirements are recovered. Thus, the sales forecast becomes a very important element of rate proceedings as intervenors and Commission staff fight to keep rates low.

Added to this tension is the concern that the importance of sales forecasts keeps utilities from pursuing conservation as aggressively as the Commission wants. Once rates are set, utilities have incentives to promote electricity sales; if a utility sells more than had been expected, it earns more revenue, which it is allowed to retain. Conversely, if a utility sells less than anticipated, it bears the burden of the revenue shortfall. Thus, under traditional cost-of-service ratemaking, utilities generally promote sales, certainly not a desirable strategy when the state, and the country, is trying to conserve energy.

In PG&E's Test Year 1982 rate case, the Commission adopts a revenue adjustment mechanism proposed by PG&E, Commission staff, and the CEC. This mechanism ensures that utilities recover the forecasted revenue requirement. If utilities collect more, it is

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68 7 CPUC 2d 394-400. This was the Commission decision in PG&E's 1981 General Rate proceeding (A.) 58546 for test year 1982.

refunded to ratepayers; if they collect less, a surcharge collects an additional amount the next year. The Commission believes that the Electric Revenue Adjustment Mechanism (ERAM):

> "...will reduce the time devoted to the issue of appropriate sales estimate levels to be used for ratemaking. It is especially difficult in this period to make accurate sales estimates because of the state of the economy and the inability to accurately quantify the effects of conservation which we are expecting our utilities to promote more vigorously in the future."[69]

The Formation of a Utility-Regulator Partnership

By the end of this period, utilities and regulators, despite controversy and conflict, have forged a complicated set of mechanisms and procedures to protect utility financial health and provide consumers with greater rate stabilizing. In return, California's regulators begin to take a more active role in protecting ratepayer interests and in utility plans for ensuring reliable electric service. This new partnership, an evolution in the historical regulatory compact between utilities and regulators, continues to evolve in the 1980's and early 1990's.

69 7 CPUC 2d 394.

CHAPTER IV

CHAPTER V

1982-1992 AND THE ROAD TO WORKABLE COMPETITION:

THE PARTIAL SHIFT FROM GOVERNMENT PLANNING TO MARKET SOLUTIONS

This period begins with mounting questions about the financial fate of the utilities. It ends with the state's IOUs regaining their financial health. This chapter traces the utilities' financial rehabilitation to four key events:

First, the state and national economic conditions improve dramatically over the previous period. Second, the Commission's strategy of increasing the role of energy efficiency and independent generation bears fruit. Third, the Commission's continued use of regulatory balancing accounts and rate adjustment mechanisms for the most part successfully insulate the utilities from market volatility and financial risk. And fourth, astute utility management practices pay off.

Toward the middle of this period, the Commission begins to shift from the command-and-control strategy familiar under the traditional regulatory compact in favor of a new policy emphasizing market-based regulatory solutions. This shift manifests itself most notably during the 1980s in Commission programs governing the telecommunications, natural gas and transportation industries. In the electric industry, the Commission pursues least-cost, reliable, environmentally sound energy service throughout this period, but turns increasingly toward market approaches to achieve its goal, emphasizing workable competition and competitive bidding. By the end of this period, performance based ratemaking, opportunity cost transmission pricing, market rates for wholesale generation purchases, and the prospect of an expanded competitive bidding process which includes both demand and supply resources all signal a sustained movement away from traditional regulatory approaches among state and federal regulators alike.

As the 1990s begin, events within the industry and passage of the first comprehensive piece of federal energy legislation since 1978 pave the way for still greater change : the first competitive auction in California promises to provide answers to questions surrounding the procurement debate for nearly a decade; reforms of the Federal Power Act and the Public Utility Holding Company Act contained in the National Energy Act of 1992 promise to increase competition as a new class of provider--the exempt wholesale generator--enters the generation sector; the Commission's continued examination of the prospects for head-to-head competition between supply- and demand-side resources is likely to further bolster competition; and finally, the early retirement of large nuclear generating facilities in California and elsewhere in the U.S. leaves many speculating about the loss of additional nuclear capacity looming on the horizon.

In light of these events, some begin to question whether a changing electric industry has outpaced the development of Commission regulatory programs designed to govern the industry. Some assert that while the Commission moves aggressively to establish a workably competitive electric market with one hand, the other hand relies on a variety of incompatible regulatory mechanisms established when utilities faced considerably different circumstances, or when vertically integrated utilities dominated the energy infrastructure.[70] *In 1992, the Commission announces it will reexamine its regulatory approach.*

The Utilities Face Improved Economic and Financial Conditions

This period is marked by vastly improved economic and financial conditions. In particular, interest rates, fossil fuel prices, and inflation--the major culprits wreaking havoc on the utility's financial integrity during the previous period--decline significantly, then stabilize (see Figures V-1 through V-3).[71] Except for 1985-1986, all three IOUs experience increased sales over this same period (See Figure V-4).

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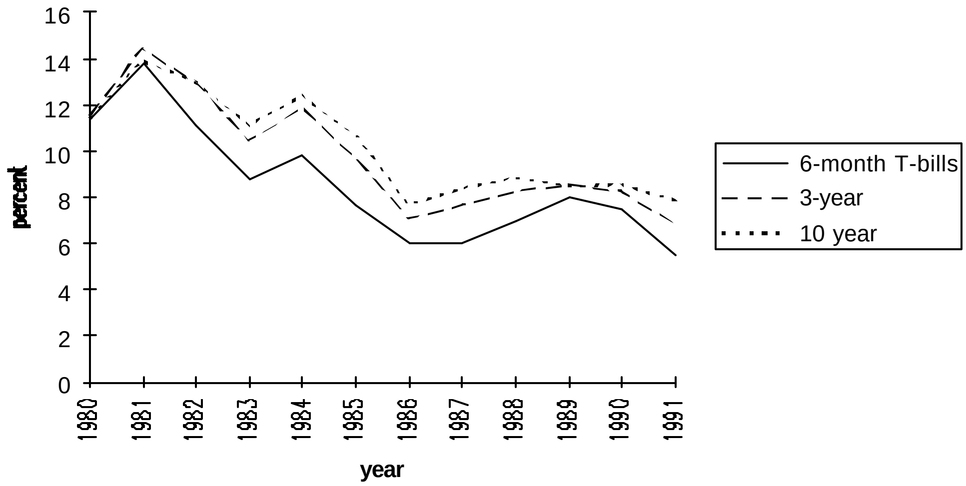
70 In 1991, 32% of Edison's total energy requirement comes from QFs, for PG&E, the QF contribution to total energy requirements is 24%, and for SDG&E, it is 6%. (Source: CPUC Division of Ratepayer Advocates.)

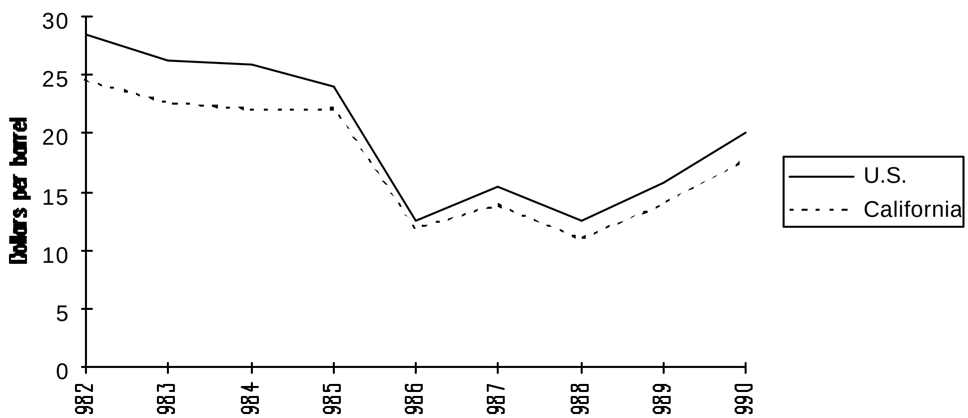
71 The only marked increase in oil prices comes in response to the 1990 Gulf War, which has only a limited affect on the cost of utility operations thanks to the utilities' greatly reduced dependence on oil. To illustrate, in 1981 the state's three major IOUs use a weighted average of approximately 500 barrels of fuel oil to provide one million kilowatt-hours of electricity. By 1987, that weighted average drops below 20 barrels. (CPUC Annual Report, 1987, p. 17.)

Figure V-1
Interest Rates. 1980-1991



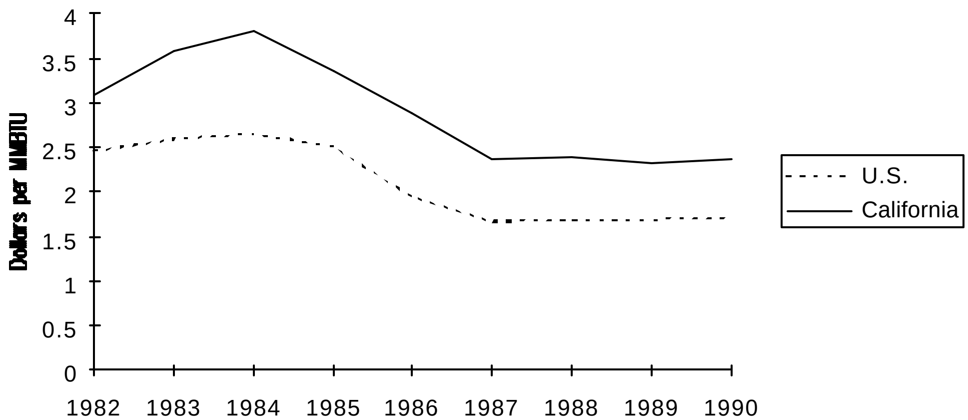
Source: 1992 Economic Report of the President, February 1992, pp. 378-379.

Figure V-2a
Wellhead Crude Oil Prices, 1982-1990



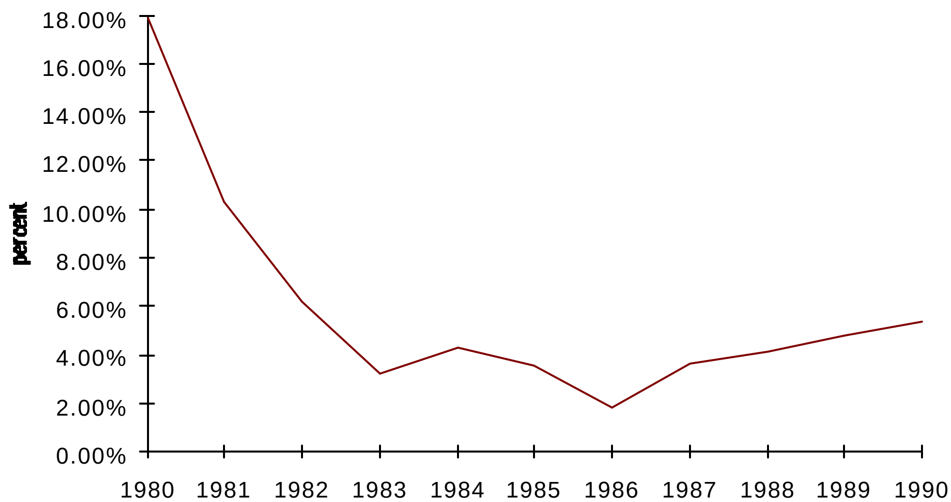
Source: Basic Petroleum Data Book, Table 9.

Figure V-2b
Wellhead Natural Gas Prices, 1982-1990



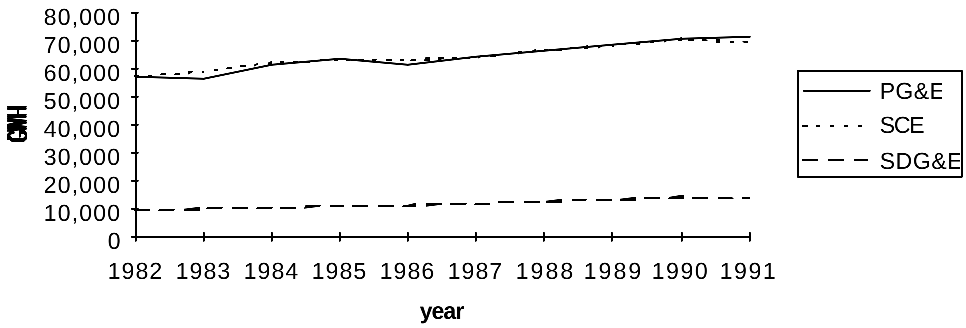
Source: Basic Petroleum Data Book, Table 9.

Figure V-3
Change in Consumer Price Index



Source: Hyman, page 146.

Figure V-4
Utility Sales, 1982-1991



Source: Utility Financial Reports.

Improved Conditions Strengthen the Utilities Financial Position

The utilities' financial situation improves markedly from 1982 through 1992. For example, PG&E's market-to-book ratio rises steadily, breaking one hundred percent in 1985.[72] The company's 1991 year-end ratio is over 175 percent.[73] Beginning in 1988, PG&E's total return on common stock consistently outpaces the industry average.[74]

Edison, whose AFUDC in 1980 accounts for over 50% of booked earnings, attributes approximately 3% of its earnings to AFUDC in 1989, and less than 5% by 1991.[75]

For all three of the utilities, actual return on equity exceeds that allowed for most of

72 R.86-10-001, Figure 2-11. Edison's and SDG&E's ratios break the 100% level at about the same time.

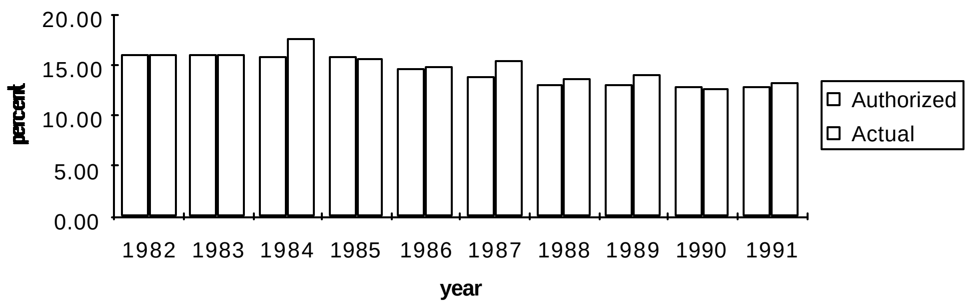
73 In 1991, Edison's ratio is 181 percent; SDG&E's is approximatley 170 percent.

74 PG&E Annual Report to Shareholders, 1991.

75 See 3Rs, page 24, and Edison's 1991 Annual Report to Shareholders.

this period (See Figures V-5a, V-5b, V-5c). From a national perspective, even with the turbulent decade of the 1970s, 1982 to 1992 sees the financial performance of California's IOUs stack up favorably against the industry as a whole. At 18.81%, Edison shareholders enjoy the third highest average return in the nation.[76] Between 1991 and 1992, all three utilities earn a return on equity that ranges from two to five percent above the industry average.[77]

Figure V-5a
PG&E Return on Equity

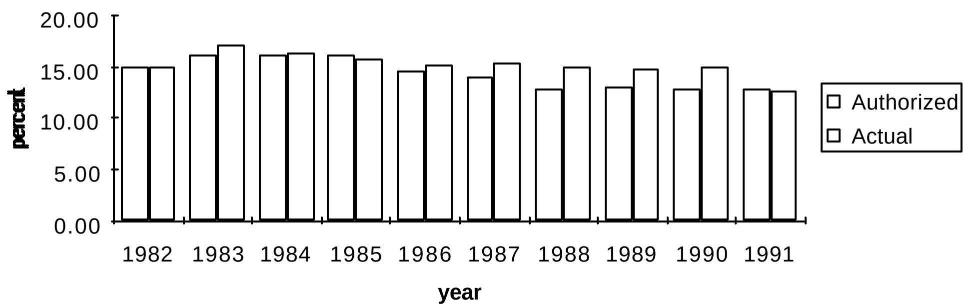


Source: Response to DSP data request, November 1992.

76 See National Association of Regulatory Utility Commissioners, 1991. The report measures stockholder returns based on changes in stock prices and cash dividends paid to common stockholders. Attractive returns are, on average, common to utilities around the country during this period. Average utility shareholders earned an average internal rate of return of 14.01%, while the Standard & Poor's Index of 400 Industrial returned 12.43% during the same period.

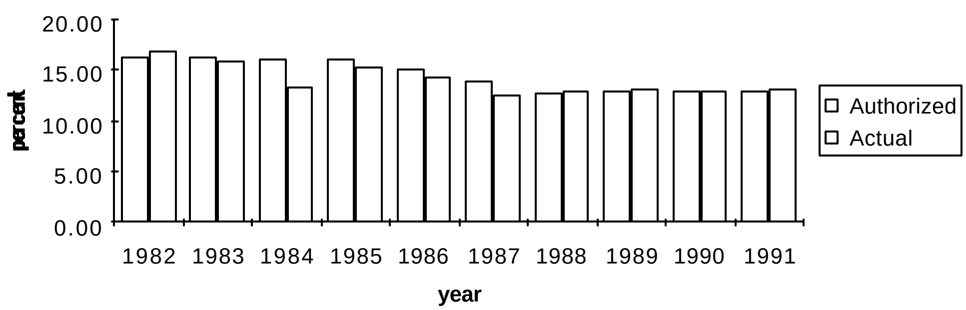
77 Compiled from Electric Utility Credit Review, Mabon Securities Corp., March 20, 1992.

Figure V-5b
SCE Return on Equity, 1982-1991



Source: Response to DSP data request, November 1992.

Figure V-5c
SDG&E Return on Equity. 1982-1991



Source: Response to DSP data request, November 1992.

By the Spring of 1992, San Diego's credit direction receives a "positive" single A rating from Standard & Poor's; both Edison and PG&E receive a double and single A, "stable" direction rating, respectively.[78]

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78 Ibid.

CHAPTER IV

1982-1985: Continued Regulatory Focus on Price Stability and Resource Diversity

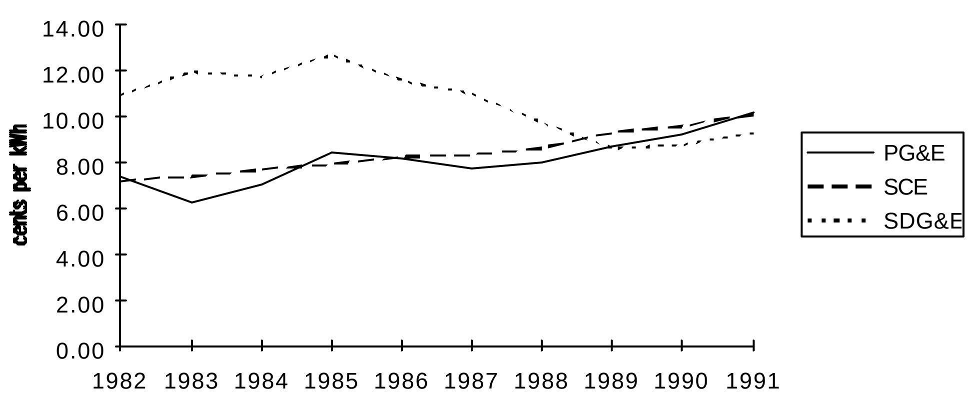
Building on policies established in the 1970s, by the early-to mid-1980s the Commission puts in place a broad set of regulatory programs designed to accomplish two principal objectives:

1. **Continue to protect consumers from the uncertain rates, and utilities from the financial risks, that might otherwise accompany volatile economic conditions.**

To accomplish this objective, the Commission continues to insulate the utilities from "unforeseen" financial risk through the continued use of financial adjustment mechanisms and balancing accounts. The Commission recognizes that this strategy places significant financial risks on utility consumers; it also successfully dampens utility price increases. Edison's average electric rates stabilize at about 8 cents/kWh during this period. PG&E's average rate falls from 8 to 7 cents/kWh between 1982 and 1983, but climbs back to 8 cents in 1985. SDG&E's averages rates, hovering at approximately 11.5 cents in 1982, peak at almost 13 cents/kWh in 1983 and end at about the same level in 1985 (See Figure V-6.) In response to the added risks placed on consumers, the Commission increases its reliance on proceedings to assess, *ex post*, the reasonableness of utility management actions.

Figure V-6

Average Electric Rates, 1982-1991



Nominal dollars. Source: Response to DSP data request, November 1992.

2. **Slow rapidly rising utility costs by reducing fossil fuel use, delaying the construction of additional utility plant, and making more efficient use of energy resources.**

The Commission pursues this objective principally through active participation in utility resource planning and acquisition. The Commission's active role in utility resource procurement helps to balance the risks shifted to consumers through balancing accounts and rate adjustment mechanisms. This increased Commission role also comes with the hope of tempering the skyrocketing costs of fossil fuels and plant construction by aggressively targeting both QF development and increasing utility investment in energy efficiency. The Commission's strategy leads to both successes and failures.

Commission Policy and QF Development

With the rapid entrance of qualifying facilities onto the electric services scene during the early 1980s, the Commission finds itself once again managing an evolving regulatory compact. The bulk of the risks associated with the development and operation of electric generation--traditionally borne by the utility and its customers--shifts to unregulated qualifying facilities. But with the risks, so go the rewards--a less than preferable prospect for utility managers anxious to maintain profitability.

QF Adolescence[79]

[79] The following summary draws from, Ahern, William R., "Implementing Avoided Cost Pricing for Alternative Electricity Generation in California," pp 404-419, in New Regulatory and Management Strategies in a Changing Market Environment, edited by Trebing, Harry M., and Mann, Patrick C., as part of the 1987 Michigan State University Public Utilities Papers. Much of the data comes from Doying, Richard, "Policy Implications of the ISO4 Energy Price Cliff," an unpublished study for the Division of Strategic Planning, California Public Utilities Commission, October 1992.

CHAPTER IV

In 1982--as part of OIR 2--the Commission crafts programs designed to carry out the policies embodied in California's Small Power Producers Act (1976), PURPA (1978), and the Commission's 1979 decision encouraging the development of cogeneration and alternative resources in California (D.91109).[80]

The Commission's policy of "encouraging QF development" plays a leading role in the early stages of the Commission's QF programs. Following FERC's lead, the Commission adopts full avoided cost, and ratepayer indifference, as the standards for QF pricing. Second, the Commission requires the utilities to develop standard QF contracts, or Standard Offers, based on both short and long-run avoided cost.[81] The Commission's decision stems from utility fears that a large number of individually executed contracts will lead to a quagmire of reasonableness reviews, and the Commission's own concerns over utility monopsony power.

Development of contracts tied to the utility's short-run avoided cost proceeds relatively smoothly. The utilities submit, and the Commission approves, a portfolio of three short-run standard offers. Standard Offers 1 and 3 pay for energy and capacity on an as-available basis; Standard Offer 2 pays for energy on an as-available basis, but unlike 1 and 3, the contract pays fixed prices for capacity for up to 30 years. The fixed capacity payments are contingent upon QF performance. By the end of 1982, QF projects totaling just over 1,500 MWs sign contracts tied to the utilities' short-run avoided cost.

The development of contracts for long-run avoided costs goes less smoothly. Fearful that falling oil prices (see Figure V-2) and potential transmission constraints might threaten future QF development, the Commission takes additional steps to bolster the fledgling

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80 See D. 82-01-103. See also Chapter IV for a more detailed discussion of PURPA.

81 See D.82-01-105.

industry.

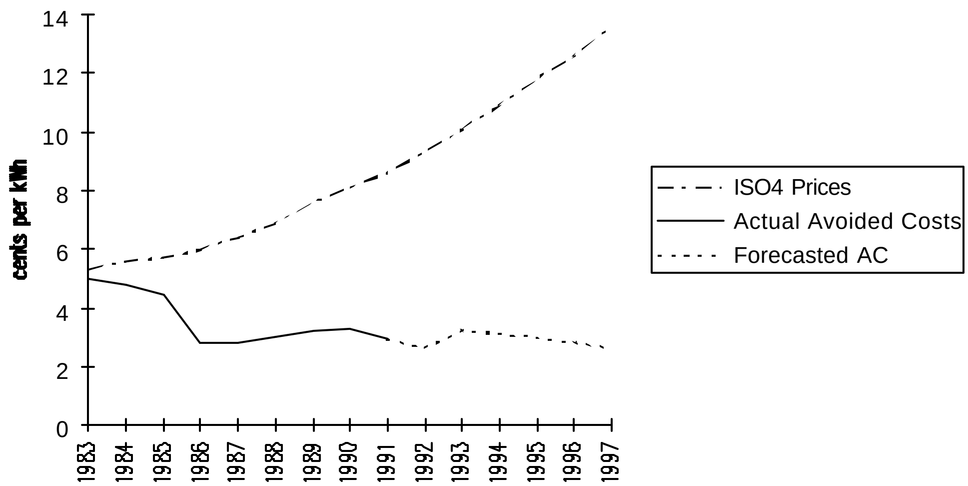
First, in response to PG&E's concern regarding electric transmission constraints in the Northern portion of its service area, the Commission limits the amount of QF capacity PG&E must accept. The Commission also establishes a monitoring and queuing program designed to provide all QFs a fair opportunity to provide service in light of these constraints.[82]

Second, in the belief that capital-intensive QFs will have an easier time acquiring financing if certainty about the amount and timing of payments is greater than that of short-run contracts, the Commission moves to develop QF contracts tied to the utility's long-run avoided cost. Rather than wait for the results of what promises to be an extremely difficult--and in all likelihood time-consuming--task of crafting a comprehensive methodology, the Commission abandons its customary litigation process and instead orders the utilities to enter into settlement negotiations with the interested parties.

The negotiations, though difficult, bear fruit. From them emerge standard contracts based on the utilities' forecast of future fuel prices and other key assumptions needed to estimate long-run avoided costs. The contracts are called Interim Standard Offer 4 (ISO4). ISO4 includes different options for energy and capacity payments and are intended to accommodate a wide range of resources and technologies. The utilities submit the contracts to the Commission; the Commission approves them in September 1983. Figures V-7a and V-7b show the fixed energy prices for ISO4 sales to PG&E and SCE.

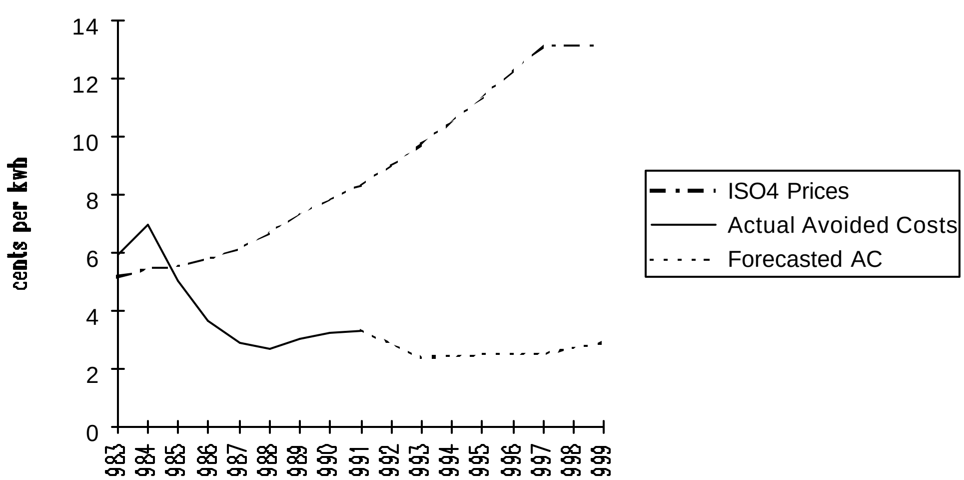
82 See D.84-08-037.

Figure V-7a
QF Prices - SCE



Nominal dollars. Avoided cost forecast using gas prices from CEC's 1991 Fuels Report.

Figure V-7b
QF Prices - PG&E



Nominal dollars. Avoided cost forecast using gas prices from CEC's 1991 Fuels Report.

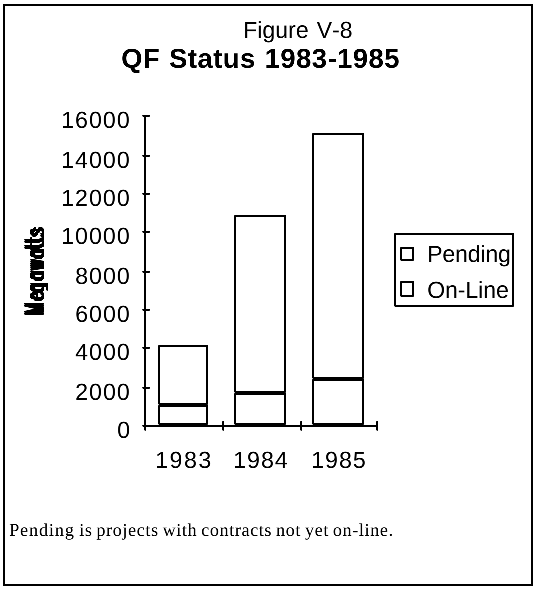
CHAPTER IV

QF Subscription Exceeds Expectation

Conventional wisdom predicts that no more than 1,000 MW of QF projects will sign ISO4 contracts, but for a variety of reasons, conventional wisdom underestimates the market response to ISO4.[83] By 1984, QF projects totaling more than 10,000 MWs are either on-line or have signed contracts; by 1985 the number exceeds 15,000 (Figure V-8). Fearful that there is no end in sight to the subscription, and recognizing the limits of utility resource requirements, Commission staff and PG&E file a joint petition calling on the Commission to suspend the ISO4 subscription.

The Commission suspends ISO4 in April 1985. In the Spring of 1986, recognizing that the value of additional generating capacity is diminishing rapidly due to the large amount already reaped, the Commission also suspends Standard Offer 2--the contract offering levelized fixed capacity payments for up to thirty years in return for a specified level of performance.

83 Ahern, op. cit., p. 411.



Factors Driving the Response to ISO4

Attempts to explain the phenomenal response to ISO4 vary and prove controversial. Nevertheless, the explanations share some common themes. First, independent producers realize that establishing a methodology for a final long-run standard offer will require considerable time. Second, technological advances in the cogeneration market, coupled with decreasing fuel prices, increase both cost-effectiveness and project profitability under ISO4. Third, falling oil prices make the ISO4 contract's fixed prices increasingly attractive. Fourth, the ability to determine cash flows under the interim long-term contracts with some certainty bolsters support from the financial community. Fifth, the transmission capacity available in PG&E's constrained area is offered on a first-come, first-serve basis, at no cost to the QF. And sixth, anxieties mount over speculation that federal tax credits for the development of renewable resources may be eliminated.

Fixed ISO4 Prices Differ from Utility Avoided Cost

By 1985, the utilities' actual avoided cost is below the forecast adopted in 1983 for ISO4. That gap widens throughout the remainder of the 1980s; in 1992, forecasts predict a further widening of the gap. (See Figures V-7a and V-7b).[84]

Under the terms of ISO4, the 3,500 MWs of renewable projects holding ISO4

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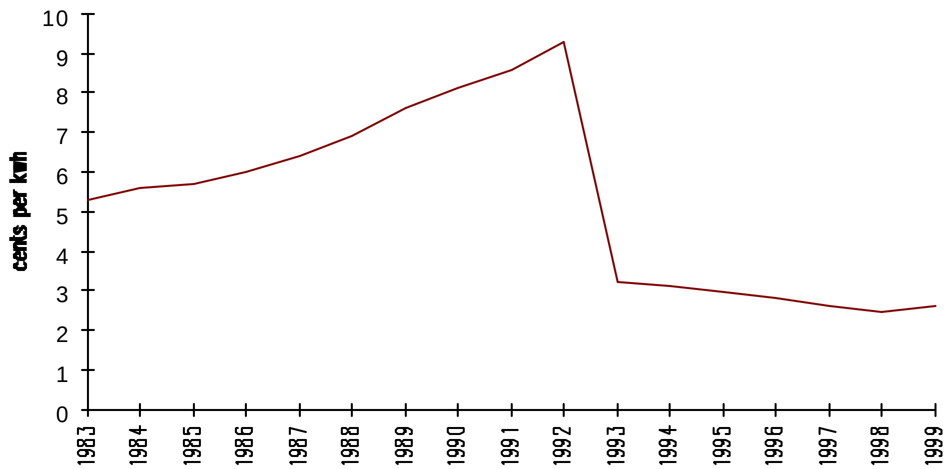
84 Doying, R., op. cit.

contracts will switch from fixed payments based on forecasts of avoided cost to the utility's *actual* avoided cost ten years after the date the project becomes operational. By the end of the decade, the bulk of these contracts will have switched to actual avoided cost payments, significantly reducing future payments for energy services rendered (see Figure V-9).[85]

Figure V-9
ISO4 Price Stream



Nominal dollars. Avoided cost forecast 1993-1999 using gas prices from CEC's 1991 Fuels Report.

Demand-Side Management Comes of Age

In 1982, utility investment in DSM continues to rise. The Commission encourages the aggressive pursuit of efficiency savings, recognizing that success will reduce utility AFUDC--an increasingly worrisome contributor to utility earnings during the previous period. The Commission further recognizes that conservation can reduce the skyrocketing fuel expenses

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85 In 1991, Edison payments to QFs exceeded $2 billion.

and plant financing costs plaguing the industry during the 1970s, and relieve pressure on the Commission to increase the utilities' return on equity at a time when further rate increases are particularly unpalatable.

Recognizing as well that the regulatory compact's historic reliance on traditional cost recovery methods would frustrate goals for energy efficiency and conservation, the Commission adopts the Energy Rate Adjustment Mechanism in 1982.[86]

The creation of ERAM marks the continued departure away from the well-worn approach that characterized the regulatory compact between the 1940s and the first oil embargo.[87]

In D.93887, the Commission makes the case for modifying its regulatory program to support energy efficiency and conservation goals:

> ...the establishment of a revenue adjustment mechanism is especially important to eliminate any disincentives for a utility to promote conservation and to pursue the policies enunciated by this Commission on achieving *all cost-effective conservation*.[88]

Aside from the desire to put utility investment in demand-side management at the center of management focus, support for ERAM is further strengthened by the Commission's desire to reduce regulation's administrative costs. Already knee-deep in a wide array of balancing accounts previously grafted to its regulatory programs, the Commission believes ERAM will "...reduce the time devoted to the issue of appropriate sales estimate levels to be

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86 Briefly, ERAM decouples utility electric sales from revenues; that is, under ERAM the amount the utility is allowed to recover is independent of the amount of electricity the utility sells--a dependence once considered a "mainstay" of traditional rate-of-return regulation. See Chapter IV for a more detailed history of ERAM.

87 ERAM was also adopted, like the other mechanisms, as a means to reduce utility financial risks.

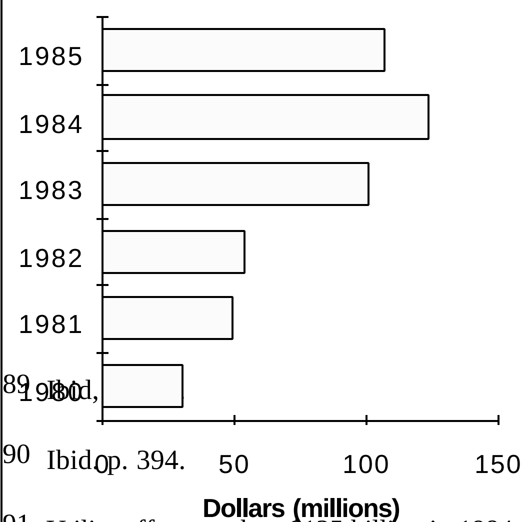
88 7 CPUC 2nd, 392, emphasis added.

used for ratemaking."[89] Moreover, the Commission explains that ERAM--like most of the regulatory modifications designed to insulate the utilities from unforeseen financial risk--is a product of the dynamic nature of the utility's environment:

> It is especially difficult in this period to make accurate sales estimates because of the state of the economy and the inability to accurately quantify the effects of conservation which we are expecting our utilities to promote even more vigorously in the future.[90]

The Commission's DSM policies are largely successful. Between 1980 and 1985, the three IOUs' investment in conservation increases by about 250%. Total expenditures grow by about $76 million, from $31 million in 1980 to just over $107 million in 1985 (Figure V-10).[91] IOU investment over this same period achieved energy savings of almost 12 billion kilowatt-hours.[92]

Figure V-10
DSM Investment



1985 dollars. Source: Calwell & Cavanagh, July, 1989.

DSM investment by PG&E increases by approximately 300%, exceeding $56 million in 1985. Similar investments by Edison and SDG&E also increase dramatically. Edison's investment peaks at $63 million in 1984, an increase of

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89 Ibid,

90 Ibid., p. 394.

91 Utility efforts peak at $125 billion in 1984. See Calwell, C.J., and Cavanagh, R.C., The Decline of Conservation, p. 9.

92 Ibid. Derived from Figure 2.

approximately 350% over 1980 expenditures. By 1983, SDG&E increases investment in conservation by almost 500%, devoting nearly $13 million to their efforts.

The Use of Balancing Accounts Increases

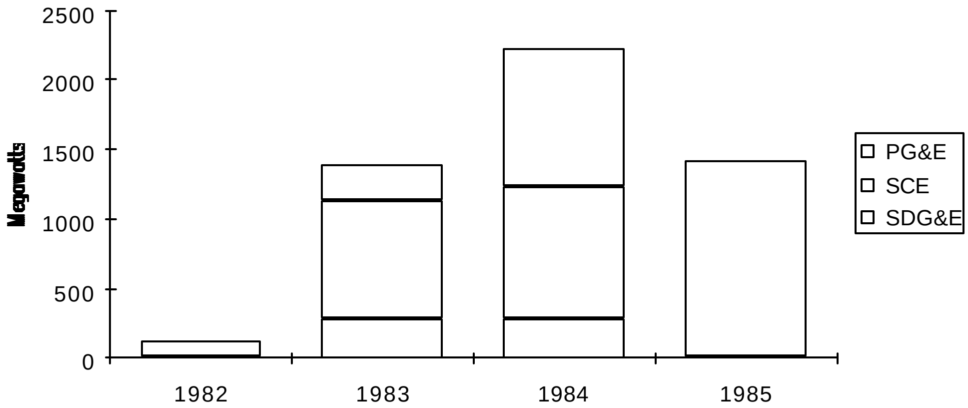
In 1982, the Commission's concern over the harsh financial effects of the economic conditions of the 1970s and early 1980s does not wane. In fact, the Commission incorporates continued reliance on balancing accounts and rate adjustment mechanisms in its QF and DSM policies and programs.

In 1983, with considerable amounts of new, utility-sponsored generating capacity under construction and slated to come on line during the first half of the 1980s, the Commission creates yet another account--the "Major Additions Adjustment Clause," or MAAC. Its purpose is two-fold: First, MAAC allows the utility to begin recovering the costs of major capital additions arising between general rate cases. Second, MAAC offers an opportunity to apply greater scrutiny to the prudence and reasonableness of the utilities' management of major plant construction.

Utility-sponsored Plant Construction

Between 1982 and 1985, the utilities bring on line approximately 5,200 MWs of new plant capacity (see Figure V-11).

Figure V-11
Utility Capacity Additions, 1982-1985



Source: Utility Annual Reports.

PG&E adds approximately 2,800 MWs of capacity to its system. Over 1,100 MWs of those additions come from the first nuclear unit at Diablo Canyon; 1,110 MWs come from hydroelectric and pumped storage resources, with the remaining 500 MWs developed from geothermal and wind resources.

SDG&E adds roughly 600 MWs of company-owned nuclear capacity to its system during this period, while Edison adds approximately 1,800 MWs of additional nuclear capacity. Some of these plants--particularly nuclear facilities--under construction since the 1970s, lead to cost overruns and operational problems. The cost overruns and delays associated with these plants contribute to the Commission's policy of accelerated QF and DSM development.

Striking the Balance

The Commission's adoption of new balancing accounts or rate adjustment mechanisms between 1982 and 1985 (often established at the utility's behest) signals the continuing evolution of the means employed by the Commission to uphold the regulatory compact. In its efforts to uphold the just and reasonable rates standard, the Commission delves more deeply into utility operations and decision making. Resource plans receive close scrutiny, and a host of Commission proceedings look retroactively at the prudence of utility decisions.

As a result, both the sheer number and analytical complexity of regulatory programs grow and administrative costs increase. The Commission is at once accused of micromanaging utilities and failing to adequately scrutinize them.

1986-1992: The Commission Considers Reform

During this period, the Commission expresses its belief that changing economic, financial, legal, and policy conditions may require program modification, but insists that careful consideration must preceed regulatory reform. This belief is not new, however. As early as March of 1981, the Commission expresses doubts about the long-term viability of a regulatory strategy that grafts balancing accounts to its traditional approach, and convenes a symposium to explore the merits of undertaking substantive reform.[93]

Speaking at the Symposium, the President of the Commission expresses concern over the increase in the breadth and number of balancing mechanisms:

> ...as Commissions reduce utility exposure to uncontrollable or unforeseeable risks through balancing accounts and adjustment mechanisms, incentives that once encouraged operating efficiency are...reduced.[94]

As evidence that the Commission's regulatory programs designed to uphold the compact might no longer mesh with the contemporary electric utility industry, the

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93 Steven Westly, Editor, Energy Utilities: The Next 10 Years, July, 1981.

94 Ibid., Comments of President John E. Bryson, p.3.

Commission's President points to utility managers disgruntled over poor returns, consumers irate over higher rates, and PUCs skeptical over whether utilities are operating efficiently and making optimal resource procurement decisions.[95]

Confronted by these concerns, the Symposium agenda lists three alternative industry structures for consideration. Each would arguably require considerable amendments to the traditional regulatory compact: 1) deregulation of the electric services market that allows utility affiliates to participate; 2) a "full service utility industry," that expands far upstream to fuel supplies and far downstream to small scale power and expanded DSM services; and, 3) government ownership of the industry.

The symposium elicits useful information, but the Commission rejects sweeping reform, opting instead to adopt ERAM in December 1981. It isn't until the end of 1985 that the Commission again takes up the mantle of reform in earnest.

Risk, Return, and Ratemaking

By 1985, aided by improved economic conditions, the Commission's strategy pays off: utility management by and large succeeds in bringing costs under control; energy prices begin to level off; and as a result, the utilities' financial risk lessens. This again prompts the Commission to consider regulatory reform. In particular, the Commission questions anew the wisdom of continuing with balancing accounts and rate adjustment mechanisms in light of considerably more favorable conditions. In December of 1985, the Commission announces the need for regulatory reform:

> "The history [of these mechanisms] is replete with references to economic volatility, uncertainty, extraordinary inflation and cost escalation, and stagnant energy demand growth. ...[T]he times which gave rise to the creation of [these] ..regulatory

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95 Ibid., p. 4.

> mechanisms were marked by conditions dramatically different from those of the present day. Lower inflation and interest rates, less volatile demand swings and stabilizing rates exist, creating an attractive economic climate for the utilities. This is reflected in the actual earnings of the utility, some of which exceed authorized rates of return..."[96]

In October of 1986, the Commission issues an Order Instituting Rulemaking (OIR) and asks parties to comment on the recommendations of the Commission's Policy and Planning Division's report, "Risk, Return, and Ratemaking," or Three Rs. The report recommends eliminating both ERAM and the attrition mechanism.[97]

The Three Rs report concludes that ERAM and the attrition mechanism achieved the Commission's goals, exceeded their useful lives, and should therefore be discontinued. Among other things, the report cites larger rate bases, ample generating capacity, improved utility earnings, and reduced fuel and operating costs to support its recommendation.

The report calls on the Commission to rebalance its regulatory policies, placing greater weight on the growing threat of customer bypass and less on the diminished threat of financial collapse.[98] Eliminating ERAM and the attrition mechanism, the report asserts, offers a potent strategy to combat uneconomic bypass and thus promises to achieve the

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96 D.85-12-076, pp. 17-20.

97 R.86-10-001, pp. 2-4.

98 There are two types of "bypass"--economic and uneconomic. Economic bypass occurs when the customer pursues an option whose cost falls below the utilities marginal cost to deliver the service. Uneconomic bypass results from customers turning to services whose cost exceed utility marginal cost. Uneconomic bypass is particularly problematic when customers have access to options whose cost falls below utility **rates** but above utility **marginal cost**. The Commission discourages uneconomic bypass since it results in an inefficient allocation of resources.

rebalancing called for in the report.[99] The report goes on to argue that returning the risk of sales revenues and non-fuel expenses to the utility provides utility management with both the "right" incentive and the flexibility to reduce costs and better market its commodity--electricity.[100]

Bifurcating the Electric Industry's Customers

In its decision following the Three Rs report, the Commission proposes to adopt the report's "Core/Non-Core Strategy" for the electric industry.[101] The core/non-core strategy would remove ERAM for "non-core customers who are likely to leave the system through self-generation...". The Commission could thus allow the utilities to negotiate "special contracts" with these non-core customers. According to the proposal, ERAM and the attrition mechanism would remain intact for the "core" customers.[102] The contracts would allow the utility to differentiate among customers, deviating from average cost pricing principles developed under the traditional regulatory compact.[103]

Under the Commission proposal, the utility would enjoy greater flexibility to compete for large customers who enjoy alternatives to utility service. But with increased flexibility

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99 Utilities and regulators focus on uneconomic bypass for fear that if left unmanaged, it will lead to exorbitant rate increases.

100 In considering the elimination of ERAM, the Commission exhibits little concern about the threat of reinstating the disincentive for utility investment in energy efficiency and conservation, stating "...utility operating costs on the margin are far below current rates, making short-term, utility-financed, conservation programs uneconomic." (OIR No. 86-10-001, p. 1-2.) Growing numbers disagree considerably with this view.

101 See D.87-05-071.

102 Risk, Return, and Ratemaking, p. 108.

103 24 CPUC 2d 421. The Commission's proposal classifies customers with loads of one megawatt or more as non-core.

would come a trade-off: eliminating ERAM and attrition would place the utility at risk for recovering costs allocated to the non-core class.

The Commission never implements the core/non-core strategy for the electric industry. Between the release of the Three Rs report in 1986 and the period following the Commission's 1987 proposal to bifurcate customers, the threat of bypass gains primacy over the report's initial call for broader regulatory reform. By 1988, special contracts significantly reduce the threat of bypass. Finally, concerned that the administrative burden of dividing customers between core and non core is too complex, the Commission ultimately chooses not to adopt the core/non-core strategy. The Commission instead retains it's special contracts policy, and creates an Expedited Application Docket to rapidly process these new contracts[104].

<u>The End of the Decade: The State Catches its Breath</u>

Suspended in 1985 and 1986, respectively, Interim Standard Offer 4 and Standard Offer 2 remain so throughout the remainder of this period[105]. As a result, the number of QFs brought on line in California levels off by the end of this period; and construction by IOUs remains relatively flat from 1986 to 1991. (See Figure V-12).

The Commission's QF and conservation policies during the first half of the decade manage costs by delaying utility investment in new plants. Further, with the successful development of QFs, and the completion by 1985 of utility projects begun in the 1970s, the Commission finds little need for resource additions through the end of the decade. And though SDG&E identifies new resource requirements beginning in 1987, it delays acquisition

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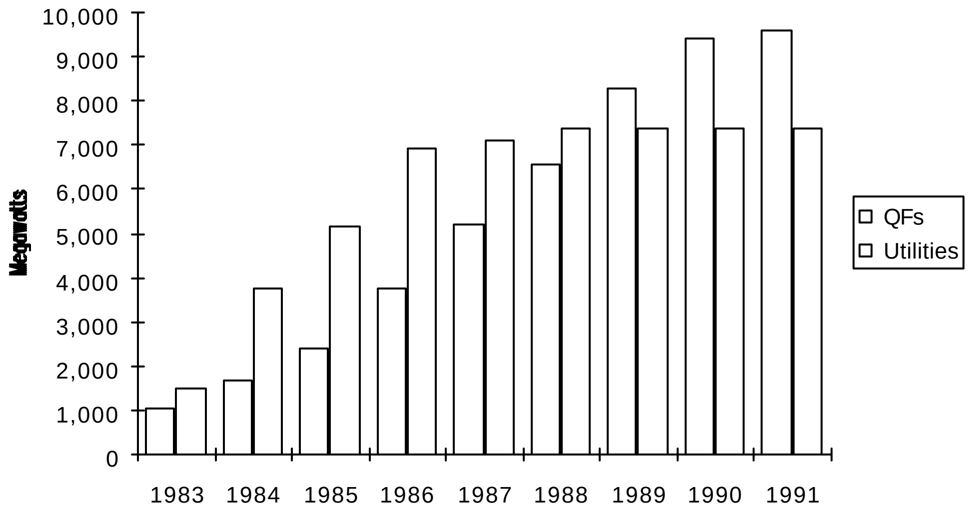
[104] The Commission will close the Docket in 1990.

[105] San Diego Gas and Electric was authorized to offer 100 MW under Standard Offer 2 in 1987. None of the projects that were awarded an SO2 contract have been built.

pending the disposition of the application to merge with Edison.[106]

Figure V-12

Cumulative Capacity Additions - 1983-1991



Source: Utility Annual Reports and the utilities' Cogeneration and Small Power Producer Quarterly Reports.

The Current State of Contracts

Of the QF projects that sign contracts under both the short- and long-run avoided cost offers, approximately 9,500 MWs come on line by 1992; over half of those contracts are held by cogenerators. Fifty-four percent, or just over 5,200 MWs, hold ISO4 contracts. Cogenerators hold fully one-third of the 5,200 MWs of ISO4 contracts currently on line and serving California's utilities, leaving approximately 3,500 MWs of renewable resources holding ISO4 contracts tied to prices forecast in 1982.

In 1991, Edison purchases approximately 32 percent of its total energy requirement (72 million megawatt-hours) from qualifying facilities. Roughly half, or 16% of total

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106 In 1991, the Commission denies the company's (and Edison's) request. See D.91-05-028.

purchases, stem from contracts with Edison's affiliate Mission Energy. Approximately 25% of PG&E's 1991 total energy requirement (80 million megawatt-hours) is filled by QFs. QFs make up 6% of SDG&E's total energy requirement (16 million megawatt-hours) in 1991.

Generation and Utility Financial Health

Between 1986 and 1990, on the heels of the unforeseen response to the ISO4 solicitation, 2,000 MWs of additional utility-sponsored resources come on line. (See Figure V-12). During this same period, the financial health of the utilities continues to strengthen. This comes despite PG&E's losses resulting from the Diablo Canyon settlement and disallowances Edison and SDG&E absorb over certain power contracts.[107] As the 1980s come to a close, the need for additional resources looms on the horizon.

PG&E: Between 1986 and 1992, PG&E adds 1,200 MWs of new company-sponsored generating capacity to its system. Bringing the Diablo Canyon nuclear generating facility on line proves troublesome, however, and the company is forced to spend considerable time and effort overcoming operational and financial challenges.[108] Some wonder if Diablo Canyon's 2,190 MWs will ever become a permanent fixture on the PG&E system.

But in 1988, PG&E, California's Attorney General, and the Division of Ratepayer Advocates submit, and the Commission approves, a negotiated settlement designed to resolve the mounting controversy surrounding the Diablo Canyon plant.

The settlement is significant for two reasons: First, it marks yet another significant

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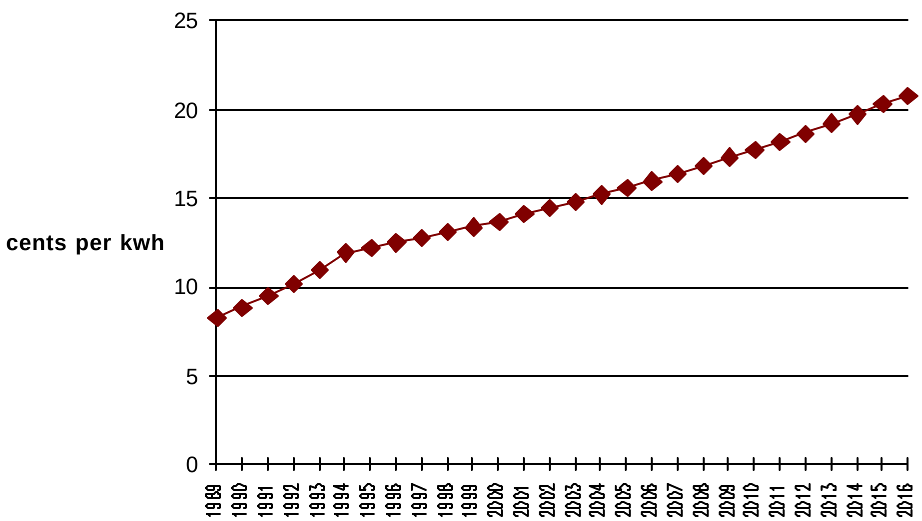
107 Edison's disallowances are linked to power contracts signed with projects partially owned by Mission Energy; San Diego's result from contracts related to the Southwest Power Link and with Public Service Company of New Mexico.

108 Originally estimated to cost approximately $500 million, Diablo Canyon's ultimate cost exceeds $5 billion.

departure from the cost-recovery approaches established under the traditional regulatory compact. The settlement abandons the traditional rate-of-return approach and opts instead for an approach that ties cost recovery to plant *performance*. While traditional rate-of-return regulation looks to the amount of money prudently invested as its yardstick for return on utility investment, PG&E's success in recovering expenses incurred at Diablo Canyon is directly linked to the amount and quality of service delivered by the plant. The prices paid for power produced at Diablo Canyon vary over time and are set by the terms of the approved settlement (See Figure V-13).

Figure V-13
Diablo Canyon Prices



Source: Diablo Canyon Settlement. Assumes CPI escalation equals 4% after 1994.

Though the Diablo Canyon settlement avoids what many predict will be several years of expensive litigation, PG&E's balance sheet does not escape unscathed. PG&E's book value per share drops from $18.68 in 1987 to $16.79 in 1988; the Company reports a reduction in net income of "...$576 million ($1.43 per share) as a result of the Diablo Canyon settlement and adjustments for various non-Diablo Canyon costs."[109] Also in 1988, PG&E declares a loss of $0.10 per common share.

1988 represents only a temporary setback for PG&E shareholders, however. Buoyed by the superior performance of the Diablo units, PG&E's earnings increase rapidly. By 1990 earnings increase by more than 40% over 1987.[110] The company's market to book ratio rises from 115% to 140% over the same period.

Edison: Like PG&E, Edison also adds new resources to its system, including a 25% equity share in three Palo Verde nuclear generating units. Edison's share in the project totals approximately 700 MWs.

Though Edison is disallowed certain expenses related to QF contracts signed with Edison's affiliate, Mission Energy, the company nonetheless improves its financial position during this period. From 1986 to 1990, earnings rise steadily, increasing by approximately 2.5%. Over this same period, the company's return on equity averages 15%; its market-to-book ratio climbs from 137% in 1987 to 150% in 1990.[111]

SDG&E: Apart from SDG&E's 25% equity share in the San Onofre Nuclear Generating Station, the company relies largely on power contracts to meet resource requirements during this period. Contracts fill approximately 30% of SDG&E's total energy requirements in 1992.

As with Edison, the Commission disallows certain expenses related to contracts SDG&E executes during this period. Despite this setback, the company enjoys, like PG&E

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109 PG&E 1991 Annual Report to Shareholders, p. 18.

110 In 1990, earnings from Diablo Canyon operations account for approximately 46% of total earnings.

111 1991 Annual Report to Shareholders.

and Edison, a position of strong financial health. From 1986 to 1990, SDG&E's return on equity averages just under 15%. Earnings fluctuate during the period but increase nonetheless.

Determining LRAC and Market-based Regulatory Solutions

As the utilities' financial position strengthens and a significant amount of both utility-sponsored and QF resources come on line in California during the mid- to late-1980s, the Commission attempts to develop a new regulatory approach for the electric industry. Central to that approach is the Commission's general policy shift toward solutions that rely less on government management and more on market incentives as the means to discipline regulated industries and fulfill the Commission's constitutional responsibilities.

The Commission puts that approach to use when it adopts the "new regulatory framework" for the telecommunications industry, and sets out to restructure California's natural gas industry. The Commission also attempts to advance this approach in the electric industry, as it refocuses on developing a methodology to determine the utility's long-run avoided cost. Once established, the methodology will guide the development of ISO4's replacement, final Standard Offer 4, or FSO4.[112] It will be FSO4 to which the utilities will turn when future demand outstrips surplus utility resources and the need to acquire additional electric services reemerges.

In 1986, the Commission adopts the "Iterative Cost-Effective Methodology; or ICEM, as the tool the state will use to establish the utilities' long run avoided cost. ICEM identifies the type, size and timing of the utility's most cost-effective resource addition. The price of the addition ICEM identifies represents the utility's long-run avoided cost, to which FSO4 contracts will be linked. The Commission establishes the Biennial Resource Plan Update as

112 See D.86-07-004.

the forum in which issues related to long run avoided cost and resource planning and acquisition generally will be addressed. The Update will take place every two years following the release of the Energy Commission's Electricity Report.

Two policies in particular distinguish the Commission's approach to FSO4 from the one taken for ISO4, and illustrate the Commission's policy shift toward a more market-based approach.

First, with FSO4 the Commission adopts a competitive auction format to govern acquisition. This approach differs in two significant ways from the mechanism used under ISO4, which relied on Commission-approved price forecasts as the means of determining the amount of QF service the utility would purchase: 1) The auction promises to limit the amount of service purchased by the utility to the amount of cost-effective utility capacity identified in the Update proceeding; and 2) it ensures that prices for energy and capacity will more closely reflect the competitive conditions prevailing in the market for services since the prices are linked directly to offers made by the bidder rather than Commission approved forecasts.

Second, the Commission adds to ISO4's competitive auction its preference for quantifying valuable attributes the different generation technologies offer but for which no market price is readily available. The Commission believes that the signal direct quantification sends the electric services market will more efficiently develop and deliver these benefits to consumers. The Commission initially identifies benefits related to the environment and to operational characteristics, such as dispatchability, as ripe for quantification.[113]

In 1990, the Legislature passes Assembly Bill 3995 requiring the Commission to place values on the costs and benefits of environmental impacts and explicitly consider those values in its resource procurement process. The Commission has values for air emissions in place

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113 See D.86-12-057.

by 1991.[114]

Both the concern over California's environmental quality and the interest in market-based regulatory solutions heighten as the 1980s draw to a close. These concerns spawn a new partnership between the states' utilities, the Commission, and California's environmental regulators. This partnership attempts to coordinate economic regulation and environmental policy with the goal of striking the appropriate balance between the need to reinvest in the state's energy infrastructure and provide low-cost energy services to the state's consumers. Decisionmakers look increasingly to market-based solutions to strike that balance.

Building on these new approaches, the Commission participates in the South Coast Air Quality Management District's effort to determine both the feasibility and the benefit of including Southern California Edison in an "emissions trading market." The market is designed to meet state and federal air quality laws limiting the release of harmful emissions. Dubbed "RECLAIM," the program abandons traditional command-and-control techniques in favor of market incentives, with the hope of substantially reducing the costs of achieving air quality goals in Southern California. At the same time, the Commission coordinates its actions with those of air quality regulators responsible for limiting emissions on PG&E's and SDG&E's system.

California, and the state's IOUs, face a growing number of environmental challenges. These recent efforts represent constructive first steps in the attempt to ensure those challenges are met successfully and efficiently. Past Commission environmental policies, and exemplary utility management, hold out promise for success in the future: In 1992, PG&E and SDG&E are listed in the "no risk" category for acid rain, while Edison is listed in the "low risk" category.

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114 See D.91-06-002.

CHAPTER IV

Who Decides: Markets, Government, or Both?

Despite the significant strides made in developing contracts tied to long run avoided cost, it isn't until 1992 that the utilities put the Commission's competitive auction tied to long-run avoided cost to use. Each of the state's three major investor-owned electric utilities participate in the solicitation. The utilities expect to request bids from independent providers in the first quarter of 1993.

At the same time, the Commission, interested parties, and the Legislature begin to reexamine a procurement process developed over the better part of a decade. Many question the wisdom and the practicality of attempting to simulate a market dynamic through a government-sponsored administrative process when the workings of the electric services market seem to outpace that process at every turn. They assert that the state would be better served if the Commission relied on markets, or command-and-control regulation, but not both. They insist that intrusive government planning and competitive markets are incompatible. It is this unfortunate hybrid, they claim, that currently governs the state's energy services sector.

Others question whether the process ought to require the work of two agencies--the Commission and the California Energy Commission. The CEC, for example, expresses concern over what it views as the Commission's "duplication" of the Energy Commission's planning process. The Energy Commission argues that there is no need for the Commission to review utility resource plans once the Energy Commission has issued recommendations in its Electricity Report.

Still others express concern about the public policy trend toward regulatory reliance on "free market economics." They point to the experience culled from deregulation of the savings and loan industry as evidence that traditional, command-and-control regulation is appropriate, preferable, and underutilized.

In September of 1992, the Commission announces its intent to "examine the conditions the electric industry currently confronts...and explore alternatives to the current regulatory approach..." in California.[115]

The First Steps Toward Transmission Access and Workable Competition in California.

Though the need for new resources wanes in the mid- and later years of the 1980s, the controversy surrounding QF access to transmission services on utility-owned transmission facilities mounts. In the mid-1980s, the Commission sets forth its policy governing the allocation of costs incurred by the utility when constructing electric transmission facilities to accommodate purchases from qualifying facilities.[116]

Toward the end of the decade, Commission policy evolves from the selected use of auctions, economic price signals, and other market mechanisms, to the broader pursuit of a workably competitive market for energy services.[117] The Commission pursues this policy recognizing that to reap the benefits of market solutions and greater competition requires more than the emergence of a vibrant, competitively-priced independent power industry. Indeed, as the Commission previously learned when constraints on PG&E's network nearly threatened the development of QFs in the early 1980s, consumers are unlikely to benefit from competitively priced services absent the means of getting those services to market. Getting those services to market, and hence establishing a workably competitive market, requires access to the electric transmission network.

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[115] See D.92-09-088.

[116] See D.85-09-058. Briefly, the policy states that the utility's customers will bear the costs if any utility "system benefits" result from the construction of the transmission facilities. If no system benefits can be identified, the QF bears the full costs of the facility added to the utility's transmission network.

[117] See D.92-04-045.

In 1988, the Commission formulates policy designed to guide access to utility transmission services for any qualifying facility located outside the purchasing utility's service area. The utilities argue that providing service to those QFs is likely to force the utility to forgo otherwise economic transactions, thus bringing harm to its native load customers. In response, the Commission requires the utility to demonstrate that harm will come to ratepayers or accept power from the QFs requesting service from outside the service area.

With the need for new utility resources on the horizon in 1990, the Commission initiates a comprehensive investigation to develop policies governing pricing and access to utility transmission service by nonutility generators.[118] The Commission chooses to focus first on developing policies for including transmission costs in the resource planning and acquisition process for the utilities it regulates. The Commission issues those guidelines in 1992 for inclusion in the utilities pending bid solicitations.[119] The Commission announces that the subsequent phase of the investigation will focus on transmission access between investor-owned and publicly-owned utilities.

Legislative and Congressional Actions Governing Electric Transmission Access

By 1991, both the Legislature and Congress show great interest in developing a long-term solution to what many view as political gridlock over electric transmission. Intending to facilitate the efficient operation and development of the state's electric transmission network, the California Assembly and Senate offer competing proposals to allow industry participants to form "voluntary transmission associations," or VTAs. The bills designate VTAs as a forum for transmission planning and development, coordinating pricing and access policies

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118 I.90-09-050.

119 D.92-09-078.

governing transmission service, and resolving transmission-related disputes.

Concurrent with legislative efforts underway in California, Congress proposes legislation to reform transmission regulation at the federal level.[120] Most notable in the legislation is the proposal to grant the FERC broad authority to mandate wholesale wheeling under certain conditions. The proposal is controversial, with the interested parties ultimately striking compromise language which the conference committee accepts. Having succeeded in reaching a compromise regarding wheeling authority for FERC, some parties then set their sights on crafting language the conferees could accept establishing "regional transmission groups," or "RTGs"--California's VTA cousin.

The California Legislature is unsuccessful in passing a new law governing electric transmission in 1992.[121] Generally, interested parties oppose the proposals on the grounds that one or the other of the competing bills places government either too close to, or too far from, the decisionmaking process governing the state's electric transmission network.

Nor does the National Energy Policy Act--approved by Congress and signed by the President in the Fall of 1992--include VTAs or RTGs. Like the debate over such groups in California, the discussion of RTGs at the federal level is contentious, though a significant number of interested parties manage to reach agreement. The passage of PUHCA reform will foster new entrants into an increasingly competitive generation market and will sharpen the focus on transmission reform. In November of 1992, however, FERC formally requests parties to comment on whether to pursue the RTG proposal under existing FERC authority.[122]

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120 Transmission reform is part of the broader federal legislative package known as "The National Energy Act of 1992."

121 The Legislature nonetheless states its clear intent to revisit the matter in hearings during the upcoming 1993 legislative session.

122 FERC. Request for Public Comment. Docket No. RM93-3-000, November 10, 1992.

Thus, combined with FERC's new authority to mandate wheeling, and increased interest in nongovernmental transmission groups at both the state and federal level, the issue of transmission access and pricing remains at the forefront of the regulatory process as 1993 begins.

The California Collaborative: Energy Efficiency Gets a Shot in the Arm

Despite the Commission's success in encouraging the utilities to "get more energy service from less" in lieu of simply maximizing sales volume, DSM funding first declines in 1985 then falls precipitously between 1986 and 1988. It isn't until 1989, when the Commission again initiates reform of traditional DSM funding, that interest in DSM investment regains prominence among utility managers.

Citing ample power plant capacity, and an abundance of cheap fuel to operate the plants, the utilities request and the Commission grants decreased rates of investment in energy efficiency during the 1985-1989 period.[123] At just under $55 million in 1988, the utilities' investment is less than one half of the approximately $125 million invested in 1984.

By 1989, surplus capacity wanes and California's pressing air quality problems grow. Fearful that the decline in utility DSM investment might leave efficiency programs beyond rehabilitation, the Commission convenes an *en banc* to reexamine the role of DSM in utility resource procurement.

At the *en banc*, the Commission initiates a statewide collaborative process. The collaborative approach is designed to bring interested parties together outside the adversarial atmosphere of the hearing room to draft a blueprint for revitalizing utility DSM activity in California. The Commission directs the group to make shareholder incentives one of the blueprint's key features.

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[123] Calwell, C.V. and Cavanah, R.C., The Decline of Conservation, p. 13.

The Collaborative stakeholders represent a wide array of interest groups, including consumers, utilities, environmentalists, and independent power producers. Their success is marked. In 1990, the California IOUs request and Commission approves significant increases in utility investment in DSM. By 1992, IOU investment exceeds $330 million, a 600% increase above the level of investment in 1988.

The utilities' renewed interest in energy efficiency is two-fold: First, ratepayers are better off when the utility invests in energy efficiency options that offer comparable or greater benefits than generation alternatives. Second, with Commission approval of shareholder earnings for DSM investment, utilities for the first time face a more balanced incentive when choosing between investments in supply and demand resources. After years of debate about the role of the utility in delivering energy services, the Commission's decision to allow shareholders to participate in the benefits attributable to energy savings redefines the role of the utility in California: Once the marketer of a single commodity--electrons--the utility role shifts to that of a service company, offering customers a wide range of energy services and technologies.[124]

With the intent of establishing a comprehensive vision of the utility's role in DSM, the Commission issues in 1991 a comprehensive set of proposed policies to ensure the efficient implementation of cost-effective utility DSM programs.[125] As part of its investigation and rulemaking, the Commission, with guidance from the Legislature, initiates a pilot utility bidding program for the acquisition of demand-side management services.[126] Information

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124 For an interesting vision of the utility as service company, see "An Energy Blueprint for the '90s," remarks of Richard A. Clarke, Chairman of the Board and Chief Executive Officer, PG&E, before the Commonwealth Club, San Francisco, California, May 1, 1992.

125 See R.91-08-003 and I.91-08-002, August 9, 1991.

126 Legislative direction comes in Senate Bill 539, now P.U. Code 747.1.

culled from these pilots will help the Commission assess the role of DSM in the context of its broader objective of achieving a workably competitive market for energy services. Consistent with legislative direction, the pilots include an "integrated bid," in which DSM programs compete directly with supply-side resources to serve the market. As the IOUs ready the competitive *acquisition* pilots for release, the Commission continues its parallel examination of methodologies designed to integrate supply and demand resources in resource *planning*. These methodologies, like the bidding pilots, attempt to assess demand and supply resources using a common set of least-cost planning principles. The task is daunting; and experts remain divided. At the Commission *en banc* convened to address all-source bidding, opinions are decidedly mixed.[127]

As 1993 Nears, the Challenges Facing the Nuclear Industry Continue

Despite the electric industry's efforts to move beyond the troubles brought on by the "nuclear experiment" of the 1950s, 1960s, and 1970s, utilities in the West announce in 1992 the early retirement of California's San Onofre Nuclear Generating Station #1 and Portland General Electric's Trojan nuclear facility. Both plants require significant capital investment to continue operating. Using its least-cost planning forum--the Update--the Commission does not find the investment required for the San Onofre facility to be cost-effective. Similar conclusions are reached in Oregon regarding Trojan.

In approving the request for early retirement jointly proposed by California's Division of Ratepayer Advocates, Edison, and SDG&E, the Commission also grants the settlement proposal's request to accelerate recovery of the utility's unamortized investment tied to SONGS 1.[128] Recovery is to span four years.

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127 See Transcript, November 9, 1992, Volume 58.

128 See D.92-08-036.

CHAPTER IV

News of SONGS #1 prompts economic, financial and environmental questions about other nuclear units in the state. Many wonder if SONGS #1 represents the first of many early retirements in California and across the country. Suggestions that San Onofre units #2 and #3 also require substantial capital investment to continue operating increase speculation that as much as 2,000 MWs of generating capacity may be removed from California's infrastructure.

Toward Utility Rate Normalization's request that the Commission revisit the settlement governing Diablo Canyon further adds to the uncertainty looming over the future of the state's nuclear generating capacity. By 1992, all three of the California's IOUs appear on at least one security analyst's "nuclear exposure" list.[129]

This period begins with fears escalating over capacity shortages due to difficulties the utilities face bringing their nuclear power plants on line. It ends with at least the potential for substantially increased capacity needs in the state due to the accelerated retirement of these same nuclear plants.

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129 "Electric Utility Credit Review" Mabon Securities Corporation, March 20, 1992, page xiii. In 1992, Edison's revenue requirement totals just over $7 billion. That portion tied to Edison investment in nuclear facilities is approximately $1.7 billion, or approximately 25% of the company's total revenue requirement.

CHAPTER VI

1993: IS TODAY'S REGULATION COMPATIBLE WITH THE PREVAILING INDUSTRY STRUCTURE?

Though the Commission's strategies succeed for the most part in managing challenges of the 1970s and 1980s, the majority of those strategies are less well suited to the challenges confronting the industry in 1993.

The state's continued emphasis on an interventionist regulatory approach, to which the past two decades have brought several balancing accounts and rate adjustment mechanisms, leaves the state with a complex and administratively burdensome apparatus. Moreover, attempts to tailor these policies and programs to an increasingly competitive electric services market have been outpaced by rapid changes within the industry.

A legacy of the previous decades is the current gap between utility average rates and the increasingly competitive cost of providing electric service. This gap reduces utility competitiveness and forces some customers to take advantage of less costly nonutility alternatives. Large consumers who are now providing goods and services in highly competitive global markets are increasingly sensitive to production costs. Those for whom electric service represents a significant portion of those costs are most apt to look elsewhere. Their departure from the system threatens to increase rates for utility customers who do not enjoy comparable options.

Years of fine tuning a sophisticated least-cost procurement process that attempts to predict "what the utility would do" further leaves the state with what many view as a lengthy, intrusive, and complex regulatory approach that no longer seems to mesh with a rapidly changing market for electric services. In response, at least one utility proposes to cease building new generation in its service territory. Another proposes extensive reform in an application requesting performance-based ratemaking in several areas of its operations. Many are surprised to hear calls for reform coming from an industry not traditionally characterized by requests for dramatic change.

Finally, while the Commission has enacted an innovative incentive mechanism for utility investments in energy efficiency, the array of incentives influencing utility decisions governing whether to build new generation, purchase power from others, or provide service more efficiently seems neither balanced, nor necessarily consistent with the pursuit of workable competition.

Nearly twenty years after the oil embargo and the passage of PURPA, the conditions facing the electric industry, and the structure of the industry itself differ markedly from those in place when the Commission developed the regulatory programs in use today. In 1993, there *is only limited compatibility between the regulatory tools the Commission uses to govern the electric industry and the current state of that industry.*

Cost-of-Service Regulation: Unintended Results

Cost-of-service regulation evolved for the most part in an era of stable or declining electric rates, increasing productivity, and steadily rising revenues.[130] But even during the prosperous years of the 1950s and 1960s, many believed--and many believe today--that cost-of-service regulation leaves the utility with incentives to perform in ways that diverge, albeit unintentionally, from Commission and state policy goals.[131] With the changes made to meet the challenges of the 1970s and 1980s, many assert that the number of undesirable incentives has increased.

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130 Many believe that, in contrast to conclusions drawn by a large number of analysts, what this report refers to as the "Glory Days" of the utility industry, represents more of an exception to the rule, than the rule itself. They point to the fact that economic trends in the utility industry are not unlike those experienced in the U.S. economy over the past several decades. They note specifically that at the same time productivity within the utility industry leveled off (some would say declined), productivity at the national level--while still impressive--has declined steadily, falling approximately three and one-half percent in the 1950s to about one and one-quarter percent in the 1980s. For this reason, at least one leading expert concludes that "...the 1950s and 1960s are not the 'norm' to which regulators and utilities should look for lessons." (Stalon, Charles, "Whither the Regulatory Compact," presented to a seminar on the regulatory compact sponsored by the California Foundation on the Environment and the Economy. July, 1992.)

131 Some economists attribute the disincentives discussed below to what they view as cost-of-service regulation's emphasis on the pursuit of fairness, which they argue comes at the expense of economic efficiency. Critiques of cost-of-service regulation may be found in Phillips, Charles, The Regulation of Public Utilities: Theory and Practice, part VI; Kahn, Alfred, The Economics of Regulation: Principles and Institution; FERC, NOPR "Regulation Governing Independent Power Producers": Docket RM88-4-000 p. 9-29; NRRI, A Review of FERC's Technical Reports on Incentive Regulation. See also, Joskow, op. cit., pp 19-21.

CHAPTER VI

The Potential for Inefficient Investment

Perhaps the most troublesome of these incentives is the unbalanced profit motive underlying cost-of-service regulation. Recently described by one utility CEO as an approach that "spur[s] utilities to focus on tonnage of money invested," cost-of-service regulation has long been viewed by critics as an impediment to efficient investment and operation in the regulated utility industry.[132]

Many argue that by tying utility rewards to the amount of investment dollars directed toward plant construction, cost-of-service regulation is chiefly responsible for the utility's historical reluctance to invest in energy efficiency improvements and cost-effective purchases from independent power producers.[133]

Critics of the approach also point to what they view as an im balance in risk-sharing brought on by cost-of-service regulation. This imbalance, they argue, arises from the tendency to place market risks with consumers, particularly risks related to technological change. These critics conclude that unbalanced risk sharing reinforces the inclination toward inefficient investment and planning.[134]

The general rate case is another component of cost-of-service regulation to which critics point as a source of inefficiency. This criticism comes despite recognition that cost-of-service regulation provides a positive incentive to operate efficiently. Between rate cases

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[132] Remarks of Thomas A. Page, Wall Street Journal, October 19, 1992.

[133] This bias toward capital investment is known as the Averch-Johnson effect. For a detailed discussion see Friedman L.S., Microeconomic Policy Analysis, McGraw-Hill, 1984, pp 578-581, Phillips, The Regulation of Public Utilities, p. 809-810 and Kahn, The Economics of Regulation. pp. 47-59.

[134] Even the critics of cost-of-service regulation recognize that Commission oversight, including prudence reviews, mitigates--in theory if not in practice--the potential for inefficient investment and planning.

the utility retains any revenues generated by outperforming the assumptions and forecasts approved in the general rate case. Many assert this incentive is a weak one, however. Due to the short period between rate cases--three years in California--the utility enjoys the benefits of its efficient performance only until the next rate case, at which time cost savings are identified and the revenue requirement lowered commensurately. Further, detractors of cost-of-service regulation allege that the GRC's positive incentive is overshadowed by the still stronger incentive to inflate assumptions and forecasts for financial gain. If left unchecked by the Commission, this incentive results in increased costs to consumers.[135] In addition, the Commission resources required to counter utility "gaming" of forecasts raises administrative costs, increasing costs to consumers.

The Problem of Balancing Accounts and Rate Adjustment Mechanisms

Critics maintain that balancing accounts and rate adjustment mechanisms represent a departure from the historical means used to uphold the traditional regulatory compact. They allege that these recent additions to the process bring with them their own unique set of deficiencies, and exacerbate the disincentives inherent in cost-of-service regulation described above.[136]

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135 The practical inability of a regulatory body, endowed with limited resources, to scrutinize the many complexities of utility operations has led many to question whether the most diligent of regulators could ever hope to adequately oversee the utility. See for example, Friedman, L. S., op. cit., p. 581.

136 Risk, Return and Ratemaking, op. cit., describes these mechanisms and also provides a detailed critique of the implications of these mechanisms for the regulatory process and the operations of the regulated electric utility.

CHAPTER VI

The Commission's decision to create balancing accounts and rate adjustment mechanisms came in direct response to a period of skyrocketing utility costs and volatile fuel and financial markets. The Commission put these mechanisms in place to insulate the utility from the financial risks and uncertainties rampant in the 1970s and 1980s--risks and uncertainties with which the industry (and the Commission) had limited, if any, experience prior to the 1973 Arab Oil Embargo.[137] While these mechanisms have been largely successful in improving and maintaining the financial health of California utilities, they require expensive and time consuming regulatory proceedings. But as 1993 approaches, utility management appears to have gradually adapted to the effects of previously escalating costs. In addition, the volatile markets of two decades ago are relatively stable, and that stability is expected to persist in the future.[138]

Costly regulatory procedures, though never welcome, are particularly burdensome in troubled economic times. And with the majority of the balancing accounts and rate mechanisms still in place today, the utilities, the Commission, and ultimately the state's consumers, bear the burden of regulatory tools established to address conditions that no longer persist, and arguably are not expected to return soon. Additionally, many question whether these accounts have thrown the traditional risk/reward relationship governing the industry out of balance. They argue that utilities enjoy stable or increasing returns while balancing accounts continue to shift risk away from the utility to consumers for costs associated with, for example, fuel and purchase power--risks historically shouldered by the utility under the traditional regulatory compact. In 1991, approximately 75 cents of every dollar of Edison and SDG&E revenues were fully subject to balancing accounts and rate

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137 In addition, the majority of these mechanisms were ostensibly added to the process with the hope of reducing complexity, adversarial behavior and gaming.

138 See Chapter VII.

adjustment mechanisms. For PG&E due largely to the performance-based approach tied to the Diablo Canyon facility, approximately 50 cents of every dollar of revenue is subject to these same accounts.[139]

The Problem of Mounting Reasonableness Reviews

The increased number and frequency of reasonableness, or prudence, reviews that must accompany the current array of balancing accounts and adjustment mechanisms further add to the complexity and cost of the regulatory process. Those costs are passed on to the consumers of the state's electric services. In addition to the added consumer costs, and the increased administrative burden, prudence reviews add to utility management's perception of risk and uncertainty.

For example, the Commission's *ex post* review of utility decisions sometimes occurs after Commission policy and the conditions initially prompting utility action have changed. Thus, although the decisionmaking process governing prudence reviews explicitly attempts to avoid engaging in judgment based on hindsight, utility behavior is nonetheless influenced by the prospect of regulators "second-guessing" events that may have transpired years before.

The prudence review also poses one-sided, or "asymmetric" financial consequences for the utility. The utility bears the full cost of expenditures the Commission finds "imprudent," yet it does not enjoy the benefit of *prudent* decisions whose outcomes exceed initial expectations. Those benefits flow instead directly back to consumers. This asymmetric regulatory mechanism may foster utility behavior that conflicts with the state's interest. For example, liable for the costs associated with "imprudent" decisions, and unable to participate in the rewards of "prudent" ones, the utility may manage risk by avoiding what

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139 From data compiled with the assistance of the Commission's Division of Ratepayer Advocates.

might otherwise be cost-effective investments.[140]

Market Forces Increasingly Shape the Electric Industry

In addition to the shortcomings discussed above, cost-of-service regulation as practiced in 1993 appears troublesome when viewed in light of prevailing market conditions and the changing structure of the electric industry. Cost-of-service regulation came of age in an era when the monopoly character of electric utilities was dominant. Maintaining the monopoly franchise under the traditional regulatory compact was made easier when scale economies in the industry kept prices low and the pace and magnitude of technological advancement remained moderate and predictable.

This environment fostered a secure monopoly position for the utility and created considerable economic obstacles for anyone attempting to enter the electric services market. As a result, consumers historically enjoyed little, if any, influence over the source of their electric service, or over the type of service offered. The utility provided consumers with safe, reliable service, and practically speaking, was the sole provider. By contrast, consumers in 1993, particularly large consumers, enjoy increased influence in the electric services market, which in turn has had an effect on the structure of the industry. As is discussed further in this chapter, that influence is likely to increase in both scope and magnitude.

Consumers Enjoy Greater Market Influence

Under the traditional vertically integrated structure, consumers exercised indirect influence over the industry--from services provided to prices levied--through this Commission and elected officials. Traditionally, that influence was arguably diffuse, and felt predominately during difficult times, when upward pressure on utility prices became acute.[141] The

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140 The Commission's ability to identify and hold the utility accountable for each and every cost-effective investment is, of course, severely limited.

141 During 1981 for example, both electric and gas rates soared as a result of a number of

monopoly utility, on the other hand, held almost exclusive and *direct* sway over the type of electric services offered. With effectively nowhere to turn for services other than the regulated monopoly, consumers had little negotiating power and settled with the bundled electric service--generation, transmission, and distribution--offered by the utility. While opinions vary, evidence suggests that the system worked reasonably well for decades. (See Chapter III.)

However, the events of the 1970s and 1980s altered the balance of market influence between the monopoly provider and consumers. This "realignment" helped fuel the restructuring of the utility industry. Several forces combined to foster the restructuring; a few key events, discussed in detail in previous chapters, are summarized here.

First, rapidly increasing utility prices prompted the federal government to ease entry into the generation market for cogeneration and renewable technologies. The subsequent passage of PURPA, this Commission's efforts to foster the QF industry, and high oil prices lowered existing barriers to entry and led to rapid advancement of renewable electric and cogeneration technologies.

Second, federal deregulation of natural gas prices and policies designed to foster competition in the natural gas industry, coupled with deteriorating air quality, accelerated the development of cleaner, more efficient natural gas-fired generation technologies.

Finally, state and federal energy efficiency policies initiated in the 1970s accelerated development of demand-side management technologies and the energy service companies (ESCOs) that today offer services throughout the country.

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factors, including rising oil prices and passage of the Natural Gas Policy Act. Despite Commission attempts to shield residential customers from these increases, rising rates led to what became know as a residential "ratepayer revolt" in the state, prompting the Legislature to increase its focus on utility expenses. For a discussion of events during this time see Barkovich, B.R., Regulatory Interventionism in the Utility Industry: Fairness, Efficiency and the Pursuit of Energy Conservation, Quorum Books, 1989. p. 79-80.

CHAPTER VI

With technological improvement and utility rates on the rise, unregulated self-generation and demand-side management providers thus began to compete aggressively for utility market share.[142] Under these emerging competitive conditions, large electric consumers--for whom electric bills make up a significant portion of business expenses--no longer relied exclusively on the utility for electric service. They could reduce consumption and lower costs by turning to nonutility providers of DSM services, through the purchase of self-generation or cogeneration services, or they could bypass the utility system altogether. Both options pose considerable financial threat to the utility, and both threats continue.

Though ERAM insulates utility revenues from the risk of sales fluctuations, including loss of sales due to bypass, utilities are not immune from the effects felt when customers reduce consumption or leave the utility system. As sales drop due to improved efficiency, or customers depart from the system for less expensive alternatives, rates charged to the remaining utility customers must rise to recover the utility's fixed costs, prompting still greater numbers to "shop around." Captive, generally residential, customers for whom comparable competitive alternatives do not readily exist, are left "holding the bill," both in terms of rising rates and stranded utility investment.[143]

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142 For one CEO's perspective on the extent to which "[a]dvances in technology have left utilities without their 'natural' monopoly status...," see Bayless, C.E., "Natural Monopolies: Accepting the Truth," Public Utilities Fortnightly, February 1, 1992.

143 "Economic" bypass is generally encouraged since doing so increases the efficiency with which society makes use of its resources. A considerable portion of the then Policy and Planning Division's 1986 report, Risk, Return and Ratemaking focuses on the problem of customer bypass. The report cites the insulating effect of balancing accounts and rate adjustment mechanisms as a key contributor to the threat of bypass, asserting both provide the utility with disincentives 1) to keep costs (and rates) down, and 2) to compete aggressively for market share through better communication with customers.

CHAPTER VI

Signs of a Rapidly Changing Electric Industry

Consumers, particularly large ones, now enjoy considerable influence within the industry. Correspondingly, the ability of the utility and the regulator to preserve the monopoly franchise has lessened.

Increasingly fearful of losing customer load and the contribution to total costs this load represents, the utility now competes for a significant portion of its market share, often negotiating directly with large consumers over price and services delivered. For their part, unregulated service providers promising lower bills and economic productivity also focus on this lucrative segment of what was once protected utility turf. Consumers are no longer confined to bundled utility service. Instead they exert considerable influence over the mix of services delivered. Greater consumer sophistication and the breadth of choice enjoyed by predominately large consumers force utility and nonutility providers alike to "unbundle" services, crafted to meet the specific requirements of the individual customer.

Despite the legal and regulatory obstacles to entry that persist in many retail electric markets, unregulated providers enjoy market opportunities that few imagined possible prior to 1978. Competitive pressures threaten to erode utility market share, further emphasizing the importance of efficiently delivered, customized services. The threat to the utility becomes increasingly acute as the gap widens between utility *rates* and the competitive *cost* of alternatives to which customers may turn.[144] The Persistence of the "Rate-Cost" Gap

The first significant threat of utility bypass due to the rate-cost gap took place during the 1980's. Over time the gap has varied depending on fuel prices, interest and inflation rates,

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[144] Phillip O'Conner, Chairman and President of Palmer Bellevue Corporation, discussed the problems this gap could bring to the electric industry as far back as 1987 in his paper titled, "Electricity--The Final Monopoly?," delivered before the Commonwealth Club, on February 25, 1987. Paul Joskow has more recently written about the issue, op. cit., pp. 29-33.

the level and timing of utility capital investment, and many other factors. Now, with competitors' costs dropping and the prospect of accelerating competition discussed further in Chapter VII, the challenges facing the states IOU's are on the rise.

The Gap and Increasingly Efficient Alternatives

In 1993, the premium on low-cost energy services continues to mount. With increased regional and global competition, even small differences in energy bills can have significant consequences for the competitiveness of California's economy. Businesses are increasingly indifferent to whether the lowest-cost service comes from the utility or a nonutility provider. As technological improvements add to the number of low-cost options available, any widening of the gap is apt to drive consumers--particularly large ones--off the utility system, leaving those without choice to shoulder the utility's fixed costs, and the cost of any stranded investment.

The Gap and Cost-of-Service Regulation

Some observers claim the gap is the direct result of cost-of-service regulation. First, they argue the gap stems from the utility's incentive to increase earnings by inflating cost estimates and other projections in the regulatory process. In addition they point to balancing accounts, which shelter the utilities from risk thus removing the incentive to contain expenses; the tendency of cost-of-service regulation to make utilities very "process-oriented and bureaucratic"[145]; returns on equity that have historically outpaced returns earned by unregulated firms and which raise utility costs over that of competitors; and finally, the incentive offered by cost-of-service regulation to overbuild the utility system beyond the efficient level.

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145 Page, Thomas, Wall Street Journal, op. cit.

Those who credit cost-of-service regulation with creating and maintaining the gap also believe that the Commission's attention to the problem is inadequate. They argue that since the utility's resources are vast, the Commission can not hope to successfully police every utility decision without further adding to the costs of cost-of-service regulation. They further claim that the effort to do so in California has left the state with complex, costly, and administratively burdensome regulatory processes which rely disproportionately on micromanagement of the industry.

Still others assert that a long tradition of cost-of-service regulation and monopoly control of the industry leaves the utility ill-equipped to operate in an increasingly competitive environment. In the past, this inability posed few threats, since the utility enjoyed a strong monopoly position in the industry. In 1993, the utility is both willing and searching for ways to compete; and competitiveness represents one of the utility's principal strategies for the future.

The Gap, Asymmetric Costs and the "Level Playing Field"

Some claim the gap may also be attributed to factors unrelated to competition from nonutility generators and the disincentives related to cost-of-service regulation. They argue instead that independent providers escape many of the costs imposed on the regulated utility, and that this difference accounts for the gap and the competitive disadvantage facing the utilities.

For example, under the terms of the regulatory compac t, only the utility must provide nondiscriminatory service on demand. Unregulated providers may choose to whom they provide service, which, some argue, provides a greater opportunity to manage costs and remain competitive. In addition to the costs attributable to the utility's enduring duty to serve, utilities and others attribute the gap to costs imposed by regulatory and legislative mandates. These are costs to which unregulated providers are not subject, and from which businesses opting to self generate are freed once they leave the utility system. These costs include subsidies for low-income consumers (Low Income Rate Assistance, or LIRA); subsidized demand-side management targeted at low-income individuals known as Direct Assistance programs; administration of the Women and Minority Business and Disabled Veterans programs; operating regional utility offices where customers can pay their bills; rates designed to encourage economic and agricultural development; providing low emission (natural gas and electric) vehicle programs; and other services the utility provides its customers.

They point as well to Commission oversight of the utility business, citing Commission-approved capital structure as an example of a cost imposed on a regulated utility that widens the gap. Equity-rich, Commission-determined utility capital structures, they argue, increase the utility's cost of raising funds relative to unregulated providers, whose ability to leverage their equity with higher levels of debt is disciplined by the financial markets, and only indirectly by regulators.[146]

Recently a great deal of attention has been paid to Commission policy requiring the utility to assign monetary values to air emissions for the purposes of utility resource planning and acquisition.[147] Since the code applies solely to the state's investor-owned utilities, many fear that these costs will only widen the rate-cost gap, further hindering utility efforts to enhance its competitive position and retain market share.

The utilities acknowledge the importance of government-imposed programs, and though observers cite room for improvement, the companies generally perform well in these

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146 See, for example, Swidler, Joseph, "An Unthinkably Horrible Situation," Public Utilities Fortnightly, September 15, 1991, and McClure, James A., "Independent Power: Future or Failure," Public Utilities Fortnightly, December 15, 1991. For a rebuttal, see, Naill, R.F. and Dudley, W.C., "Challenging the Critics of Independent Power," Public Utilities Fortnightly, January 15, 1992.

147 Section (c) of Public Utilities Code 701.1 requires that, "[i]n calculating the cost effectiveness of energy resources the Commission shall include a value for any costs and benefits to the environment, including air quality."

areas. However, they also question whether the costs associated with these programs create a fundamental incompatibility with the Commission's pursuit of a workably competitive generation market for California, asking if the "level playing field" hasn't been skewed to disadvantage the utility.

For their part, nonutility providers believe many aspects of the current regulatory regime places competitive advantage with the utility. They point to balancing accounts, which insulate the utility from risks unregulated businesses routinely must confront. Moreover, if regulatory, legislative, economic, or financial conditions alter market dynamics, there is no regulatory body from whom the nonutility provider can seek relief. Nor does the Commission grant nonutility providers a return on investment.

In all likelihood, each of the areas discussed above, whether it be technological innovation and lowered market barriers, the shortcomings of cost-of-service regulation, or utility-specific costs, contribute in some way to the gap between utility prices and the cost of competitive alternatives. But it is perhaps most important to recognize that the gap exists, and with it, the growing pressure for many California businesses to look beyond the utility for electric service, exacerbating the problem of uneconomic bypass.

CHAPTER VI

Some Implications of the Gap

The rate-cost gap left few uneasy when entry to the utility industry was difficult, and the pace of technological innovation moderate and predictable. In 1993 those conditions no longer hold. Consequently, if the Commission's vision for the electric industry includes vigorous competition, with the utility as an active participant, the implications of this gap, and the elusive level playing field, require greater scrutiny. One only has to look to the telecommunications and natural gas industries for comparable pressures and tensions, the result of which led to dramatic restructuring of both industries.

Absent such scrutiny, the Commission may find it difficult to prevent the electric industry from devolving into a bifurcated industry structure: one in which customers with the means and circumstances are able to take advantage of competitive alternatives, while those less endowed find themselves, absent heavy Commission intervention, less able to benefit from the technological advancement and market opportunities emerging in the electric industry.

But even with rigorous Commission oversight, the gap could increase if substantial numbers of customers exit the utility system. These large customers, for whom the system was partially constructed and to whom the utility expected to provide service, represent significant contributors to the cost of maintaining the infrastructure necessary to serve all customers. As the number of customers on the utility system diminishes, so too may the amount of utility investment dollars available to ensure that all Californians benefit.

Government Resource Planning and Increased Competition

The shortcomings of cost-of-service regulation come sharply into focus when viewed through the lens of California's evolving electric industry structure. Like balancing accounts, which were valuable tools during more volatile years, California's resource procurement process is better suited to a previous era. It too merits reexamination in 1993.

CHAPTER VI

The reasons prompting the Commission to assume the role of *partner* in utility resource planning, and to *foster* a competitive independent power industry, no longer persist. Saddled with the fallout of an energy crisis, a utility infrastructure whose system relied heavily on aging, relatively inefficient oil plants, and unfavorable economic and financial conditions, the Commission believed that allowing "small power producers to enter into direct competition with utility generation" would spawn a new and efficient supply of generation for the state.[148]

During this period, the Commission sought new supply opportunities to increase system reliability through improved reserve margins and a diversified energy mix. Competition was also expected to displace less efficient utility resources, thus lowering costs to consumers.[149]

Mitigating the effects of the Energy Crisis and introducing competition into an industry dominated by vertically integrated monopolies required the Commission to take an active role in utility management generally, and utility resource procurement specifically. This has led to the complex and costly utility procurement process on which the state currently relies. Such government planning seems ill-suited to California's changing electric industry in 1993.[150]

Emerging Markets Outpace Government Planning

Prior to the Energy Crisis, utility services changed only gradually, as the regulatory process acted as "gatekeeper" through which technological advances, and entrepreneurs

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148 See "Commission Report and Request for Comments," in A.82-04-044, A.82-04-040, and A.82-04-047, p.1.

149 Ibid.

150 For a rigorous analysis of the history of "interventionist" regulation in California, see Barkovich, B.R., <u>Regulatory Interventionism in the Utility Industry</u>.

pioneering new services, found their way to the regulated electric industry. In 1993, product development is rapid and dynamic.

Despite changes in the industry, the state's planning and acquisition process as practiced by the CEC and the Commission has not evolved commensurately.[151] Increasingly, the customer's unique circumstances, and *competition* among suppliers, drive product development. Yet the state relies on an *administrative process* which projects the date the utility ought to build new generation, as well as the exact type and size of that addition.

This administrative approach attempts to predict the most cost-effective addition to the utility system, even though, as one industry expert recently commented, "The main thing we know about [forecasts] is they are all wrong..."[152] The Commission has attempted to account for this uncertainty by allowing the utilities to present scenarios or alternatives to CEC-adopted utility resource plans before the CPUC. Moreover, the Commission has chosen not to subject to competitive auction the total amount of cost-effective MWs identified in the Update.[153] But as consumer choice and competitive markets play a greater role in determining services, it is doubtful that a government planning process can successfully match the state's resource requirements with the services sought by consumers. A single set of expectations--in this case a utility resource plan--rarely approximates market-driven

151 The process, a joint endeavor of the CEC's and the Commission, includes the CEC's Electricity Report and the Commission's Biennial Resource Plan Update Proceeding, or the Update. For the purposes of this report, the term Update is used to encompass the activities of both Commissions.

152 Comments of Dr. Scott Cauchois at an *en banc* hearing of the Commission, March 31, 1992, from pp 5163-5164 of the proceeding's transcript. Dr. Cauchois illustrated his claim explaining that during his tenure at the California Energy Commission in the early 1980s, the CEC predicted oil prices in the early 1990s would reach $120 per barrel. The average price in 1992 was approximately $20 per barrel.

153 See D.92-04-045.

outcomes.

Still, some argue that the IOUs' *wholesale* market, which the state's procurement process governs, differs significantly from the "market" for *retail* services currently enjoyed by a limited number of large consumers. They assert that the utility's market power is sufficiently strong and their interest in the wholesale market is so pervasive that, if left unchecked by regulators, utilities will impede the development of a competitive wholesale market.

Supporting the need for a broad government role in electric utility resource procurement, they point to the utility's monopoly over transmission and distribution; the utility's market power as a major buyer of wholesale service in the generation market; the strong incentive cost-of-service regulation provides for the utility to build rather than purchase power (for which no comparable return is earned); and the problems the Commission has experienced overseeing transactions between the utility and its affiliate. Proponents of this view argue that the differences between the wholesale and retail markets support continued reliance on extensive regulatory oversight of utility procurement.

There are few who question the need to mitigate the utility's monopoly and monopsony power if the Commission wishes to establish a workably competitive electric services market. Many recognize the bias toward utility construction inherent in cost-of-service regulation, and the special concerns affiliates and self-dealing pose for the industry. There is less evidence, however, that a process by which the state mandates the precise type, size and timing of utility resource acquisitions is required in 1993 to mitigate these concerns.

The choices offered by the wholesale market may differ markedly from the utility-specific options identified in formal regulatory proceedings. In fact, auctions for independent power performed throughout the country routinely yield responses that exceed the amount of MW solicited by a factor of ten, or more, indicating that a vibrant market currently exists.

This level of response underscores the need to question the relevance of a government-directed process that attempts to mimic utility behavior.

Changes in the electric services market have outpaced Commission policy, and the programs intended to carry out that policy. The Commission's portfolio of regulatory mechanisms relies on an outgrowth of cost-of-service regulation for its resource procurement program. Neither the Update nor cost-of-service regulatory programs may be consistent with the market-based policies embraced by the Commission, or with the pace of market-driven change in the electric industry. As such, both are due for reexamination.

In addition, the Update is ill-suited to the rapid change California is likely to experience, and the range of industry structures those changes might spawn. The current approach represents a hybrid, which attempts to "harness" market forces within a cost-of-service framework developed when vertically integrated monopolies prevailed in the industry. Experience in the telecommunications and natural gas industries suggests that the hybrid of command-and-control regulation and market-driven approaches is difficult to sustain. In 1993, the task facing the Commission is to better synchronize the Commission's regulatory programs and strategies with the dynamic electric services industry.

In Search of Alternative Regulatory Approaches: The Compact Revisited

The increasing complexity of regulatory processes has prompted this Commission, commissions across the country, and the federal government to explore alternatives to litigation and alternative regulatory approaches. These alternatives often lead to modifying the traditional regulatory compact between utilities, consumers, and regulators, as well as the means for upholding it.[154]

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154 See, for example, Federal Energy Regulatory Commission, Policy Statement on Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities (Washington D.C.: March 13, 1992) Docket No., P. (92-1-000).

CHAPTER VI

Alternative dispute resolution, or ADR, emphasizes mediation and consensus-building to advance the state's interest. The California DSM Collaborative process initiated by this Commission in 1989 illustrates that, with clearly articulated policy guidance, ADR can bring expeditious, less costly, and responsible decisionmaking to the regulatory process. The Commission's recently issued decision in the San Diego Gas and Electric general rate case provides additional guidance on all-party settlement, thus further empowering interested parties to resolve issues that might otherwise have required litigation.[155]

Most alternative regulatory approaches base utility earnings on *performance* rather than "tonnage of money invested".[156] Notable among these are the Commission's new regulatory framework governing the telecommunications industry, and its more recent proposal to reform transportation pricing for the noncore sector of the natural gas industry.[157] Each reflects the Commission's belief that modifications may be appropriate to both the regulatory compact and the *means* the Commission uses to carry out its duties and obligations. Most changes have come, however, in the means employed to uphold the compact rather than to the compact's fundamental tenets.

The telecommunications industry has seen significant changes to the regulatory compact and Commission programs designed to uphold it. First, the utility cost its exclusive retail franchise as part of the court-imposed divestiture. Despite this loss, however, the utility retained its responsibility under the new Regulatory Framework of ensuring nondiscriminatory service. The framework also provides the utility with considerable flexibility to compete in the market for telecommunications services. Finally, it bases the utility's earning on its

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155 See D. 92-12-019.

156 Page, Thomas, Wall Street Journal, op. cit.

157 OIR 92-12-016, OII 92-12-017.

performance, which encourages efficiency.

In natural gas, the Commission has also modified both the compact and the means of upholding it. Specific customers within the utility's service territory can purchase gas from nonutility providers. Granting customers the ability to choose nonutility gas supplies removes the utility's exclusive franchise granted under the traditional regulatory compact. In December of 1992, the Commission further modified the means to uphold the compact by putting the utilities at greater risk for recovering revenues and earning a fair return from noncore natural gas throughput. This change moves the gas utilities closer to performance-based regulation for their noncore business.

With the adopted settlement governing cost recovery for PG&E's Diablo Canyon Nuclear Generating Station and shareholder incentives for utility investments in DSM, the Commission has also initiated--albeit to an arguably lesser extent--performance-based regulation in the electric industry. Each mechanism departs from the traditional means employed by the Commission to fulfill its obligations under the regulatory compact.

The Commission's performance-based approach to utility DSM investment is a first step toward eliminating the bias between the utility's incentive to build and its incentive to invest in efficiency. Despite this move, the cost-plus treatment of utility investment in plant and equipment and the performance-based treatment of DSM investment is likely to continue to bias utility decisions governing investment dollars.

Moreover, no comparable mechanism exists that provides the utility an incentive to perform well in power purchase activities. Three wholly different mechanisms governing investment in generation, energy efficiency, and purchased power translates to an imbalance in regulatory incentives. That imbalance is likely to lead to less than optimal utility operation and investment decisions. These differences in utility profit motive are also ripe for reexamination.

Some argue against attempts to alter regulation in the attempt to balance incentives faced by the utility, preferring instead a process in which *the Commission* determines the efficient mix of utility generation, energy efficiency, and power purchases. However, the changes, challenges and competitive pressures taking place in today's electric industry, and those likely to emerge in future, may require alternative, performance-based regulatory approaches--approaches that ensure appropriate oversight with less resources, and that better align regulatory incentives with the state's goals.

Yet the pressure for regulatory reform is likely to increase. For example, San Diego Gas and Electric Company, in an effort to respond to a more competitive environment while retaining its place as the low cost provider of electric service in California, has proposed performance-based ratemaking for certain elements of the companies operations. An official of the company cites a desire to have regulators emphasize "..rewarding companies for their performance in competitive markets..." as the motive for their initiative.[158]

Also responding to the current regulatory approach, PG&E has suggested that the company would no longer construct plants to meet growth in its service area in return for increased flexibility to negotiate directly with generation providers.[159] These requests for regulatory innovation from an industry alleged to resist reform have taken many observers off guard.

In light of the challenges the industry currently faces, the following chapter explores the kinds of pressures that may influence the future of the electric services industry and likely hasten the changes already underway.

Finally, Chapter VIII examines a range of regulatory approaches the Commission might explore with the intent of providing a more optimal balance of incentives, risks, and

158 "SDG&E Proposal to Tie Profit to Performance Could Lower Rates," Los Angeles Times, October, 20, 1992, p. D1.

159 Transcripts from Commission en banc, November 9, 1992, op. cit., p. 6081.

rewards among the industry's participants. Key to selecting regulatory tools appropriate to this industry are clearly articulated goals to guide change, as well as the criteria necessary to assess the success of the programs designed to achieve those goals. Such criteria are also discussed in Chapter VIII.

CHAPTER VII

WHAT THE FUTURE HOLDS FOR THE ELECTRIC INDUSTRY

Any comprehensive examination of California's electric industry, and Commission programs governing the industry, must include a look to the future as well as to the past. Trends the industry and this Commission are likely to face in the future will hasten the structural changes already underway.

Broadly grouped, the trends expected to propel changes in the industry are linked to economic and technological forces; legislative and regulatory initiatives; and increased efforts to better include environmental considerations in private business decisions. When combined, these trends will increase the pressure on decisionmakers to facilitate the ability of customers--or certain classes of customers--to take advantage of competitively-priced alternatives. Indeed, customers for whom choice among service providers offers significant economic benefit have and will continue to contribute to that pressure. In short this study agrees with an ever-increasing number of industry experts who believe the principal issue facing the electric industry is not whether customers will be allowed greater choice, but when.

As continues to be the case in the telecommunications and natural gas industries, fundamental changes in market structure simultaneously pose threats and opportunities for this Commission, the state's utilities, nonutility service providers, and the state's consumers. Similar consequences can be expected in the electric industry. In both the telecommunications and natural gas industries, the Commission sought to mitigate the threats and exploit the opportunities of those changes through innovative regulatory approaches. Those approaches rely for the most part on modifications to the means used to uphold the regulatory compact, and to a more limited though significant degree, changes to the compact itself. But in each case, the Commission's core responsibilities under the state Constitution, which forms the foundation of California's regulatory compact, remain intact.

The Economic Outlook

The economy occupies the top spot on the business and public policy agenda across the country and is likely to remain high on the list for the foreseeable future. This is particularly so in California, which, once considered "recession proof," now finds itself languishing in the worst economic downturn since the Great Depression, with no signs of improvement in sight.[160]

Corporate downsizing and restructuring are increasingly common in the state and throughout the country; and firms are turning to writedowns with greater frequency.

California's unemployment rate exceeds ten percent--higher than any other state in the nation--a rate the state has not experienced since the recession of the early 1980s. Analysts primarily attribute the dramatic rise in the state's jobless rate to a severe downturn in the construction industry, defense-related cut-backs in response to the end of the Cold War, and dramatic decreases in wholesale and retail sales[161].

Added to these concerns is the fear that business flight from the state is fueling the loss of jobs. And while some studies assert that only 5% of the state's job losses can be reliably linked to business flight[162], and "[e]vidence about firms leaving the state numerically small and elusive,"[163] many view the threat as real and urge decisionmakers to include it in future planning.

California's economic crisis continues to dramatically reduce the State's fiscal resources, as tax receipts dwindle and demands on government services increase. Faced with a second straight year of severe budget shortfalls, the State's fiscal problems are

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160 California comprises 12% of the nation's population, 11% of its jobs, and 13% of its personal income. The Los Angeles and Bay Area ports handle nearly 17% of U.S. exports and 20% of imports. Sixteen percent of U.S. exports are manufactured in California, and its per capita real personal income has been consistently higher than the U.S. average. Source: "Pre-Election Economic Outlook 1992: Pacific Gas and Electric Company", October 1, 1992, p. 10.

161 An astonishing 85% of these job losses occurred in 7 counties in Southern California. Los Angeles County accounted for 60% of total job losses in 1991. Ibid., p. 13.

162 Ibid., p. 11.

163 "The Outlook for the California Economy" Center for Continuing Study of the California Economy, May, 1992, p. 1.

expected to continue.[164] In light of California's lingering economic and fiscal crisis, State spending at every level will receive close scrutiny, placing even greater emphasis on efficiency of government operations. As the Governor's Council on Competitiveness clearly points out, the scope and magnitude of the administrative costs of governing can directly influence the state's economic and fiscal health.[165]

Unfortunately, signs of near-term economic improvement are elusive. Most evidence suggests that, like other state's and nations before it, California's economy is in the midst of significant structural change. As a result of these changes, the state's economy is expected to grow less than it did during the previous decade;[166] and recovery in California is expected to lag behind that of the rest of the nation.[167]

In sum, the near-term outlook points to a sustained period of sluggish economic growth and diminishing government resources in California.

The State's Economic Health and the Utilities

Though only one of many factors contributing to the state's economic and fis cal position, the electric infrastructure retains its vital role. For many industrial, commercial, and agricultural consumers, electric bills can represent a significant portion of the expense of doing business. For residential consumers, electric bills may comprise a considerable portion

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164 Various news accounts put the deficit for the 1992-1993 fiscal year at $9-10 billion.

165 Council on California Competitiveness, California's Jobs and Future, April 23, 1992., Chapter 1.

166 Considerable evidence of this is found in California Energy Demand; 1991-2011, Volume X II: Long Term Economic Projections, California Energy Commission, February 1992.

167 Various economists cited in recent news reports believe that while the national economy may begin to pick up, California's economy will get worse before it gets better. Most recently the business forecasting project at the UCLA management school expressed this view. San Francisco Examiner, December 15, 1992, p. A1.

of the family budget, and bill increases can cut deeply into disposable income. As such, the price of electricity can place constraints on the state's economy.

An electricity infrastructure providing low-cost, high quality electric service will take on increased importance in the future. With the weakening, or disappearance, of regional and international trade and financial barriers, competitive pressures have increased dramatically. As these barriers continue to fall, competitive pressures, and the pressure to provide low-cost, high quality electric services, will mount. The importance of maintaining an efficient electric infrastructure for California will increase as those pressures heighten.

What the Utility is Likely to Face

Accompanying predictions of a sluggish economy are forecasts of stable inflation and interest rates, natural gas prices, and electricity prices.

Near term forecasts see the continuation of the relatively low, stable inflation and interest rates of the 1980s and early 1990s. Projections place the increase in the Consumer Price Index in the range of three to five percent for the next three years.[168]

Analysts expect natural gas prices to rise moderately throughout the 1990s. For example, the CEC predicts a price of \$2.10 per cubic foot in 1992, rising to \$8.76 per cubic foot by 2011.[169] This is due in part to this Commission's ongoing efforts to foster greater competition in the supply and transportation markets serving California. The construction of

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168 PG&E, "Pre-Election Economic Outlook 1992", P.8.

169 Prices are at the California border and are in nominal dollars, from 1992 Electricity Report, Appendix A, "Electricity Systems Planning Assumptions Report," Volume III. P. AIII-194. The \$8.76 is equal to \$4.15 in constant 1992 dollars assuming a 4% annual inflation rate.

additional interstate pipelines into the state should further fuel competition within these markets and help sustain low prices.

Geopolitical events such as those which led to the 1990 Gulf War illustrate the difficulty of predicting future oil prices. But, while fossil-fired generating capacity remains in the state's infrastructure, the state's IOUs currently rely on oil for only negligible amounts of their generation, significantly mitigating price risk resulting from future oil supply disruptions.[170] That risk will diminish further as the state's utilities--increasingly sensitive to risks associated with air quality regulations and fluctuating fuel prices--continue the shift to natural gas-fired resources.[171] Finally, the past decade has seen the weakening of the link between oil and natural gas prices, as natural gas prices no longer follow swings in oil prices, further reducing the threat of price volatility in natural gas markets.

The Future Leaves the Utility's Financial Prospects Uncertain

Though most analysts expect favorable inflation and interest rates, and stable fuel prices to continue through the near term, the financial position of the state's investor-owned electric utilities remains nonetheless uncertain. This uncertainty arises from risks common to a majority of the nation's utilities, and comes despite the fact that California's IOUs are among the healthiest in the industry.[172]

Favorable Economic Trends Mean Lower Utility Returns

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170 See Chapter V.

171 This increasing reliance on natural gas is largely attributable to environmental concerns, due to the pollution effects of burning oil and the desire to have the state's IOUs less dependent on fuel oil, most of which the U.S. imports.

172 See Chapter V for a description of some of the key financials of California's IOUs.

Improved economic and financial conditions translate to lower risk for the utility and generally prompt regulators to lower the utility's authorized returns on equity and rate base commensurately. As early as February of this year, analysts predicted national rates to drop from an average of 12.45% to approximately 11.75% in 1993.[173] They based their predictions on the regulatory community's response to rapidly falling interest rates during 1986.

In November of 1992, this Commission lowered PG&E's, Edison's and SDG&E's return on equity for 1993 from 12.65 percent to 11.90, 11.80, and 11.85 percent, respectively, though each remains above the 11.75 percent average rate predicted.[174] Thus, the Commission secured for utility consumers the benefits of lower utility financing costs brought about by falling interest and inflation rates.[175]

Threats to Utility Market Share

Perhaps the biggest financial threat facing the state's IOUs stems from lagging sales and the loss of existing and future market share. Sales growth, particularly growth linked to the high-volume industrial and commercial sectors, has declined.[176] And while some portion of this decrease is explained by the cyclic character of the economy, the rate-cost gap, technological improvements, and increased reliance on competition within the industry are

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173 Fitch Insights, "Electrics Adjust to Lower Rates"; February 3, 1992; p. 9.

174 Decision 92-11-047.

175 Ratings agencies responded to the Commission's actions by lowering Edison's rating on preferred equities from A+ to A-.

176 Conversation with Barbara Barkovich, regulatory representative of California Large Electric Consumers Association. See also Fitch Insights, "Electrics Inch Ahead," March 2, 1992, p. 10.

also likely contributors, and may accelerate the decline in sales in coming years. These trends will put a growing portion of the utility's industrial and commercial share of the market at risk as customers continue to look beyond the utility for less expensive forms of electric service.[177]

Utility Rates and Existing Market Share

Though considerable differences of opinion continue in the debate over the future level of utility rates, at least one source predicts that when adjusted for inflation, rates are likely to decline, or rise only slightly, over the next 20 years.[178] These predictions anticipate that PG&E's rates will rise from the 1989 level of 8.9 cents per kWh to 9.30 cents per kWh in 1996; by 2003, rates are expected to drop to 8.80 cents per kWh.[179] In Edison's Planning Area rates are expected to decline from a high of 9.52 cents per kWh in 1989 to 7.90 cents per kWh in 2003, rising slightly to 8.33 cents per kWh by 2011. San Diego Gas and Electric's rates are predicted to rise moderately from 8.58 cents per kWh in 1989 to 8.97 cents per kWh in 1996, declining to 8.46 cents per kWh in 2003 and 7.81 cents per kWh in 2011.

Yet despite forecasts projecting stable electricity prices, average rates for California's IOUs ranged from approximately 9 to 10.5 cents per kWh in 1991, thirty to fifty percent *above* the national average.[180] And with the competitive cost of supply-side services

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177 See Chapter VI for a detailed discussion of possible reasons for the gap and its implications.

178 All figures cited here are system average electricity rates in 1989 dollars. Figures taken from the CEC's Draft Final Electricity Report, November, 1992, page 2-13. All rates are adjusted for inflation.

179 Each of the rates listed are in constant, 1989 dollars.

180 Information provided by the Division of Ratepayer Advocates from FERC Form 1.

currently ranging from 6 to 8 cents per kWh,[181] technological advances will likely sustain the rate-cost gap in the future, despite any real decreases in utility rates.[182] Persistence of the gap means continuing threats to existing utility market share.

The Competition for Future Market Share

Apart from the risk of losing existing market share, the utility faces further uncertainty in the market for incremental electric service. Between 1978 and 1990, twenty percent of all new generating capacity in the U.S.--more than 40,000 megawatts--has been constructed by nonutility providers. In 1990, non utility providers made up approximately 6% of total generation in the United States. The same nonutility providers brought 6,356 megawatts on line in 1990--about half of the U.S. total--representing an investment of approximately eight and one-half billion dollars. What is more, some experts expect the nonutility sector's total share of U.S. generation to climb to fifteen percent by 2005. And recent Department of Energy estimates place forty percent of new generation with nonutilities; some estimates go as high as fifty percent, with total investment ranging from fifty to seventy billion dollars.[183]

California has experienced some of the most notable growth in the independent power

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[181] Information supplied by PG&E in response to an informal data request, December 1992.

[182] The South Coast Air Quality Management District has already installed a state-of-the-art fuel cell. Further advances in the technology may put additional Edison sales at risk of future bypass. Moreover, Section 1212 of the Energy Policy Act of 1992 authorizes incentive payments for a period of ten years to the owners or operators of qualified renewable electric energy generation facilities. The incentives amounts to 1.5 cents per kilowatt hour generated and could further advance the potential technological improvements and for bypass. For examples of the current state of the bypass threat see "Businessmen Finding Cheaper Electricity," Albuquerque Journal, August 14, 1992, and "Utility Deregulation Sparks Competition, Jolting Electric Firms" Wall Street Journal, June 6, 1992, p. A5.

[183] Fitch Investor Services, Fitch Insights, June 8, 1992.

industry. QF power currently accounts for nearly 20 percent of IOU generation in the state.[184] QF providers supplied approximately 56 percent of all new generation brought on line in California since 1982. That share is expected to grow as the state's IOUs prepare to undertake California's first competitive bid; it may increase if the useful lives of utility resources are shorter than expected.

In addition, California has historically enjoyed abundant, relatively low-cost power from hydroelectric sources in the Pacific Northwest. But competing demands for water--particularly in light of the growing number of endangered salmon species and a prolonged drought--and the shutdown of the Trojan nuclear plant has made Bonneville Power Administration (BPA) a net *purchaser* of power. That trend is expected to continue.[185] If so, the state could face substantial reductions in the supply of power, which would force utilities to seek alternatives, potentially increasing nonutility market share.

Additional challenges facing California's IOUs could further erode the utilities' resource base--and its market share. Burdened with relatively high-cost nuclear generating capacity, SCE and SDG&E requested, and the Commission approved, the early retirement of one of the San Onofre Nuclear Generating Station units.[186] Early retirement of nuclear facilities is not limited to California.[187] If these retirements continue--as some believe they will--the need to

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184 This figure includes the investor-owned utility plants placed on standby reserve. Source: ER92 Appendix B, Resource Accounting Tables.

185 John E. Bryson in a speech before financial community projected a need for 3600 MW of additional capacity in the Pacific Northwest over the next decade. .

186 D.92-08-036.

187 In mid-1992, owners of the Trojan nuclear power plant decided to retire the plant rather than invest in costly upgrades. Northeast Utilities, New England Electric, and Boston Edison are fighting FERC for the right to retire their Yankee Atomic Generating Station rather than invest in a costly life extension plan. El Paso Electric is trying to relinquish its 7 percent share of the Palo Verde Units.

procure additional resources could surpass current estimates and the utility could see its market share dwindle further in competition with independent generators.

Environmental pressures could further place utility market share at risk. The South Coast Air Quality Management District, confronting some of the worst air quality problems in the nation, has taken bold steps to reduce harmful pollutants. However, despite the District's innovative efforts to reduce the cost of compliance by establishing an emissions trading program, Edison may nonetheless find it cost-effective to retire aging, inefficient plants, rather than invest in expensive control equipment, or emission permits.[188]

In short, California's IOUs, and the electric industry generally, are poised to embark on the first significant construction cycle in more than two decades. Depending on the future performance of the nuclear facilities and the effect of more stringent environmental safeguards the amount of new construction could increase. Faced with a highly competitive, and highly efficient nonutility sector, neither the utility's market share nor its financial standing are secure; this despite interest and inflation rates not seen since the industry's "glory days" following World War II. The threat to the utility of diminishing sales places greater emphasis on the Commission's resource procurement proceedings, where regulatory advantage is sought in the competition for market share.

As troubling as these threats may be, the stakes increase substantially as customers begin to look beyond *technological* alternatives and seek *direct access* to alternative service providers through retail wheeling, thus placing an even greater portion of the utilities' sales (and revenues) at risk. The indicators suggest that regulators and/or legislators are likely to

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188 To the extent the State, in partnership with California's business community, pursues an environmental strategy focused on electrification, the demand for electricity could markedly increase. Any such increase does not ensure market share for the utility, however, since under current regulation the majority of incremental demand will likely be met through competitive auction.

respond to calls for customer choice.

Electric Transmission: Customer Choice Requires Access

As a result of PURPA and state and federal policies governing independent power, many view the generation portion of the electric services industry as competitive. Utilities in California--and throughout the country--retain monopoly control over electric transmission and distribution systems, however. This control can significantly affect the degree of competition by limiting access to markets. Consequently, many, including this Commission, view transmission access as the principal barrier to the development of a workably competitive electric services market. Indeed, the issue of nondiscriminatory transmission access--and the IOUs' alleged reluctance to provide it--has been the subject of considerable controversy both in California and throughout the country.[189]

Those traditionally opposed to open transmission access fear that the policy will compromise system reliability; force the utility's native load customers to subsidize the costs of providing transmission service for independent generators and other utilities; threaten the utility's share of existing and incremental electricity sales; and, saddle the utility and its customers with the unamortized portion of capital investments for which prior regulatory approval was sought and gained--so-called "stranded investment."

But the transmission provisions of the Energy Policy Act, policy direction at the state and federal level, and transmission programs underway in the U.S. and abroad suggest that while these issues merit serious scrutiny, they are nonetheless manageable. Moreover, FERC's new authority under the Energy Policy Act to mandate transmission service under certain conditions confirms that the debate over whether electric utility systems are simply too technically complex--and the stakes too high--to accommodate wholesale wheeling is over.

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189 See Chapter V.

And though FERC's authority to mandate wholesale wheeling constitutes a sea change in U.S. energy policy, growing pressure to allow retail wheeling is equally if not more significant. In a letter to Chairmen Dingell of the Energy and Commerce Committee, approximately one hundred of the country's largest industrial consumer groups urged Congress to allow retail wheeling as part of the Energy Policy Act.[190] Supporters assert that retail wheeling is technically feasible and beneficial to consumers, since it offers enhanced ability to manage energy costs by choosing among competing service providers.[191]

To support the argument that no technical impediments exist to retail wheeling as a policy option, proponents cite the success of retail wheeling underway in the United Kingdom; the Michigan Public Service Commission's experiment with retail wheeling in the Detroit Edison and Consumers Power service areas; retail wheeling services PG&E currently provides the City of San Francisco; and the Texas Public Utilities Commission recently issued rule proposing retail wheeling as a demand-side management tool.[192]

The Western Systems Coordinating Council's Western System Power Pool provides further evidence that dispatchers can successfully schedule extremely complicated power transactions over a complex transmission network, linking numerous utility systems in states west of the Rockies.[193] Under the WSCC, guidelines once designed to balance low-cost operation and reliable service within utility-specific systems have expanded to apply on a much a larger scale, effectively integrating the electric infrastructure in the West. Customers

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190 Letter from "A Coalition of Industrial Electricity Users" to The Honorable John D. Dingell, June 16, 1992.

191 Retail wheeling provides customers with direct access to electricity providers, while a policy limited to wholesale wheeling excludes access to end users.

192 See The Electricity Journal, "Retail Wheeling: Get Ready," November 1992, pp 4-5.

193 Regional councils similar to the WSCC exist throughout the U.S.

in Arizona receive power from the Pacific Northwest; SDG&E supplies power purchased from Wyoming and Montana to its customers in Southern California. Recently crafted "environmental" power exchanges between BPA and California utilities provide economic benefits by helping to restore salmon populations in the Pacific Northwest and improving air quality in the Los Angeles Basin.[194]

Many believe emerging regional power exchange markets, like the one managed by the Western System's Power Pool, will propel this "new regionalism" within the electric industry, prompting electric consumers to increase demands and providers for the kind of market access choice retail wheeling offers. Though considerable debate continues over FERC requirements governing the Pool's membership and pricing policies, the WSPP's success illustrates the technical feasibility of developing a voluntary spot market for electricity.[195] So successful in fact, that the New York Mercantile Exchange views WSPP as a promising foundation on which to begin developing an electricity futures contract.[196]

194 Still other events suggest that something akin to a centrally dispatched "Western Utility System," stretching from Canada to Mexico, and from California to the Rockies, may emerge in the future. First, the North American Free Trade Agreement significantly lowers trade barriers in North America--barriers which currently constrain power exchanges among Canada, Mexico and the U.S. Second, confirming the increasing irrelevance of state and national borders in the electric services market, the Western Systems Coordinating Council Executive Committee adopted a resolution in 1990 calling on the WSCC to "undertake the responsibility for identifying opportunities to enhance coordinated regional planning and operation." In November of 1991, the Committee on Regional Electric Power Cooperation proposed a draft resolution supporting a role for the WSCC in regional planning. (The Committee is a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners and includes the regulatory and energy planning and siting agencies in the WSCC region and the Provinces of British Columbia and Alberta.)

195 While most agree on the technical feasibility of an electric spot market, legal and contractual hurdles constrain the market.

196 Conversation with Robert A. Levin, Vice President of Research, New York Mercantile Exchange.

CHAPTER VII

Proponents of policies that would allow customers greater choice among service providers turn to these technical accomplishments and the benefits that accompany them to support the desirability of retail wheeling. They assert, as did the signatories to the letter to Chairman Dingell, that "...open access to energy--with appropriate regulatory safeguards--protects all consumers by forcing inefficient utilities to provide better service and rates."[197]

Still other events could increase the pressure for retail wheeling.

Once such event is the completion of the California-Oregon Transmission (COT) project, a municipally-sponsored transmission line stretching from the Pacific Northwest to Southern California. The COT project will increase transmission capability by 9,400 MWs. Some observers conclude that the municipal owners of the line have need for approximately one-half of project's total capacity, leaving a substantial amount available for purchase. With utility prices currently well above the "market" price of electricity, many large consumers may urge decisionmakers to allow them to purchase power over COT, and have the utility transmit the power over their system.

Sections of this paper suggest that aging nuclear plants and stricter environmental regulation could push the state's resource requirements above current projections. If this occurs, pressure to allow customers direct access to, and thus greater choice among, service providers could increase significantly. To the extent early retirement leads to a growing amount of capacity procured through a competitive auction, large consumers and nonutility service providers will press for the opportunity to choose among the new crop of low cost providers to avoid paying utility rates which are likely to exceed market rates.

The Energy Policy Act's reform of the Public Utilities Holding Company Act (PUHCA) will add to this pressure. The Act's exemption from PUHCA of a new class of independent wholesale providers lowers barriers to entry and promotes competition in the electric services

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197 Letter to Chairman Dingell, op. cit.

market.[198] The entrance of additional low-cost providers into the market, and mounting evidence that retail wheeling is technically feasible, will prompt businesses facing competitive pressures to demand the opportunity to sidestep high-priced utility services and seek out the benefits that accompany enhanced competition and increased choice.

Signs of Mounting Pressure to Allow Choice in California

In California, the Commission is already feeling the pressure to allow retail wheeling in its investigation to develop a policy on nondiscriminatory electric transmission access for nonutility providers.

Noting that "California's large industrial customers face electric rates in neighboring states that are roughly half the level of those in California," the California Large Energy Consumers Association (CLECA) recently called on the Commission to expand its investigation to include retail wheeling.[199] In support of its request, CLECA points to the fact that while the Energy Policy Act of 1992 precludes FERC from ordering retail wheeling, it leaves intact the jurisdiction enjoyed by state commissions, including authority over retail electric service.

In addition to CLECA's request, the State's Department of General Services has asked the Commission to include "self-service" retail wheeling as an issue in the upcoming phase of the same transmission investigation.[200] Both requests were denied.[201]

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198 The Act refers to this new class of providers as "exempt wholesale generators," or EWGs.

199 CLECA, Prehearing Conference Statement in OII 90-09-050, p. 2.

200 The Department of General Services, Prehearing Conference Statement in OII 90-09-050.

201 Reporter's Transcript of Prehearing Conference in I89-07--4 and I.90-09-050, p. 359.

And pressure is also mounting in the Legislature. CLECA recently requested that the Senate introduce legislation directed at reforming various aspects of the regulatory process for electric energy rates. Under CLECA's proposal, that reform would include retail wheeling.[202]

Finally, there remains an additional, more subtle, indication that increased choice is likely to occupy a prominent place on the future agenda of the electric industry. It is currently tied, but not necessarily limited, to growing concerns over the balance between economic growth and environmental quality.[203]

Southern California Edison, in cooperation with the Regulatory Assistance Project of Maine, has proposed an innovative new approach to investment in environmentally sensitive utility resources. The goal of the program, called Green Pricing, is described by Edison as the "acceleration of renewable resource development through *customer choice*." Green pricing would allow customers to voluntarily pay a surcharge on rates that Edison would then devote to the development of renewable resources.

In the same way large industrial customers are calling for choice as a means to enhance competition and better manage energy costs, customers valuing service provided by environmentally sensitive technologies could add to those calls and increase the pressure,

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[202] Letter from the Honorable Robert Presley to Commission President Daniel Wm. Fessler, December 22, 1992.

[203] A July 1992 poll by the Wirthlin Group indicates that 80% of Americans believe that environmental standards "...cannot be too high and continuing environmental improvements must be made regardless of cost." The same survey found that 77% of the American public believes that it is possible to balance economic growth and environmental quality. Only 4% would sacrifice environmental quality for economic growth.

In a similar poll conducted by the Roper Organization, the Times Mirror Magazines found that a majority of Americans are "...optimistic that environmental quality and economic development 'can go hand in hand'."

demanding direct access to "green" service providers.

Although its proponents failed in 1992 to secure retail wheeling in the Energy Policy Act, efforts to secure it at the state level are likely to mount rather than wane. One indication is the increasing number of industry experts who believe that some role for retail wheeling is inevitable in the electricity industry's future. As one participant concluded at a gathering of investor-owned utilities as part of the Edison Electric Institute's annual financial conference: "Our preferences, pro or con, are immaterial. Retail wheeling is probably inevitable..."[204]

For many, increased customer choice is upon us, with the only remaining question: When, and in what form, will the change take place?

[204] Comments of John Hayes, chairman, president, and chief executive officer of Western Resources. The Electricity Journal, op. cit., pp 4-5.

CHAPTER VII

Some Lessons from the Past and Prospects for Change

Those who predicted the coming of wholesale wheeling over the past decade did so against an impressive majority who viewed the possibility as highly unlikely, at best. In the 1970's and 1980's there was similar resistance to change in the natural gas and telecommunications industries. Yet today competition and customer choice are well advanced in those industries in part due to state and federal policies designed to increase direct access to alternative providers.

Though considerable differences exist between the natural gas and electric industries, the wheeling provisions under the Energy Policy Act, and recent court and FERC decisions, provide additional evidence to suggest that more choice, not less, is on the horizon.[205] For example, recent FERC decisions granting utility mergers linked approval to transmission access.[206] But the decision to exclude qualifying facilities and end-users from the merger's transmission provisions was appealed to the D.C. Circuit. Citing what it viewed as an inconsistency "with the position [FERC] has taken under the Natural Gas Act in the comparable situation involving end users by-passing a local distribution company," the court remanded the decision to FERC for further consideration.[207] FERC later upheld its decision

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205 For an excellent analysis of the similarities between FERC's actions in the natural gas and electric industries, see Bobbish, Donna J., "Deja Vu at FERC: What Path for Electric Restructuring," Electricity Journal, June 1992. As early as 1986, Phillip O'Conner urged the industry to observe and understand the lessons of competition from a variety of industries--including the natural gas and telecommunications industries--and warned the electric industry to brace itself for retail wheeling. Paul Joskow has also written on the subject (see "Conflicting Public Policy Goals, Changing Economic Constraints and the Future of the Regulatory Compact," prepared for a seminar on the regulatory compact sponsored by the California Foundation on the Environment and the Economy, July 16-17, 1992).

206 See for example, Utah Power & Light Co., Opinion No. 318, 45 FERC (1988); Northeast Utilities Service Company, Opinion No. 364, 56 FERC (1991); and Entergy Services, Inc., 58 FERC (1992).

207 Environmental Action V. FERC, 939 F.2d at 1063, in Bobbish, Donna J., op. cit. p. 62.

to exclude QFs from the merger's transmission conditions.

Despite FERC's inability to order retail wheeling, its authority over wholesale wheeling is nonetheless substantial. Couple this with the fact that FERC has already shown considerable interest in enhancing access when it could (i.e., in merger decisions), and the D.C. Circuit's nod toward increased choice in the Utah Power & Light case, and the momentum for direct access seems to be growing.

Increased access in both the natural gas and telecommunications industries did not emerge without opposition.[208] Some of that opposition came from state commissions, yet dramatic restructuring occurred nonetheless. Given the pressures described above, state commissions (and others) may experience similar difficulty opposing the call for greater choice within the electric industry.

Forces which May Decrease the Pressure for Greater Choice

Despite trends favoring the development of direct access in the electric industry, there remain others which might lessen the push. The Energy Policy Act's ban on FERC-mandated retail wheeling may reduce the likelihood that retail wheeling will materialize quickly. If the state Legislature seeks to prevent this Commission from ordering retail wheeling, speculation would quickly end in California.

A robust economy could further reduce the pressure for increased access to electric service providers. The simultaneous occurrence of a global recession and the state's economic restructuring has sharpened the focus on energy-related business expenses and the rate-cost gap. If the pace of economic growth in the state quickens, that focus may shift, though rapidly increasing global competition is likely to offset the effect of an improved

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208 In the phone industry, access and choice arose largely from the break-up of AT&T by the courts, not from an explicit regulatory policy. See for example Coll, Steve, The Deal of the Century: The Breakup of AT&T, New York: Simon and Schuster, 1986.

economy.

In addition, regulatory and/or legislative initiatives could reduce the gap between utility rates and costs and thus ease the pressure for increased customer choice. For example, the Commission could allow the utility to accelerate the recovery of large portions of the revenue requirement tied to the nuclear facilities. This would raise customers rates in the near term, but would make the utility more able to compete in the long run. Alternatively, the utility could write down some portion of this revenue requirement, asking shareholders to participate in the restructuring necessary to enhance the utility's competitiveness. In addition, the Legislature could decide to fund certain utility programs through the general fund rather than through utility rates. These might include programs related to low-emission (natural gas and electric) vehicles; economic development; low-income assistance; and other services the utility's competitors are not required, or choose not, to provide.

Environmental policy could also close the rate-cost gap. For example, a state- or federally-imposed tax on carbon emissions designed to cover all pollution sources--including utility customers looking to self generation or cogeneration opportunities--may bring the cost of competing alternatives and utility service closer together. Finally, an end to the state's lingering drought would allow the utility to make greater use of its cheap hydraulic resources, further curbing operating costs. Heightened demands calling on the state to redistribute the state's water resources toward restoration of the state's fish and wildlife habitat could offset the effects of increased rainfall, however.

While each of these events may somewhat mute calls for increased customer choice, the extent to which they outweigh trends prompting those calls is uncertain.

Promising Signs for the Utility Remain

Amidst the financial risks the state's utilities are likely to face in the future, restructuring within the U.S. electric industry and emerging markets abroad offer considerable opportunities. First, despite the state's severe economic recession and the challenges facing utilities, this Commission, and commissions across the country, have succeeded in providing an environment which fosters financial strength.[209]

Second, in an attempt to provide the utility with the means to manage changes underway in the electric services market, Commission policy currently allows the utility some flexibility in its resource procurement decisions. For example, beyond the competitive solicitations slated for 1993, sufficient capacity requirements will remain on (at least) SDG&E's and Edison's systems to allow substantial capital investment by both companies in the repowering of existing facilities. The companies are not required in every case to subject those projects to competition, effectively assuring near-term utility investment and revenue opportunities.

Third, California's utilities continue to enjoy considerable success in utility-related markets outside the IOUs' service territory. For example, PG&E's subsidiary, U.S. Generating Co., and SCE Corp's Mission Energy compete successfully for independent power contracts in the U.S. and abroad.[210] So successful are they that together with Virginia Power Co., PG&E and Edison affiliates account for more than *one-half* of the approximately 2,800 megawatts of utility-affiliated generating capacity in the U.S..[211] Utility affiliates are

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[209] Citing the fact that dividends for Standard & Poor's 40 Utilities have increased every year since 1952, and doubled between 1977 and 1991, one utility investment analyst recently advised, "Utility stocks should be a part of every investor's portfolio." The same analyst suggests that signs of an improving economy make investments in utilities still more attractive. Topping his list of utilities expected "to rack up" returns of nine to ten percent over the next several years is SCECorp. (Statesman Journal, Commentary of Dan Dorfman, October 26, 1992. The analyst cited is Mr. John Lennon of Colonial Utilities Fund.)

[210] Mission Energy currently provides a considerable amount of power to Edison. However, a settlement pending before the Commission between the Division of Ratepayer Advocates and Edison would prevent future Mission plants from selling power to Edison.

[211] Mission Energy is the largest independent power producer in the U.S. and one of the

also very active overseas, where market opportunities are on the rise based on expectations of rapid demand growth.[212] Affiliate participation in markets may mitigate the financial risks that utility holding companies face due to increased competition for market share within the utility's own service area.[213]

Recognizing the economic and environmental value of employing demand-side management techniques to meet energy requirements, PG&E has further expanded to form an energy services company affiliate, Sycom.[214] Building on the company's success in capturing energy savings for its customers--delaying both the need for and the cost of

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largest in the world. (Comments of John E. Bryson, Chairman and CEO of SCECorp, to financial analysts, November 3-4, 1992.) Utility affiliates currently account for about 14% of nonutility capacity in the U.S. This success is attributed in part to the nature of *nonutility* project financing, which "provides a strong incentive to perform." (Fitch Insights, June 8, 1992, p.9.)

212 For example, in addition to Mission's ownership interest in over 1,300 MWs of projects located within the U.S., projects awaiting permit or under construction both at home and abroad are expected to double that amount by 1995. Mission's overseas locations range from England to Indonesia, and Australia to Mexico (Bryson, op. cit.). As of January, 1990, U.S. Generating Co. (formerly PG&E-Bechtel Generating Company) had ownership interest in 1,700 MWs of projects.)

213 Edison CEO John Bryson has noted the "increasingly important role" nonutility subsidiaries will play in order to "to broaden [SCECorp] earnings." (Public Utilities Fortnightly, September 1, 1991, p. 12.) In 1991, subsidiaries accounted for over sixteen percent of SCE Corp's earnings per share, up from approximately twelve percent in 1990. (SCECorp 1991 Annual Report to shareholders.)

214 In 1990, the Commission approved a proposal to provide utilities with the incentive to pursue energy savings (and revenues) in the electric services market--a niche historically rendered less attractive under traditional cost-of-service ratemaking practices. Between 1990 and 1992, PG&E earned $113 million in incentives on energy savings achieved from $340.5 million dollars of investment in DSM programs. SDG&E earned $27 million on an investment of $98 million, and Edison earned $21.1 million from $358 million dollars of investment in DSM. "A Review and Analysis of Electric Utility Conservation Initiatives," November 1992, Gilbert, R., and Stoft, S.

constructing additional generating capacity--similar success by Sycom will help further reduce PG&E's financial exposure from increased competition in the generation market within its service area.[215]

SDG&E has also formed unregulated subsidiaries. For example, Wahlco Environmental has experienced considerable growth marketing environmental products and services in the U.S. and around the world. Wahlco increased its holdings in 1991, purchasing three European companies that market products used in utility power plants and industrial facilities.[216]

Ironically, the success of utility affiliates contributes to the growing interest in competition as a least-cost acquisition strategy. It also contributes to the mounting demands made on regulators to allow customers to choose among electric services providers, and consequently, to the increasing competition and financial risks the utility currently faces.

Some Risks from Utility Diversification

Diversification by the utility industry grew rapidly during the 1980s. That growth is expected to continue.[217] And though successful in some areas, experience has shown that

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[215] Each of the IOUs have numerous subsidiaries and affiliates engaged in a variety of utility-related and non utility-related activities. For example, PG&E has affiliates in businesses ranging from the production and marketing of "fine chemicals" (ANGUS Fine Chemicals Ltd.), to financial services (Pacific Conservation Services Company), to insurance services (Mission Trail Insurance (Cayman) Ltd.), to gas pipeline transmission services (Foothills Pipe Lines (South B.C.) Ltd.), to magnesite ore processing (Magnesium Company of Canada Ltd.), to oil and natural gas exploration (PG&E Resources Company), to real estate (PG&E Properties, Inc.) (PG&E 1989 Financial Report to Shareholders, pp. 26-27). Only a few are discussed here for illustrative purposes.

[216] SDG&E 1991 Annual Report to shareholders, p. 18.

[217] See for example, Wall Street Journal, "Entergy Pursues Tricky Path of Utility Diversification," November 1, 1992, and "SEC, in Landmark ruling, Finds PUHCA Does Not Impede Foreign Investments," Electric Utility Week, pp 1, 14-15. On June 29, the Securities

some types of diversification are more secure than others. For example, while SDG&E's Wahlco affiliate recorded impressive earnings in 1991, those gains were "offset by losses suffered in [its] real estate business..."[218] And in 1992, Moody's Investor Services saw fit to downgrade approximately $1.5 billion of Southern California Gas Co. debt due to the Company's "substantial capital expenditure program" and a "string of large writedowns related to [Pacific Enterprises'] decision to sell most of its money-losing nonutility business."[219] Such downgradings resulting from less-than-expected performance by subsidiaries and affiliates can impose additional costs on consumers served by the regulated utility and weaken the utility's financial position. This risk seems greatest when diversification extends beyond utility-related business.[220]

Tied to concerns over financial risk and adequate consumer protection is the question of whether regulators have the reserves required to adequately oversee the activities of utility subsidiaries and affiliates. The threat of cross-subsidization poses particular concern. Some worry that diversification creates an incentive for the utility to have consumers fund the development of assets and personnel through its regulated utility, and later transfer the most highly-valued among them to the unregulated side of the company. Overseeing this sort of activity can be particularly difficult and administratively costly as the number and location of subsidiaries increase.

Others, including the Securities and Exchange Commission (SEC) in its decision

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Exchange Commission granted SCECorp (and Mission Energy) "an unqualified exemption" from PUCHA.

218 SDG&E 1991 Annual Report to shareholders, p.18.

219 SoCal Gas strongly opposed the downgrade, asserting the company has "worked very hard over the decades to ensure that the gas company maintains it financial independence."

220 Wall Street Journal, "Entergy Pursues Tricky Path," op. cit.

granting SCECorp (and Mission Energy) an exemption from PUHCA, believe that existing Commission authority is adequate and the necessary safeguards are available to prevent cross-subsidization.[221]

These observations aside, the utility is likely to respond to the threat of shrinking market share in its service area, and the opportunities offered by growing markets at home and abroad, by increasingly emphasizing a diversification strategy. Utility implementation of that strategy signals a marked change in the structure of the electric utility industry, both in California and around the country. Recent reform of the nation's electric transmission policy and PUHCA will hasten that change, further prompting the need to reexamine the Commission's regulatory programs. To help foster discussion about how the Commission's regulatory programs might evolve, the following chapter offers a range of strategies for consideration

221 See SCE Corp. and Mission Energy application for 40% equity stake in Loy Yang B, granted by the SEC in an order dated June 29, 1992. Release No. 35-25564; International Series Release No. 405.

CHAPTER VIII

THE NEED FOR REGULATORY REFORM

This study's principal conclusion is that the Commission should reform the state's regulatory program governing California's electric industry. Contemporary cost-of-service regulation, as currently practiced in California, is ill suited to govern today's electric industry. It is less well suited to govern the industry that is likely to emerge in the coming years. The problems are rooted in the incentives inherent in current regulation and in the multiplicity and complexity of the proceedings that have evolved over the past two decades.

Accordingly, this study offers alternative regulatory approaches. This chapter offers four potential strategies for consideration by the Commission and interested parties. The chapter includes a description of the principles developed and used to guide strategy formulation. The chapter also defines criteria against which each reform strategy is measured. Finally, the chapter includes an assessment of the strengths and weaknesses of each strategy.

Why Reform is Necessary

For two principal reasons, this study concludes that the state should reform its regulatory program governing the electric industry.

o **California's current regulatory framework, significant portions of which were developed under circumstances which no longer persist, is ill suited to govern today's electric industry.**

The fundamental tenets of California's contemporary regulatory compact emerged when the monopoly character of the electric utility industry was strong and secure. Today, competitive pressures and emerging market forces exert increasing influence over the structure of the industry, and the utility's monopoly position is less intact. Consequently, the Commission should make appropriate reforms in order to establish greater compatibility between regulation and the industry that regulation guides.

o **The state's current regulatory approach is incompatible with the industry structure likely to emerge in the ensuing decades.**

Mounting competition among energy service providers and increased pressure to allow consumers to benefit from competition through greater choice will shape the future structure of the industry. As such, reform is required in order to ensure that California is well positioned to benefit from a competitive future.

CHAPTER VIII

Key Problems Prompting Reform

This study's call for regulatory reform is rooted in the conclusion that contemporary cost-of-service regulation and utility resource procurement in California pose several problems for the Commission, the industry, and the state's consumers of electric services. Specifically the current regulatory program:

1) **Blunts incentives for efficient utility operations;**

2) **Increases the potential for inefficient investment due to unbalanced incentives governing utility investment decisions;**

3) **Requires a multiplicity of complex proceedings, which increase costs and threaten the quality of public participation and Commission decision making;**

4) **Offers utility management limited incentives and flexibility to respond to competitive pressures; and,**

5) **Impedes the Commission's ongoing effort to enhance competition in the development and delivery of electric services.**

Each of these problems is discussed briefly below.

The current regulatory program blunts incentives for efficient utility operations.

The Commission and industry observers have for some time recognized that contemporary cost-of-service regulation leaves the utility with weak incentives to operate efficiently. First, traditional cost-of-service ratemaking offers the utility a dominant incentive to overestimate its operating costs and underestimate its sales. If this behavior goes undetected by the Commission, the utility benefits through increased profits. It retains those profits until the Commission has the opportunity to correct the estimates in subsequent general rate cases. To the extent the utility engages in this sort of manipulation, consumers may pay excessive rates for services rendered.

Second, though the recent addition of balancing accounts and rate adjustment mechanisms mitigate somewhat the incentive to manipulate cost-of-service regulation, these accounts and mechanisms may dampen incentives for the utility to operate efficiently. For example, absent demonstrably imprudent management, balancing accounts significantly reduce the financial risks of unforeseen events which can affect both utility expenses and revenues.[222] As a result, the utility faces weak financial incentives to perform efficiently since these regulatory mechanisms automatically adjust rates to capture fluctuations in the specific components covered by the mechanism.[223]

Balancing accounts and rate adjustment mechanisms were principally created in response to the volatile conditions of the 1970s and 1980s (see Chapters IV and V). At that time, the Commission determined it was both appropriate and necessary to encourage efficient operations by replacing the *financial* incentives embodied in traditional cost-of-service ratemaking with interventionist *regulatory* procedures.[224] Over time, the volatility

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[222] Fuel costs and electric sales are two examples of areas in which the utility would face greater financial risk absent balancing accounts and rate adjustment mechanisms. It should be noted, however, that many utilities attach considerable financial risk to the *ex post* reasonableness, or prudence, reviews that accompany these accounts, irrespective of any reduction in risk they otherwise offer.

[223] These examples are offered keeping in mind that Commission oversight of utility expenses in the general rate case, and the threat of *ex post* review of fuel and power purchases may reduce the incentive to manipulate the process. However, this effect is generally assumed to be weak since in most cases the utility possesses better information than the Commission. In addition, the threat of customer bypass and the possibility that the future may bring increased competition at the retail level may also reduce the incentive to "pad" operating costs. But the extent of the reduction remains unclear.

[224] The financial incentive noted here is discussed in greater detail in Chapter VI. Briefly, the incentive is linked to estimates of the utility's operating expenses made in the general rate case. To the extent the utility provides service "more efficiently" (i.e., at a lower cost) than the rate case estimates, the utility retains the profits until the next general rate case. Thus absent any manipulation of the sort mentioned above, and provided the process accurately estimates utility costs, the profit motive offered by a cost-of-service ratemaking framework

prevalent in past decades has substantially subsided; yet balancing accounts remain as a significant component in California's regulatory framework governing the electric industry. Consequently, the Commission relies more on administrative procedures than on financial incentives as the principal means of fostering efficient utility operations.

Since volatility in the economy, in the financial markets, and in markets for fuel is considerably less today than in the past, this study recommends that the Commission reexamine the appropriateness of placing greater emphasis on financial incentives to achieve efficiency goals, while relying less on command-and-control regulation. The Commission has tested this approach in varying degrees in the telecommunications and natural gas industries. The time is ripe to explore alternative regulatory mechanisms designed to promote more efficient utility operations in the electric utility industry.

The current regulatory program increases the potential for inefficient investment due to unbalanced incentives governing utility investment decisions.

Utility investment in incremental resource additions, commonly referred to as "resource procurement," cannot be divorced from utility ratemaking. It is in ratemaking where financial incentives and risks lie; and it is to these incentives and risks that the utility ultimately responds when determining whether to invest in infrastructure, and whether to target that investment toward utility-sponsored power plants, energy efficiency, transmission, or power purchased from other providers. Despite this Commission's considerable efforts to ensure efficient utility investment, the incentives the utility faces remain out of balance. This imbalance threatens the Commission's efficiency goals and infrastructure development responsibilities. If left unchanged, that threat will persist.

The utility currently faces substantially different, often biased, incentives when

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free of balancing accounts and rate adjustment mechanisms can in theory encourage efficient utility operations.

choosing among plant construction, energy efficiency measures, or purchased power to meet incremental resource requirements. Under traditional cost-of-service regulation, if the utility constructs a plant, the portion of the capital investment deemed prudent by the Commission is placed in ratebase; that is, the utility recoups its prudent investment plus a fair return. The rate of return is determined by the Commission and is based on returns earned by firms facing comparable financial risk. Many criticize "rate basing" under cost-of-service regulation. Critics assert that a mechanism which allows the utility to earn in direct proportion to the "tonnage of dollars invested,"[225] has little or no relationship to efficient performance.

Until the Commission brought reform to cost-of-service regulation in the 1980s, the utility faced a strong disincentive to invest in energy efficiency. The first reform, the Electric Revenue Adjustment Mechanism, or ERAM, removes the financial risk the utility faces when sales decrease as a result of investment in energy efficiency. Second, the Commission's DSM incentive policy adopted in 1989 helps mitigate the financial bias toward utility-sponsored construction inherent in traditional cost-of-service regulation.

Yet despite the fact that the utility can now profit when it generates electricity or provides more efficient electric service, the earning mechanisms governing the two activities differ markedly. Utility earnings from plant construction are based on the *amount* prudently invested. Commission policy governing utility investment in energy efficiency ties earnings to the utility's *success* in saving energy. Moreover, the amount the utility actually earns from successful DSM activities depends on the *value of the energy saved* as reflected in the cost the utility avoids by using resources more efficiently rather than building more plants and generating more electricity.

So while utility earnings from capital directed toward plant construction continue to

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[225] See Page, Wall Street Journal, op. cit.

depend on the traditional risk-reward relationship, financial incentives governing investment in energy efficiency look to standards of performance and replace strict notions of risk and reward with methods more closely tied to the value of energy service. Given this difference, it remains unclear whether the incentives the utility faces under the respective approaches strike the balance necessary to ensure efficient utility investment.

The utility faces yet another set of incentives when considering the option of investing in power contracts with other utilities and other service providers. As discussed in Chapter VI, the financial risks and incentives associated with power purchases not only differ significantly from those governing investments in power plants and energy efficiency, but they are asymmetric as well.

For example, should the utility invest in the purchase of power, the investment is neither allowed in the utility's rate base, as would be the case for investments made in a new power plant, nor is the investment subject to the type of performance-based incentives that currently apply to energy efficiency investments. Instead, if the utility invests in a power purchase and the Commission decides *ex post* that the investment was prudent, the utility recoups the cost of the purchase--no more and no less.[226] However, if the Commission finds that some portion or all of the power purchase was imprudent, the utility shareholders bear the full cost of the Commission's finding. The asymmetry lies in the fact that the current framework includes a regulatory standard for power purchases in which the utility may suffer financial penalties, but includes no comparable standard entitling the utility to financial rewards for "better than expected" performance on the part of management. A similar asymmetry exists under current ratemaking practices for utility expenses incurred when it

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226 To the extent the cost of purchasing power falls below the utility's cost of producing the power itself, than ratepayers benefit through lower rates. Arguably, the utility also benefits since lower rates reduce the threat of bypass and loss of market share. The utility's behavior, though certainly influenced by these considerations, is likely to be driven to a considerably greater degree by the "bottom line."

constructs power plants

In short, each of the investment options available to the utility--plant construction, purchased power, and energy efficiency--are subject to different ratemaking treatments. As a consequence, each option offers the utility distinct and sometimes conflicting financial risks and incentives.

This study concludes that these differences continue to threaten the Commission's goal of efficient utility investment. Moreover, these differences in treatment, the incentives they pose for the utility when choosing among resource options, and the type of utility behavior these differences engender can foster continued disagreements, excessive litigation, and gridlock among the many legitimate interests with a stake in utility resource procurement.

This study therefore recommends that the Commission examine options to reform both resource procurement and ratemaking with the intent of striking a more appropriate balance among the incentives the utility faces in the decision to construct facilities, purchase power, or use energy more efficiently. That reform should address the link between financial risks and incentives that come with ratemaking and utility investment in incremental resources.

The current regulatory program requires a multiplicity of complex proceedings, which increase costs and threaten the quality of public participation and Commission decision making.

As discussed elsewhere in this study, the state's current regulatory program governing the electric industry is in many ways a by-product of conditions and circumstances which no longer persist. In the decades preceding the Energy Crisis and the economically-troubled 1970s and early 1980s, the utilities' monopoly position was strong; productivity and sales were on the rise; and inflation and fuel costs were low. In response to these favorable conditions, regulation was simple and regulatory proceedings were few and relatively noncontroversial.

But with the 1970s came the Energy Crisis; lagging electric sales and utility productivity; soaring fuel prices; skyrocketing inflation and interest rates; and seemingly uncontrollable utility operating and construction costs. During this era, many utilities watched revenues dwindle, while regulators and consumers watched the cost of electric service increase substantially.

With the changing times came a different regulatory approach. With the financial health of the state's utilities in question, and concerns for environmental quality on the rise, this Commission, like many others across the country, abandoned "light-handed" regulation, opting instead for greater partnership in utility decisions governing operation and investment--a role the utility in some cases called for and welcomed given the difficult challenges of the time.[227]

The move to a more intrusive regulatory approach brought with it certain trade- offs. In particular, this new partnership, in which the Commission figures significantly in utility management decisions, required adding numerous regulatory proceedings to the traditional cost-of-service framework. These additional proceedings venture broadly into utility activities, from general operations to the particulars of incremental resource procurement. The proceedings, which took the form of balancing accounts, rate adjustment mechanisms, and the complex review by this Commission and the California Energy Commission of utility resource procurement, increased the administrative cost of regulating the electric industry and the resources required for the Commission to perform adequately its regulatory obligations and responsibilities. Moreover, the introduction of several balancing accounts forced the Commission to rely increasingly on *ex post* reviews of the "reasonableness" of utility actions, further increasing both the cost of regulation and the Commission's role as partner in utility

227 See Barkovich, B., Regulatory Interventionism in the Utility Industry, for a rigorous review of the transition toward "regulatory interventionism" in California's electric industry.

management decisions.

The conditions under which California's light-handed regulatory approach evolved to one based increasingly on extensive regulatory intervention no longer persist. Yet the majority of the mechanisms designed to manage the challenges of that period, and the additional regulatory costs of those mechanisms, remain with us today. Those costs are ultimately borne by the consumers of electric services through increased rates. Those consumers include small and large businesses, whose competitiveness may significantly depend on the cost of electricity bills.

This study recommends that the Commission examine ways to reduce regulatory costs by ensuring that the Commission's regulatory procedures better reflect the conditions facing the industry. The current regulatory framework, including the state's resource procurement approach, corresponds more to the conditions the industry confronted two decades ago than to the those it confronts today or is likely to face in the future. As a consequence, the administrative cost and burden of regulating the electric industry is too high.

The state's current set of regulatory procedures pose still other problems. For example, current oversight of utility activities is highly disaggregated among general rate cases, balancing accounts, utility-initiated applications, and oversight of utility resource procurement. Apart from the high administrative cost this disaggregation engenders, the current array of procedures and proceedings also threaten the quality of regulatory outcomes.

This threat arises principally from the mounting number of Commission decisions that has accompanied the historic growth of proceedings and procedures, and from the increased likelihood of inconsistencies among those proceedings. As the number of proceedings increases, so too does the likelihood that the Commission's resources may fall short of the amount necessary to scrutinize the effect any single decision may have on other areas of utility operations and investment, the workings of the industry generally, or the Commission's goals for the industry. Disaggregation also jeopardizes consistency in assumptions and information used in various proceedings, further threatening the quality of regulatory outcomes.

Finally, the administrative costs of the current regulatory program threaten the quality of public participation. The Commission has aggressive intervenor funding policies. Those policies are designed to compensate participants who make a substantial contribution to Commission actions. Nevertheless, the resources required to participate when important and interrelated policy and implementation issues are fragmented across several formal proceedings can hinder public participation. The problem is particularly acute for those with a legitimate interest but who also face financial hardship.

For each of these reasons, our study concludes that the Commission should exercise its discretion and responsibilities to reform electric regulation, with an emphasis on streamlining and reducing the cost of the administrative procedures governing the industry.

The currently regulatory program offers utility management limited incentives and flexibility to respond to competitive pressures.

Competition in the wholesale market for electric service has increased markedly since the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978. Recent passage of the Energy Policy Act of 1992, particularly with respect to reform of federal transmission policy and the Public Utility Holding Company Act, is expected to broaden and intensify wholesale competition. Moreover, the economic, technological, legal, and regulatory events that fostered wholesale competition have influenced the delivery of energy services delivered at the *retail* level. And while retail competitive conditions are considerably less well developed, this study concludes that the trends discussed in Chapter VII will likely increase the pressure to expand retail competition and consumer choice. Despite these developments, California is not optimally positioned to adapt to and benefit from an increasingly competitive market for energy services.

Voluntary wholesale power exchanges among California's utilities, and utilities throughout the West, have been a common occurrence. More recently, Commission policies implementing PURPA, along with other events, helped foster competition in the West's wholesale power market. This western power market will continue to evolve due to events external to this Commission--such as the Energy Policy Act of 1992.

As in wholesale markets, competition and choice at the *retail* level in California's electric services market will be influenced by Commission policies, as well as events unrelated to Commission actions. This study identifies a number of future trends which may increase the pressure for greater competition, enhanced consumer choice, and the transmission services necessary to accommodate that choice (see Chapter VII).[228] Not an insignificant number of these trends identified occur outside the scope of this Commission's decision making authority and influence. Those trends are likely to increase both the scope and rate at which consumer choice emerges in the electric industry. But this phenomenon is not new. Regulators have had similar experiences in the telecommunications and natural gas industries.

Yet while most agree--some more reluctantly than others--that the future is likely to bring more competition to the industry, the state's current regulatory framework is ill-suited to respond to the changes one can expect as the industry becomes increasingly competitive.

The reason has to do with the weak incentives contemporary cost-of-service regulation offers utilities to operate and invest efficiently. These weak incentives, and the monopoly franchise historically enjoyed by California's utilities, tend to foster an environment in which the utility develops and puts to use skills that differ considerably from those on

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[228] Advocates often characterize retail wheeling as the transmission service best suited to foster competition in the electric industry by offering consumers the opportunity to choose among service providers. Others see retail wheeling as a policy option that brings with it serious technical, economic, and legal issues.

which firms operating in an intensely competitive market must rely. As a result, the current regulatory framework leaves the utilities only moderately equipped to prepare for a more competitive future.

Second, contemporary regulatory tools provide the utility and regulators with limited flexibility to respond aggressively to a market-oriented environment. For example, under cost-of-service regulation, rates are set based on the utility's embedded cost of delivering service. With utility rates hovering above the cost of nonutility alternatives, customers increasingly look elsewhere for services. Recognizing this growing threat of uneconomic bypass and cost-of-service regulation's contribution to that threat, the Commission established pricing policies designed to help the utility compete and discourage consumer choices that frustrate the efficient use of resources.

Reinstating the flexibility previously granted to the utility to deviate from embedded cost prices would likely be overshadowed by the intrusiveness and inflexibility of the current regulatory framework as a whole.[229] As a result, it is unclear whether reviving the Commission's special contract policy alone would allow the utility to respond effectively to today's competitive pressures, or if that policy would offer the utility the incentives and the means needed to prepare for tomorrow's more competitive world.

In addition, though reinstating the policy might aid utility competitiveness, it may *not* enhance utility efficiency. The Commission's policy allowed the utility to discount rates to customers threatening to leave the system, provided the rate did not fall below the utility's marginal cost. Since the utility recovered lost revenues due to rate discounts by raising rates for remaining customers, the utility faced a weak incentive to negotiate special rates based on the customer's willingness to pay for service. The weakness of the incentive threatens

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[229] See Chapter V for a detailed discussion of the Commission's special contract policy. That policy was discontinued in 1990.

efficient pricing.[230]

Finally, allowing the utility to increase rates in order to recoup the revenues lost as a result of special contracts shifts the financial risk of competition away from utility shareholders and places it squarely with consumers.

Another area where incompatibility between the market and current regulation can be seen is in the area of new resource procurement. Chapter V documents how the state's approach resulted in a process that attempts to gauge through an administrative process "what the utility would do." This approach, while appropriate to the challenges of the 1970s and '80s, now imposes an interventionist government planning regime on utility managers, hindering the utility's ability to respond to the changing market for electric service.

For the reasons discussed above, this study recommends that the Commission reform regulation in order to: 1) provide the utility with greater incentives to develop and implement the strategies necessary to succeed in a competitive environment; 2) increase utility flexibility to respond to increased competition; 3) provide regulatory flexibility in a way that encourages efficient operation and pricing; and, 4) ensure that the flexibility the utility currently enjoys, and any additional flexibility granted, does not disproportionately shift the risk of increased competition to consumers.

The current regulatory program impedes the Commission's effort to enhance competition in the electric services industry.

Traditional cost-of-service regulation in the electric industry is the product of a regulatory compact founded on two basic premises: First, with respect to electric services, society's interests were believed to be best served by granting service rights to a single

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230 This is noted without ignoring the fact that consumers may prefer to pay for discounts to prevent bypass rather than pay the higher rates they would face if large consumers were to leave the system altogether.

monopoly. Second, granting monopoly service meant government would oversee the firm's activities in order to protect consumers from the potential abuse of economic power that comes with granting monopoly status.[231]

In return for franchise rights and a reasonable opportunity to earn a fair return on investment, the utility provides nondiscriminatory service within its designated service area. Under this compact, this Commission retains the responsibility of ensuring that the utility provides consumers with safe and reliable service at just and reasonable rates.

Legislators, the courts, and regulators established the compact's basic tenets and the means devised to uphold it at time when vertically-integrated monopolies dominated the structure of the electric industry. Regulatory programs were designed with the intent of overseeing utility costs and securing equitable treatment for its customers.

When viewed historically, competition is a rather recent arrival to the electric services industry. Its introduction and proliferation have brought significant and lasting changes; but in many respects, neither the compact nor the state's regulatory programs have kept pace with those changes. As a result, the state finds itself in the midst of a transition, with: an electric industry increasingly shaped by competition; a regulatory philosophy that embraces competition and market-oriented approaches; and a regulatory compact originally designed to *prevent* competition and oversee natural monopolies.

Recognizing this incompatibility, the Commission has taken steps to bridge the gap between command-and-control regulation and increased competition. Commission policies governing competitive procurement and special contracts represent two such steps. Moreover, the Commission's principal strategy has focused on creating a "level playing field" on which service providers compete fairly for a place in the utility resource plan. But incompatibility persists despite these efforts, skewing the playing field and frustrating

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231 See Chapter II.

attempts to foster competition within the industry. If allowed to continue, the incompatibility between regulation and the industry will worsen as competition mounts. This study identifies several sources of the incompatibility. For example:

- o The utility must provide service to all consumers and incur the costs that obligation brings with it. Nonutility competitors do not face comparable obligations.
- o A significant portion of the utility's expenses are subject to balancing accounts, thereby shielding the utility from certain financial risks. Comparable regulatory mechanisms do not apply to nonutility service providers.
- o The regulatory compact guarantees the utility a reasonable opportunity to earn a fair return on investment; the compact offers no comparable guarantee to nonutility providers.
- o Under the current regulatory regime the state exercises considerable scrutiny over the utility's capital structure; the Commission applies no such scrutiny to the capital structure of nonutility service providers.
- o Utilities can turn to the regulatory process for rate relief; nonutility competitors cannot.

These policies can significantly affect the cost of developing and delivering electric services. To the extent they do not apply uniformly to all competitors, these policies may skew the playing field and inappropriately distort the competitive position of utility and nonutility providers alike.

And the playing field is slanted in yet another way. Over the years, utility activities have evolved to include programs designed to achieve important societal objectives. Today, the utility assists low-income consumers by providing discounts on electric rates and the cost of installing energy efficiency measures. Other utility rates help encourage agricultural development and the economic revitalization of California's urban centers. In addition, the utility maintains regional offices to help ease the administrative burden some consumers may face paying their electric bill. More recently, decision makers have begun to reexamine the need to return the utility to its more traditional role of principal architect and custodian of important infrastructure. Considerable interest has been expressed, for example, in expanding electric utility activities to include the development of low emission vehicles, electric rail, and telecommunications. Indeed, utilities sought and received approval from this Commission to develop both low emission vehicles and the infrastructure required to support their penetration and use in the market. Utilities are now actively engaged in these activities.

These are worthy and important activities, and few deny their benefits. The majority of these programs enjoy a fairly broad base of support, while a relatively small number remain controversial. Utility involvement in some of these programs is voluntary. Involvement in others come as the result of legislation and/or explicit Commission policy.

But in the same way the asymmetric application of regulatory policies can erode a service provider's competitive position, so too, can the cost of programs designed to achieve broader societal objectives--equity among consumers, enhanced economic development, and expanded transportation/telecommunication infrastructure--hamper a provider's ability to compete. Since the regulated utility alone bears the responsibility and cost of pursuing certain programs mandated by government, it is the utility's costs that rise, and the utility's competitive position and market share that is affected by engaging in these activities.

The emerging competitive threat the utility may feel as a result of these programs illustrates the tensions that accompany a regulatory compact whose roots lay in the oversight of natural monopolies and an electric industry entering the competitive arena. When the state of the technology offered consumers few alternatives to utility-sponsored electric service, and when the utility's monopoly position was secure, the costs of these programs were more easily and equitably spread across a broad base of consumers. But as consumers enjoy greater choice among service providers and as the utility's monopoly position erodes, it is increasingly difficult to allocate these costs to utility customers who can leave the system for cheaper, though not always more efficient, alternatives.

In sum, the asymmetric application of regulatory policies poses several difficulties. First, to the extent the Commission deems it appropriate to continue to pursue policies designed to foster a competitive market for electric services, asymmetries of the sort described above will distort that market and frustrate its development. Second, if, as this study projects, the future brings increased competition and consumer choice to the electric industry, maintaining asymmetric regulatory policies will position the state poorly for the changes the industry will undoubtedly face. And if increased competition and choice further constrains the Commission's ability to allocate the costs of providing mandated programs across all customers, customers for whom the utility represents the sole source of electric service--so-called "captive utility customers"--will bear an increased burden of funding those programs. As is the case in the telecommunications and natural gas industry, captive customers tend to be residential customers.

Other Criteria Guiding Strategy Development

The reasons for reform cited in the preceding section focus on the importance and difficulty of maintaining a regulatory framework which achieves several goals simultaneously. Those discussed above include a) ensuring efficient operation and investment; b) minimizing administrative costs; c) maintaining the integrity and quality of public participation and Commission decision making; d) providing the utility with adequate flexibility to price services efficiently and respond to changes in the industry; and e) enhancing competition in the development and delivery of electric services.

There remain other important goals to consider when assessing any strategy to reform regulation of the electric industry, however. Some are goals this Commission has always pursued and will continue to pursue. Others will endure but circumstances may persuade the Commission to modify the means by which it achieves them. And still other goals represent more recent arrivals to the Commission's list of duties and obligations.

CHAPTER VIII

Consumer Protection

Protecting the state's consumers of electric services is one of the Commission's principal and most enduring responsibilities. Under the traditional regulatory compact, government grants the utility monopoly status, allowing it to serve as the sole provider of retail service. Economic theory and observation have shown that absent government oversight, monopoly firms tend to maximize profits. They do so by providing less service and charging a higher price than would be the case in a competitive environment. In addition to constraining output, the monopoly firm has little incentive to ensure the quality of services provided.

The traditional regulatory compact places with the Commission the obligation to protect consumers from the potential for harm--commonly referred to as "monopoly abuse"--that arises when a single firm is granted an exclusive retail franchise. Any reform strategy must provide the Commission with the means necessary and appropriate to guard against unlawful discrimination by the utility.

Much has been said of competition in this study; the introduction of market forces into what was once an industry characterized by strong monopolies has significant implications for consumer protection and the Commission's obligations and duties. The need for rigorous consumer protection will not wane with the rise of increased competition and greater consumer choice. Despite the emergence of a more competitive electric services industry, the utility will for the foreseeable future likely retain its monopoly control of the transmission and distribution system.

As market forces continue to develop in the industry, the Commission will confront additional issues related to consumer protection. For instance, as competition and choice begin to expand, those customers endowed with relatively greater and more sophisticated resources stand to benefit more than others. Equity among consumers has always been one of the Commission's fundamental obligations. Ensuring that the benefits of a more competitive market place accrue equitably to all consumers is likely to continue as a vital Commission objective.

The Commission's role as consumer protector will expand still further in a competitive environment. Historically, consumer protection under the regulatory compact focused on the prevention of monopoly abuse. Competition will require the Commission to protect consumers by maintaining the integrity of the marketplace. In short, the Commission takes on the expanded role of "referee," ensuring that no party engages in anticompetitive behavior. Antitrust concerns will heighten if, as most suspect, the utility actively participates in the energy services market of the future. The Commission will have to address these concerns in the context of its responsibilities related to consumer protection.

Environmental Quality and Resource Diversity

Environmental Quality

The last two decades have seen the Commission's role emphasized and its responsibility broadened in the area of environmental quality and resource diversity. This increased focus stems principally from the passage of landmark environmental legislation, including the California Environmental Quality Act (CEQA); the National Environmental Protection Act of 1969 (NEPA); the Federal Clean Air Act; and more recently, the 1990 Federal Clean Air Act Amendments. The passage of important environmental laws governing the environmental impacts of air and water pollution and hazardous materials have further focused public attention and government efforts on environmental quality. Recently for example, this Commission built on policy guidance from the Legislature to develop innovative methods of explicitly valuing the costs and benefits to the environment of air emissions for the purpose of calculating the cost-effectiveness of energy resources in long-term resource planning and acquisition.[232] Several states across the country have implemented similar policies.

Though the task is difficult, and while no methodology enjoys unanimous support in California or across the nation, most recognize that if done correctly, incorporating environmental costs and benefits in resource procurement can help achieve several goals. These include minimizing the total cost of providing energy service; helping level the playing field among competing resource technologies; and maintaining or enhancing environmental quality.

Given the deteriorating status of California's air quality, the Commission has to date focused its efforts on valuing the costs and benefits of emissions related to the production of energy services; the Commission has stated its intent to expand those values to include water and land use impacts.

The Commission also oversees utility activities related to the disposal and clean-up of hazardous materials. In 1991, the Commission initiated an investigation to examine the potential health effects of Electric and Magnetic Fields (EMF) produced by utility facilities. The goal of the investigation is to determine the need for research, public education and mitigation strategies to respond to public concerns. Finally, as the state's nuclear power plants near the end of their useful lives, the utilities and the Commission will face a host of unique environmental costs and challenges.

These examples illustrate the importance of and the Commission's commitment to addressing environmental impacts in the utility's day-to-day operations as well as in long-term investment decisions. This commitment reflects California's continuing leadership in the development of environmental policy and technology. The Governor has continued that leadership by forming the California Environmental Technology Partnership, whose goal

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232 See P.U. Code 701.1 and Decisions 91-06-022 and 92-04-045.

includes capturing the economic benefits of California's foresight by creating markets for environmental technologies developed and manufactured in California.

Regulatory strategies must continue to provide the Commission with methods to ensure that environmental impacts related to the development and delivery of electric service are minimized in a cost-effective manner. Where appropriate those strategies should attempt to improve those methods.

Resource Diversity

The oil supply disruptions of the 1970s and 1980s taught many the importance of maintaining an electric services infrastructure composed of diverse energy resources. Prior to the disruptions, California's infrastructure depended greatly on fossil fuel for the delivery of services. Consequently, the risk of severe rate increases due to a significant disruption were great. When the disruptions occurred, the rates paid by the state's consumers of investor-owned electric utility services increased substantially.

Since that time, the utility and the Commission have worked together to increase diversity on the utilities' systems and reduce the risk of sudden price increases. Those efforts have been successful, but debate over the appropriate level of diversity continues. In 1991, the Legislature expressed additional support for diversity, directing that until the value of diversity is quantified "...a specific portion of future electrical generating capacity needed for California be reserved or set aside for renewable resources."[233] Each of the state's IOUs will be soliciting bids for renewable resources in upcoming competitive auctions.

Strategies to reform regulation of the electric industry should build on the lessons from the past and ensure that resource diversity is considered explicitly in long-term resource procurement decisions.

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[233] P.U. Code section 701.3.

CHAPTER VIII

Safety and Reliability

The Commission continues to have responsibility for the safety of utility facilities and services. It establishes standards for utility system design and construction that protect utility customers and employees from unsafe facilities or conditions. This is now and will always be a paramount concern for the Commission.

Maintaining a reliable system for supplying electricity to consumers has also been a fundamental function of electric utility regulation. During the first three-quarters of the twentieth century electricity demand increased dramatically at least partly because it was a reliable source of energy. It was seen as both an economical and dependable fuel source for manufacturing, commercial, and public lighting uses, as well as residential heating, cooling, cooking, and lighting. Public utility commissions were reluctant to do anything that might reduce the reliability of electricity as an energy source.

As discussed in Chapters IV and V, electric system reliability is sensitive to both global and local economic conditions and regulatory policies. Lengthy regulatory proceedings can delay new generating facilities and undermine system reliability.

Clearly, any modifications to the existing regulatory structure should degrade the reliability of California's electric system. Given the competitive alternatives which now exist, utilities should be encouraged to actually improve reliability so that customers requiring such security could be persuaded to locate new facilities in California and retain existing facilities in the state.

Safety and reliability must remain as important components in any utility strategy.

Regulation and the Pursuit of Social Objectives

There has been much discussion in this report about utility programs designed to achieve important social objectives. These include, among others, programs for low-income customers; rates designed to spur agricultural development; and rates to foster low-emission vehicle development and use.

The Commission has mandated some of these programs, while others have been mandated by the Legislature. Still others, such as low-emission vehicle programs, resulted from Commission approval of specific utility requests.

As the future brings increased competition to the utility industry, and as commercial and industrial customers face a growing number of global competitors in the market for goods and services, the Commission will face considerable challenges in the effort to equitably allocate the costs associated with these valuable programs among customers.

In considering regulatory reform strategies, the Commission must strike a balance between funding programs designed to pursue social objectives and the effects of allocating the costs of such programs across utility rates in a more competitive environment.

General Approach Used in Developing Reform Strategies

The regulatory reform strategies offered for discussion as part of this study have been crafted to address the shortcomings of the current regulatory framework listed above. Those problems form the basis of this study's recommendation that the Commission make reform of the electric industry a priority. The strategies were also crafted keeping in mind other important Commission goals, including ratepayer protection, environmental quality, and system reliability.

But even if all of the state's varied interests were to agree with the problems identified and the criteria discussed in this study, there is no guarantee that a comparable consensus would be reached regarding the form and content of an appropriate reform strategy. This should come as no surprise. One's preferred strategy is justifiably influenced by one's priorities and values. As such, once agreement has been reached among parties with respect to the problems that need to be solved, and the goals that ought to be achieved, these same parties may devise a variety of different strategies, each reflecting their own specific priorities.

In short, there is undoubtedly a considerable number of potential strategies from which to choose to solve the problems and achieve the goals discussed in this study. But each requires making trade-offs. For example, the Commission could adopt a regulatory strategy designed to ensure above all things that the utility system operates with absolute reliability, imposing high penalties for a single disruption of service. The cost of doing so would likely be exorbitant, however, leading to inefficient investment and higher prices.

The fact that such balancing occurs is often taken for granted, but its importance in the decision making process cannot be overlooked. Accordingly, the study assesses the trade-offs inherent in each of the proposed strategies. It does not, however, impose a hierarchy of criteria. Instead, each of the strategies is crafted keeping in mind the need to address *each* of the many goals the Commission must ultimately balance, and each of the problems identified. The assessment therefore describes qualitatively how each strategy addresses those goals. The final balancing is left for the Commissioners to strike, in consultation with interested parties.

The strategies are designed to allow considerable flexibility in the Commission's effort to strike that balance. Each is a unique strategy, and is crafted recognizing the competitive pressures the industry faces. Each could be adopted independently of the others. Alternatively, the Commission could decide that an appropriate strategy is one which combines elements from two or more strategies. Finally, these strategies could also be viewed as a progression, with each strategy representing a step in the transition toward a restructured electric industry characterized by greater competition and enhanced customer choice.

In addition to the considerations described above, several general principles also guided the development of the strategies. They attempt to ensure that each strategy:

- **Modifies the regulatory compact and/or the means employed to uphold the compact when appropriate;**

- **Clearly defines the compact's obligations and privileges under each strategy;**

- **Replaces command-and-control regulation with market-based performance targets when appropriate;**

- **Creates less intrusive regulation by setting clearly articulated goals and policies, providing the utility with adequate flexibility to achieve those goals, and establishing utility accountability commensurate with the degree of flexibility provided; and,**

- **Ensures that the incentives facing the utility reinforce rather than frustrate the achievement of regulatory and other state goals.**

What follows are descriptions of the four strategies developed for this report. Included is an assessment of each strategy, using criteria based on the earlier discussions in this chapter. Also included is a chart summarizing the assessments for each of the strategies (Figure VIII-1).

Figure VIII-1
Comparison Among Current Framework and Reform Strategies

	Strategy A Limited Reform	**Strategy B Price Caps**	**Strategy C Limited Customer Choice**	**Strategy D Restructured Utility Industry**
Administrative Costs and Burdens	Reduced regulatory burden after initial implementation	Significantly reduced after initial implementation	Significantly reduced after initial implementation	Significantly reduced after initial implementation
Consumer Protection	Comparable	Redefined through ceiling and floor prices, shareholders gain from improved efficiency	Comparable for core, non-core same as Strategy B	Commission role significantly reduced for non-core generation
Efficient Operation and Investment	Modest improvement	Improved incentive to minimize costs	Modest improvement for core, improved incentive to reduce costs for non-core	Improved incentives for cost minimization for core and non-core
Safety and Reliability	Comparable	Absent strong oversight, pressure to minimize cost may compromise safety/reliability	Comparable for core, for non-core same as Strategy B	Absent strong oversight, pressure to minimize cost may compromise safety/reliability
Efficient Pricing	Comparable	Improved incentive to price efficiently	Comparable for core, improved incentive for non-core	Improved incentive for core and non-core
Environmental Quality and Resource Diversity	Comparable	Comparable	Comparable for core, difficult to promote for non-core	Comparable for core, difficult to promote for non-core
Pursuit of Social Objectives	Comparable	Reduced ability to promote objectives	Comparable for core, reduced for non-core	Reduced ability for core and non-core

CHAPTER VIII

<u>The Strategies</u>

Strategy A - LIMITED REFORM

This strategy attempts to achieve greater compatibility between the electric industry and the state's regulatory goals through specific and limited adjustments to the current regulatory framework.

<u>Industry Structure</u>

- **The utility remains a full-service, vertically integrated company, providing generation, demand-side, transmission, and distribution services.**

  Nonutility providers compete for a place in the utility resource plan.

  The utility procures *all* incremental resource requirements--both supply-side and demand-side--through competitive acquisition subject to the competitive resource procurement principles described below.

  The utility retains ownership of its transmission and distribution facilities.

  The development of policies governing a) pricing of transmission services and b) access to utility-owned transmission facilities continues as part of the Commission's current transmission investigation, subject to policy guidance from the Legislature and the federal government.

<u>Ratemaking</u>

- **Cost-of-service ratemaking principles are retained.**

- **Rate cases are conducted annually.**

  Balancing accounts governing nonfuel-related expenses, and rate adjustment

mechanisms are eliminated. (These include ECAC, MAAC, attrition proceedings, and rate design windows.)

Annual rate cases obviate the need for additional proceedings designed to adjust utility rates and revenue.

The Electric Revenue Adjustment Mechanism (ERAM) is retained.

The bias embodied in traditional cost-of-service regulation toward increased electric sales at the expense of cost-effective energy efficiency measures favors retaining ERAM.

The Energy Cost Adjustment Clause (ECAC) is replaced with a market-based performance standard for natural gas purchased by the utility for electric generation. Prudence reviews for natural gas purchases are eliminated.

The performance standard is designed to provide the utility with a greater incentive to minimize the cost of natural gas and natural gas transportation than is currently embodied in the ECAC.

The standard could be composed using price indices for the various natural gas supply basins, and an appropriate "proxy price" for transportation. To the extent the utility procures gas for less than the performance standard, the utility would benefit by an amount equal to the difference between the standard and the actual purchase price; the utility would be penalized by the amount the purchase exceeds the standard. The reward/penalty zone should be symmetric around the performance standard.

An additional zone could be established within which benefits (and costs) could be shared between the utility and consumers. This performance mechanism closely resembles that used in the new regulatory framework governing the telecommunications industry in California.

Eventually, the Commission may find that performance standards can be used for all utility fuel and wholesale purchase decisions.

The Commission continues to determine the utilities' cost-of-capital annually in the consolidated rate case proceeding.

The determination of short-run avoided cost for the purposes of setting payments to qualifying facilities would occur as part of the annual rate case.

The Public Utility Regulatory Policies Act requires that the Commission continue to adopt a value representing the utility's short run avoided cost.

The Commission's policy governing special rate contracts (also referred to as Expedited Application Docket, or EAD) is reinstated.

The utility is granted pricing flexibility to enhance its competitiveness and prevent uneconomic bypass and business flight in the short term.

<u>Resource Procurement</u>

- **The Commission identifies policy goals, and ensures those goals are reflected in the utility resource plan. The Commission approves guidelines for resource procurement that may be developed in a formal proceeding or in a collaborative setting. Resource procurement might consist of the following elements.**

  When the utility determines that it needs to construct facilities, purchase power, or invest in energy efficiency, it files its proposed resource plan with the Commission. The resource plan identifies how the utility proposes to meet the Commission's policy goals. The resource plan is based on the state's forecast of long-term electricity demand. Interested parties have an opportunity to scrutinize the utility's resource plan, after which the Commission renders final approval.

- **The utility faces more balanced earnings incentives for resources purchased, constructed, or saved through energy efficiency.**

Resources are acquired through an auction mechanism. The utility may participate in the auction, but if the utility-proposed project is successful in the auction process, the utility's investment is not placed in ratebase, but is instead governed by a performance-based contract akin to a QF contract. If the utility or its affiliate opts to bid to develop new DSM or new generation, the auction must receive greater regulatory scrutiny.

A ceiling is established, against which the cost of long-term resources other than utility-owned power plants are judged. The ceiling price is set based on the results of the previous auction, plus inflation, minus a productivity factor. If purchased power or demand-side resources are acquired for less than the ceiling price, the savings (the difference between the ceiling price and the actual price paid) is shared between ratepayers and shareholders and the resource acquired is deemed prudent by the Commission.

For short-term purchases, the procurement approach is similar to that governing long-term resources, but the ceiling price is set by the utility's short-run avoided costs. Short-term purchases are those with contract lives of five years or less. Alternatively, short-term purchases can be subject to reasonableness reviews in the annual rate case.

- **Pursuant to P.U. Code 701.1 (c), the utility continues to include in cost-effectiveness calculations related to resource procurement values approved by this Commission for any costs and benefits to the environment, including air quality. In addition, pursuant to P.U. Code 701.3, the utility either uses as part of resource procurement a) a Commission-approved methodology that values fuel diversity, or b) meets a portion of its resource requirement with renewable resources.**

Regulatory Compact

- **The regulatory compact remains unchanged.**

The utility retains its obligation to serve all customers and an exclusive retail franchise within its service territory.

- **Through the changes described above, the means the Commission employs to uphold the compact are modified.**

  Through the use of cost-of-service regulation, the means traditionally used by the Commission to ensure just and reasonable rates for consumers endures. However, the creation of a market-based performance standard governing utility gas purchases related to electric generation, the move to annual rate cases, and the elimination of certain balancing accounts and rate adjustment mechanisms alter the current means by which the Commission provides the utility with a reasonable opportunity to earn a fair rate of return.

Assessment of Strategy A

This strategy attempts to address each of the problems currently facing the industry with few structural changes, relying principally on the current cost-of-service regulatory model. As such, the extent to which this strategy can mediate the rate-cost gap discussed in Chapter VI, or position the state for a more competitive future, is uncertain.

Administrative Costs and Burdens - Initially, administrative costs and burdens will increase in order to develop the fuel price indices. Whether annual rate cases for each electric utility would increase the administrative work load and costs is uncertain, since eliminating balancing accounts, attrition filings, and other annual rate adjustment proceedings for each utility may well offset any increase resulting from annual rate cases. In addition, replacing the Update with a utility-initiated process will significantly reduce administrative costs and burdens to the Commission, the utility, consumers, and interested parties appearing before the Commission.

Consumer Protection - This strategy does not compromise the Commission's current ability to oversee utility activities and protect the interests of the state's consumers. The ratemaking and resource procurement procedures and review processes under this strategy are adequate to ensure nondiscriminatory service and just and reasonable rates.

Efficient Operation and Investment - This strategy brings limited change to the incentives the utility faces for efficient operations and somewhat more balanced incentives for efficient investment.

Setting rates and revenue requirements in the annual rate case retains a cost-of-service framework that ensures that the utility recovers prudently incurred expenses plus a fair return. Incentives to reduce costs remain weak since the link between costs and rates persists. Annual rate cases reduce significantly regulatory lag and the utility's incentive to minimize costs between rate cases. The annual rate case will, however, give the Commission improved oversight over utility costs, which may result in efficiency gains, though improvements in efficiency may be offset if annual rate cases produce additional administrative costs. The market-based performance standard governing natural gas purchases should increase operating efficiency.

The ceiling benchmark established for short- and long-run investment retains the financial incentive to invest in DSM and creates an incentive to pursue cost-effective power purchases. These incentives should provide the utility with a more balanced incentive to invest efficiently.

Safety and Reliability - This strategy threatens neither safety nor reliability relative to the current framework. The Commission retains oversight of utility operations and expenses, ensuring continued safety and reliability of the utility system. Increased flexibility in the resource procurement process (with the potential to respond more quickly to increasing demands on the system) may improve reliability.

Efficient Pricing - This strategy is not likely to increase efficiency in pricing. This option does not call for changes to rate design policy. As such, allocation continues to be governed by the Commission's equal percentage of marginal cost policy (EPMC), while rates continue to approximate class-average marginal costs of service. Customers with options for less expensive service negotiate discounts with the utility. The costs of the discounts are spread across remaining customers, leaving the utility with little incentive to negotiate contracts which reflect the customer's willingness to pay.

Environmental Quality and Resource Diversity - This strategy continues the Commission's careful but deliberate approach to environmental quality and resource diversity. Resource procurement retains the current incentives for acquiring energy efficiency and builds upon efforts to value the environmental effects of different resource options. Under the revised resource procurement approach, the Commission continues to set environmental and resource diversity goals and the utility demonstrates those goals are met.

Pursuit of Social Objectives - Retaining the cost-of-service framework does not threaten the Commission's equity goals since that framework allows the Commission to continue to design rates as it has in the past, preventing discriminatory pricing across customer classes.

Requests, approval, and ratemaking treatment for social objectives remain unchanged under this strategy. None of the strategies offered proposes adding to or eliminating utility programs currently underway. However, it should be noted that increased competition in the industry will make any widening of the rate-cost gap, including any widening due to costs related to these programs, controversial.

Those commercial and industrial customers facing stiff competition, and for whom electricity bills represent a large portion of business expenses, will be increasingly reluctant to share in the cost of these programs through electricity charges. As the gap and competition increase, commercial and industrial customers will look increasingly to nonutility service providers, leaving the utility system for lower-priced alternatives. Depending on the extent of the gap, those customers are likely to go further and increase pressure on the Commission to facilitate access to cheaper alternatives. This strategy, if pursued, may therefore force the Commission to allocate the costs of these programs solely to captive consumers, raising significant equity concerns.

Strategy B - The Price-Cap Model

This strategy continues to embrace the tenets of the traditional regulatory compact, but departs significantly from the current means used by the Commission to uphold the compact. Building on the ratemaking approach adopted as part of the Commission's new regulatory framework governing the telecommunications industry, this option focuses primarily on *increased pricing flexibility and increased accountability for the utility, linking utility earnings to performance rather than expenses. These features are intended to provide the utility with an incentive to operate and price more efficiently, and compete more effectively. The Commission regulates rates rather than utility expenses under this strategy.*

CHAPTER VIII

Industry Structure

- **Like Strategy A, the utility remains a full-service, vertically integrated company, providing generation, demand-side, transmission, and distribution services to all customers.**

  Nonutility providers compete for a place in the utility resource plan.

  The utility procures *all* incremental resource requirements--both supply-side and demand-side--through competitive acquisition subject to the competitive resource procurement principles described below.

  The utility retains ownership of its transmission and distribution facilities.

  The development of policies governing a) pricing of transmission services and b) access to utility-owned transmission facilities continues as part of the Commission's current transmission investigation, subject to policy guidance from the Legislature and the federal government.

Ratemaking

- **Current cost-of-service ratemaking principles are used to establish the initial rate cap. Once the rate is established, cost-of-service ratemaking is abandoned.**

  Utility costs are allocated among customers based on the Commission's Equal Percentage of Marginal Cost (EPMC) policy. Rates are based on current rate design policies. The initial proceeding establishing the rate cap may also examine the need to further disaggregate customer classes based on marginal costs to encourage greater pricing efficiency.

  The utility is granted flexibility to negotiate prices with individual customers. Those prices may not exceed the cap determined in the initial implementing proceeding and may not fall below the utility's marginal cost.

Rate Changes

The utility has the opportunity to adjust rates annually through an advice letter filing. Rates are only adjusted to reflect changes in productivity, inflation, and other factors which the utility cannot influence, but which have an effect on the cost of providing service. The productivity rate is set as part of the initial implementation proceeding. Actual inflation, and indices accounting for costs which the utility cannot control, are included in the price indexing formula corresponding to the year in which the changes are observed.

Utility Earnings

The initial proceeding implementing this strategy determines a reasonable rate of return for the utility under the modified ratemaking regime.

Using the Commission-approved rate of return as a benchmark, the utility retains earnings which exceed the benchmark rate of return up to a prespecified threshold. Earnings which exceed the prespecified level are shared between the utility and consumers.

The zone governing earnings is symmetric around the rate of return benchmark; that is, the utility also absorbs any losses up to a specified level in the event utility earnings fall short of the rate of return benchmark. Losses in excess of the "loss cap" are shared between consumers and the utility.

This element of the performance mechanism also closely resembles that used in the new regulatory framework governing the telecommunications industry in California.

- **Rate cases are eliminated.**

The price indexing mechanism breaks the link between utility rates and expenses, eliminating the need for traditional rate cases.

Three years after implementing the price-cap framework, the Commission reexamines the overall framework, including rates customers face, the reasonableness of the productivity index used in the pricing formula, and utility earnings.

Balancing accounts governing nonfuel-related expenses as well as rate adjustment mechanisms are eliminated. (These include ECAC, MAAC, ERAM, attrition proceedings, and rate design windows.)

Regulation of utility rates rather than revenue requirements also removes the need for proceedings designed to adjust utility rates and revenue.

The determination of short-run avoided cost for the purposes of setting payments to qualifying facilities would occur as part of a separate proceeding.

The Public Utility Regulatory Policies Act requires that the Commission continue to approve the utility's short-run avoided cost.

- **Reasonableness reviews are eliminated.**

Resource Procurement

- **Like Strategy A, the Commission identifies policy goals, and ensures those goals are reflected in the utility resource plan. The Commission approves guidelines for resource procurement that may be developed in a formal proceeding or in a collaborative setting. Resource procurement might consist of the following elements.**

When the utility determines that it needs to construct facilities, purchase power, or invest in energy efficiency, it files its proposed resource plan with the Commission. The resource plan identifies how the utility proposes to meet the Commission's policy goals. The resource plan is based on the state's forecast of long-term electricity demand. Interested parties have an opportunity to scrutinize the utility's resource plan, after which the Commission renders final approval.

- **Under the price-cap model, the utility faces somewhat more balanced earnings incentives for resources purchased, constructed, or saved through energy efficiency.**

Resources are acquired through an auction mechanism. The utility may participate in the auction, but if the utility-proposed project is successful in the auction process, the utility's investment is not placed in ratebase. If the utility or its affiliate opts to bid, the auction must receive greater regulatory scrutiny.

Price-cap regulation offers the utility with ample incentives to build and operate plants efficiently. Therefore, expenses related to utility-sponsored plant construction is no longer placed in ratebase under this strategy. Price-cap regulation also gives the utility strong incentives to minimize the costs of power purchases, since it keeps the difference between the purchase price and the sale price.

A ceiling is established, against which the cost of *energy efficiency* **investments are judged. The ceiling price is set based on the results of the most recent auction, plus inflation, minus a productivity factor. If energy efficiency resources are acquired for less than the ceiling price, the savings (the difference between the ceiling price and the actual price paid) is shared between ratepayers and shareholders.**

The price-cap model provides the utility with an overriding financial incentive to reduce costs and increase sales. As such, it provides a strong disincentive to invest in energy efficiency. An additional mechanism is therefore applied to the model to compensate for the powerful incentive the utility faces under this strategy to ignore energy efficiency opportunities. No additional incentive governing purchased power is required since the model provides strong incentive to purchase low-cost power.

- **Pursuant to P.U. Code 701.1 (c), the utility continues to include in cost-effectiveness calculations related to resource procurement values approved by this Commission for any costs and benefits to the environment, including air quality. In addition, pursuant to P.U. Code 701.3, the utility either uses as part of resource procurement a) a Commission-approved methodology that values fuel diversity, or b) meets a portion of its resource requirement with renewable resources.**

Regulatory Compact

- **The regulatory compact remains unchanged.**

  The utility retains its obligation to serve and an exclusive retail franchise within its service territory.

- **Through the changes described above, the means the Commission employs to uphold the compact are modified substantially.**

  Replacing cost-of-service regulation and its associated balancing accounts and rate adjustment mechanisms with the price cap severs the connection between costs and rates. This alters significantly the means traditionally used by the Commission to both ensure just and reasonable rates for consumers and provide the utility with a reasonable opportunity to earn a fair rate of return.

Assessment of Strategy B

Like Strategy A, this strategy makes few changes to industry structure. Unlike Strategy A, however, the price-cap model significantly alters the ratemaking component of regulation. The major advantage of this approach is that it provides incentives for efficient pricing.

Administrative Costs and Burdens - While proponents of price caps promise substantially reduced administrative burdens and costs, the extent of the reduction in the telecommunications industry, where the Commission has already implemented price-cap regulation, is uncertain. The reductions promised stem from replacing currently litigious rate proceedings with the price cap, and the index mechanism used to modify the cap. However, the initial proceedings required to set the price cap and the formula governing price changes may prove quite costly and time-consuming. However, once these fundamental components are established regulatory burdens should be lessened.

Consumer Protection - The price-cap strategy significantly redefines ratepayer protection under the regulatory compact. Traditional cost-of-service ratemaking scrutinizes utility expenses and sets rates at levels which allow the utility to recover Commission-authorized expenses. Under a price-cap approach, the Commission no longer adjusts utility rates to ensure the utility only recovers the cost of providing service. As long as the utility charges rates which do not exceed the authorized price cap(s) or fall below its marginal cost, the utility has complete flexibility to set rates. Moreover, though the utility faces a strong financial incentive to reduce costs under the price cap, the earnings mechanism primarily funnels those efficiencies to shareholders, and does not ensure that ratepayers share in the benefits. As such, the price-cap model departs from basic cost-of-service principles since the Commission no longer sets rates such that the utility earnings are limited to the cost of providing service.

Since the price caps are initially set based on cost-of-service principles, ratepayer protection with respect to curbing utility market power is not compromised; that is, the utility cannot raise rates above a Commission-specified level. Equity with respect to pricing *among* consumers in the same customer class is much less certain, however, since the utility is free under price-cap regulation to negotiate different rates among individual consumers.

Efficient Operation and Investment - The price-cap strategy improves the incentives for efficient utility operation by eliminating the link in cost-of-service ratemaking between utility expenses and rates. This linkage is one of the frequent criticisms of cost-of-service ratemaking. Since rates are only modified as a result of exogenous factors under price-cap regulation, the utility faces increased incentives to minimize costs and operate more efficiently. When rates exceed the utility's cost of providing service, the utility's investors retain the financial reward of improved performance; when the cost of providing service exceeds rates, the utility, and its shareholders, are accountable for the deficit. This relationship between performance and earnings provides utility management with a stronger incentive to minimize operating costs than does the traditional cost-of-service regulatory framework.

The price cap may also improve incentives for efficient utility investment. First, the utility faces more balanced incentives with respect to plant construction and power purchases, since each offers comparable opportunities to earn additional profits due to reductions in the cost of providing service. Whether the shared savings mechanism for energy efficiency compensates for the price cap's strong incentive to increase sales and reduce costs is uncertain. Without the modification, the current incentives for energy efficiency disappear completely, returning the industry to one in which the utility is in the business of developing and delivering a commodity--electrons--rather than a full array of electric *services*. Yet the modification offered here may not be sufficient to balance the overriding incentive to sell electricity.

Safety and Reliability - A common criticism of price-cap regulation is that utilities, facing considerable pressure to minimize costs, may compromise the safety of customers and workers, as well as the reliability of the delivery system. Since the Commission retains its oversight responsibilities with respect to the safety and reliability of utility facilities and operations, price caps may force the Commission to devote considerably more resources to this important regulatory role. Should the Commission adopt a price-cap strategy, the subsequent review process should place particular focus on its effect on safety and reliability.

Efficient Pricing - Strategy B improves pricing efficiency by granting the utility additional flexibility. Cost-of-service ratemaking does not respond well to the threats utilities currently face from customers who enjoy alternatives to utility service. By contrast, price caps offer the utility the flexibility to discount rates to individual customers that may bypass the utility system. Those negotiated rates may not fall below marginal costs. Since under the price-cap strategy the utility bears the burden of revenue shortfalls, there is a strong incentive to negotiate a price equal to the customer's willingness to pay, which promotes more efficient pricing. In addition, under this strategy the Commission does not approve individual rate contracts, which decreases administrative costs and burdens relative to past rate discount policies.

Environmental Quality and Resource Diversity - The resource procurement approach used in the price-cap strategy attempts to retain those elements of the current regulatory system designed to promote environmental quality and resource diversity. Resource procurement retains incentives for utilities to invest in energy efficiency by allowing utilities and ratepayers to share the benefits of energy efficiency. This sharing only exists for energy efficiency, in order to compensate for the sales promotion incentives inherent in a price cap. To the extent the mechanism offered does not compensate adequately, environmental quality and resource diversity may suffer.

The Commission also retains its ability to set environmental and diversity goals for utility resources and purchases. As in each of the strategies offered, utility resource procurement is subject to values adopted by this Commission pursuant to P.U. Code 701.1 (c), and to the requirements of P.U. Code 701.3 with respect to resource diversity. (See the discussion of Environmental Quality and Resource Diversity under Strategy A, above.) The utility must make a showing to the Commission that its procurement has met the environmental and diversity goals and obligations established by the Commission.

Pursuit of Social Objectives - Retaining the cost-of-service framework does not threaten the Commission's equity goals in their entirety, but may have implications in the context of rate differences among like customers in the same customer class. When viewed in the aggregate, rates are capped based on current ratemaking and rate design policies, thereby providing a level of equity among classes comparable to the current level. The flexibility enjoyed by the utility to negotiate different rates among consumers in the same customer class raises questions regarding intra-class equity.

Like Strategy A, requests, approval, and ratemaking treatment for social objectives remain unchanged under the price-cap strategy. And like Strategy A, increased competition in the industry will make any widening of the rate-cost gap, including any widening due to costs related to these programs, controversial. Under the price cap, the utility is likely to resist providing additional programs designed to promote social objectives since prices remain fixed while costs increase as a result of the programs. This resistance may be alleviated if the costs of providing additional programs are included in the indexing formula which allows increases in the price cap. Resistance is likely despite such accommodations, however.

Commercial and industrial customers facing stiff competition, and for whom electricity bills represent a large portion of business expenses, will be increasingly reluctant to share in the cost of these programs through electricity charges. As the gap and competition increase, commercial and industrial customers will look increasingly to nonutility service providers, leaving the utility system for lower-priced alternatives. Depending on the extent of the gap, those customers are likely to go further and increase pressure on the Commission to facilitate access to cheaper alternatives. This strategy may, like Strategy A, force the Commission to allocate the costs of these programs solely to captive consumers, raising significant equity concerns.

CHAPTER VIII

Strategy C: Limited Customer Choice - Core/Non-core

The increasingly competitive market for generation services offers significant savings to certain utility customers. This core/non-core regulatory strategy promotes customer choice through access to the competitive market, while simultaneously protecting the interests of those customers who remain on the utility system. This strategy makes structural changes to the industry that can foster increased competition in the industry. Its design draws from the core/non-core strategy governing the state's natural gas industry.

Industry Structure

- **The utility is required to offer a full range of electric services (generation, transmission, distribution, energy efficiency) to core customers only.**

  Core customers, who lack alternatives or prefer not to participate in the market for electric services, continue to receive reliable services from the utility.

- **The CPUC defines the non-core class. Non-core eligibility might initially depend on customers' energy and capacity requirements. Eligibility should be limited in the initial period, since the Commission and the utility may require time to learn from and adapt to the new structure. All customers are initially classified as core customers; customers who meet the non-core eligibility requirements may elect non-core status.**

  The emerging competitive market for electricity resembles in important ways the natural gas industry of six years ago. Large industrial customers face or wish to have access to alternatives to utility service in order to reduce energy bills. Other customers--mostly residential customers--currently have no alternative to utility electric service.

- **The utility no longer faces an obligation to provide energy and capacity to non-core customers but may compete to serve them. Non-core customers contract**

with the utility or other providers for generation services. The utility must offer transmission and distribution services to non-core customers.

- **Nondiscriminatory transmission access is directly available to non-core customers from the utility.**

As customers contract for their own electricity needs, the level of competition and customer choice in the electric industry is likely to increase. Access to transmission is necessary to allow the competitive market for electricity to flourish. As long as utilities control transmission and distribution, they must wheel power to ensure the success of the core/non-core strategy. ***The initial non-core eligibility requirements limit the number of customers eligible to request retail wheeling.***

<u>Ratemaking</u>

- **As a first step, the Commission establishes a proceeding to allocate the utility's revenue requirement between core and non-core. Cost allocation is based on the utility's long-run marginal cost of providing service. Any revenue requirement, or "residual costs," left as a result of using marginal cost-based principles may be allocated (and recovered) in one of three ways : 1) Residual costs are allocated between both core and non-core classes. For the core class, residual costs are treated according to the modified cost-of-service framework under Strategy A. For the non-core, costs may be recovered through exit fees levied on customers electing non-core status, increased sales, or both; 2) residual costs are collected through a levy placed on transmission service and collected from all customers, core and non-core alike; or 3) some combination of options 1 and 2.**

Separating the utility's revenue requirement between the core and non-core classes is intended to allow the utility to compete more effectively for non-core customers. In return, the mechanism prevents the core from being forced to contribute to any revenue shortfalls the utility incurs on the non-core side once the initial allocation has been accomplished. Instead, the utility and its shareholders are fully accountable for recovering costs allocated to the non-core class.

- **The utility enjoys pricing flexibility and may negotiate discounted rate contracts with non-core customers. Discounted rates are limited by a ceiling, which is the tariffed rate based on class-average LRMC, and a price floor based on customer-specific LRMC. This mechanism closely resembles the mechanism offered as part of the price-cap strategy (Strategy B).**

  The Commission sets price ceilings to prevent the utility from exercising market power and floors to prevent the utility from pricing inefficiently (i.e., below marginal cost).

  Non-core customers who do not negotiate discounts will be served at the otherwise applicable tariff rate. The utilities will have strong incentives to negotiate appropriate discounts, since non-core tariff rates will increase to cover the costs of discounts, potentially increasing the viability of bypass for more non-core customers.

- **Rate-making and rate design for the core class are subject to the modified cost of service framework offered in Strategy A.**

- **Once set, utility rates for non-core service may only change in a triennial proceeding established as part of this strategy. Rate cases and balancing accounts are eliminated for the utility's non-core operations, leaving the utility and its shareholders fully accountable for recovering its non-core revenue requirement.**

  With increased flexibility to compete, and the potential for greater financial rewards, it is appropriate for the utility and its shareholders to bear the risks that accompany those changes. On the non-core side, utility shareholders are accountable for any revenue surplus or shortage within a specified band around the authorized rate of return. If the rate of return falls outside the specified band, surpluses and shortages will be shared with non-core customers. This mechanism is similar to that used in the telecommunications regulatory framework.

Three-year cycles offer sufficient time to determine whether estimates of the utility's revenue requirement are accurate and the allocation between core and non-core classes appropriate. This proceeding should further examine the success and effectiveness of transmission service provided to non-core customers by the utility. In addition, these proceedings might also examine the need to offer core customers who meet the non-core eligibility requirements another opportunity to elect non-core status, as well as the desirability of broadening the eligibility requirements.

- **Having voluntarily elected non-core status, customers may not switch from non-core to core between triennial rate proceedings.**

  Utilities must plan sufficient resources to serve the core load. If non-core customers return to core service, the costs of re-entry should reflect the costs of serving incremental core load.

- **The terms and conditions of transmission and distribution services are governed by Commission and FERC policies.**

  The Federal Energy Regulatory Commission enjoys exclusive jurisdiction of the terms and conditions of transmission service. Any transmission policies established under this strategy must gain approval from FERC.

<u>Resource procurement</u>

- **The Commission's oversight of utility resource procurement is limited to procurement for the core class.**

  The Commission no longer directly oversees resource procurement for the non-core class. This function is served by the competitive market for electric services, with the Commission ensuring that competition is maintained. However, the utility is required to report to the Commission as part of the triennial proceeding on the extent to which procurement on the non-core side comports with the state's environmental and resource diversity goals, and in particular, how that procurement process fulfills P.U. Codes 701.1 (c) and 701.3.

o **Utility resource procurement for the core class is governed by the policies offered in Strategy A.**

The Regulatory Compact

o **The Core/Non-core strategy significantly redefines the traditional regulatory compact to reflect the changes in the industry.**

The utility no longer enjoys an exclusive franchise to serve non-core customers.

Providing the non-core with nondiscriminatory utility transmission service effectively eliminates the utility's exclusive retail franchise.

The utility is relieved of its obligation to serve those electing non-core status.

As the market for electric services becomes more competitive, regulatory policies should allow the benefits of competition to flow to both utilities and customers. In exchange for greater earnings potential, increased flexibility, and less intrusive regulation on the non-core side, the utility must accept greater accountability, as well as the risk of engaging in competitive markets. In exchange for increased choice and the ability to benefit from a more competitive electric services market, customers electing non-core status must also accept additional obligations and risks under the modified compact. To the extent non-core customers choose to receive service from an alternative provider but wish to secure backup and/or emergency services from the utility, the utility is allowed to charge an appropriate fee for such services under this strategy.

o **The means used to uphold the compact governing the core class are modified (see Strategy A).**

Assessment of Strategy C

Administrative Costs and Burdens - Administrative costs and burdens are likely to increase initially as the Commission takes the necessary steps to implement the core/non-core strategy. For example, the Commission must separate the utility's current revenue requirements between the core and non-core classes. After the initial proceeding implementing the strategy, administrative costs and burdens are likely to diminish relative to the current system. Core operations will be subject to the substantially streamlined cost-of service strategy outlined in Strategy A; non-core operations will be require even less administrative oversight once implementation is complete. The Commission will continue to establish non-core rates in a triennial rate and revenue proceeding. Balancing accounts, attrition, ERAM, and other rate adjustment mechanisms will be eliminated on the non-core side. In addition, coupled with the reforms brought to resource procurement under Strategy A, the changes brought to resource procurement for the non-core offer the potential to substantially reduce administrative costs for the Commission, consumers, parties who appear before the Commission, and the utility.

Consumer Protection - Subject to the reforms described in Strategy A, the Commission's ability to protect core customers remains intact (see assessment of Strategy A). Core customers are further protected in that they no longer compensate for any losses on the non-core side after the initial allocation of the utility's revenue requirement. Non-core customers will continue to enjoy Commission protection with respect to just and reasonable rates--the Commission will establish price ceilings and floors based on utility marginal costs. This strategy assumes that the market represents a better mechanism for disciplining prices when competition is adequate. As such, the Commission's regulation of the non-core sector will be substantially less intrusive than its regulation of the core sector. Customers who elect non-core status will have weighed the benefits (in the form of reduced costs for energy and capacity) with the risks of less regulatory oversight and protection.

Efficient Operations and Investment - The expected gains in efficiency with respect to utility operation and investment are described in detail in the assessment of Strategy A. In short, though the incentives the utility faces for efficient investment to serve core customers are substantially more balanced under this strategy than under the current regulatory framework, the incentives for efficient utility operation on the core side remain weak.

The utility will have markedly improved incentives to reduce costs for the non-core side. Those incentives stem from the considerable competition that the utility is likely to face in serving non-core customers. Moreover, within specified bands, the utility retains the excess or absorbs any shortfall in the non-core revenue requirement. This approach encourages cost-minimization and increased sales.

This incentive to increase sales, along with the elimination of ERAM on the non-core side, effectively eliminates the incentives the Commission has established to pursue energy efficiency and conservation. While the utility faces roughly comparable incentives to invest in new plant or purchase power under the non-core ratemaking structure (the effects are similar to those of the price cap; see assessment of Strategy B), the utility has virtually no incentive to invest in energy efficiency. This may threaten efficient investment on the non-core side.

Moreover, the extent of efficient investment will also depend on the nature and success of contracts among non-core customers, the utility, and other service providers. Currently, the Commission attempts to ensure efficient investment through intrusive oversight of utility resource planning and acquisition. In this way, the Commission strictly oversees resource investment, whether that investment is directed toward construction, purchased power, or energy efficiency. Under the core/non-core strategy, the Commission's oversight of resource development will be replaced by the market for energy services. Whether this market will result in efficient investment in resources is uncertain. Equally uncertain is the willingness of non-core customers to enter into long-term agreements, which developers may require to secure financing for projects, and which may also have an effect on the long-term efficiency of investment.

Finally, efficient investment will be threatened if the non-core customers are allowed to costlessly return to core status. First, if allowed to do so, non-core customers will choose their status based on the difference between average-based rates serving the core, and market-driven prices in the non-core sector. Second, the utility will face considerable difficulties planning for its core customers and the non-core market for its customers if non-core customers may return to core utility service on demand and at no cost.

Safety and Reliability - This strategy does not change the safety and reliability of the utility system for core customers (see assessment of Strategy A). For non-core customers the effect is less certain, but the strategy may reduce reliability. First, with respect to safety, the Commission's duties and responsibilities under this strategy remain intact for both the core and non-core customers receiving service from the utility. The utility will be expected to sustain comparable levels of safety for all the customers it serves. However, for unregulated providers serving non-core customers, safety is regulated by applicable state and federal guidelines, and the Commission's jurisdiction is limited.

The level of reliability for non-core customers, like investment in incremental resources, will also be governed through contractual arrangements. Though contract provisions currently address reliability (interruptible rates, for example) and should continue to do so in the future, non-core customers may initially face somewhat higher risks with respect to service reliability as the non-core market develops. In addition, to the extent the Commission reduces its oversight of non-core resource procurement, its ability to ensure reliability for the non-core may also decline unless alternative mechanisms are established.

Efficient Pricing - The core sector is likely to see limited, if any, efficiency gains in pricing (see assessment of Strategy A). The utility will face improved incentives to price non-core services more efficiently. On the non-core side, utilities will have increased flexibility to negotiate prices for generation services with individual customers, provided the contract price remains within the bounds of the floors and ceilings set by the Commission. Since the utility and its shareholders are fully accountable for costs allocated to the non-core, the utility faces a strong incentive to discount only as low as the non-core customer's willingness to pay for the services provided. This incentive will result in more efficient pricing for utility services rendered in the non-core sector.

Environmental Quality and Resource Diversity - This strategy does not alter the Commission's ability to maintain environmental quality and resource diversity with respect to utility procurement on the core side. However, discontinuing its oversight of resource procurement for the non-core, and relying instead on the competitive market for energy services, reduces the Commission's ability to ensure that these goals are achieved. For example, with respect to resource diversity, the financial incentive to maximize sales under the non-core strategy provides the utility with a strong disincentive to invest in energy efficiency programs. In addition, uncertainty remains as to whether prices in the emerging market for services will accurately account for the economic costs and benefits related to environmental quality and resource diversity. P.U. Codes 701.1 (c) and P.U. Code 701.3 reflect the view that prices for energy services in general do not properly account for these costs and benefits. To the extent prices in the competitive non-core market fail to do so, the state's goals in these areas may be frustrated.

The Pursuit of Social Objectives - This strategy severely hinders the Commission's ability to fund programs dedicated to the pursuit of social objectives through rates for non-core services. In the non-core sector, prices will be established by the competitive market for services. To the extent the Commission includes costs related to these programs in the non-core revenue requirement, the utility may not recover those costs, since to do so would require the utility to charge higher prices than its competitors, who do not face similar costs. The Commission does, on the other hand, retain its ability to fund these programs in the core sector, since core customers will not enjoy the same level of choice or competition as non-core customers. Placing the entire cost burden on captive customers raises important equity concerns, however.

Alternatively, funding for these programs could come in the form of a fee levied on the price of utility transmission services, since a majority of customers will continue to depend on the utility for transmission and distribution.

Finally, as in Strategy B (price caps), the considerable pricing flexibility the utility enjoys under this strategy may raise equity concerns among customers who discover they are paying a different price than other customers receiving like services.

Strategy D: Restructured Utility Industry

Chapters VI and VII describe the pressures that California electricity customers, especially large consumers, are placing on utilities and regulators. These customers seek open and competitive electricity markets so that they might have more freedom to control electricity services and costs. Competitive electricity markets require structures that allow the participation of many buyers and many sellers; there must be few barriers to entry for both *consumers and generators of electricity services. This option promotes a competitive market for electric services by eliminating structures that may constrain entry and limit competitive electricity generation.*

Industry Structure

- **Existing generation resources are divested to independent generation companies. The utility becomes a transmission and distribution company.**

  One premise of this strategy is that wholesale electricity generation is, or soon will be, a competitive market, characterized by many buyers and many sellers. As such, it does not require the level of regulatory oversight that is necessary for monopoly services.

- **The utility cannot own or construct new generation (or is limited to a small percentage ownership, e.g., less than 15%).**

  The Commission's experience in natural gas demonstrates the need for limits on utility involvement in emerging competitive markets to ensure that utilities do not exercise market power and impede the development of the competitive market for electric generation.

- **Customers are divided into core and non-core categories. The utility is required to offer a full range of electric services to core customers only.**

  As in Strategy C, core customers, who initially lack alternatives to utility service, should continue to receive bundled electric services from the utility. The utility will procure generation from the competitive market for generation. The utility's services to these core customers will continue to be regulated by the Commission.

- **The CPUC defines the non-core class. Non-core eligibility might initially depend on a customer's energy and capacity requirements. Eligibility should be limited in the initial period, since the Commission and the utility may require**

time to learn from and adapt to the new structure. All customers are initially classified as core customers; customers who meet the non-core eligibility requirements may elect non-core status.

Like Strategy C, the emerging competitive market for electricity resembles in important ways the natural gas industry of six years ago. Large industrial customers face or wish to have access to alternatives to utility service in order to reduce energy bills. Other customers--mostly residential customers--currently have no alternative to utility electric service.

o **The utility no longer faces an obligation to provide energy and capacity to non-core customers. Non-core customers contract with the new independent generation company or other providers for generation services.**

The utility is no longer allowed to provide generation to non-core customers. There may still be a role for the utility or independent generation company to provide back-up or stand-by generation services to the non-core on a "best efforts" basis, at least during the transition period.

The utility must provide open, non-discriminatory transmission access to non-core customers, consistent with FERC and CPUC policies.

As customers contract for their own electricity needs, the level of competition and customer choice in the electric industry is likely to increase. Access to transmission is necessary to allow the competitive market for electricity to flourish. As long as utilities control transmission and distribution, they must wheel power to ensure the success of this strategy. ***The initial non-core eligibility requirements limit the number of customers eligible to request retail wheeling.***

Ratemaking

o **The Commission will regulate rates for core customers (generation, transmission and distribution). Ratemaking for core customers will be**

performance-based, similar to Strategy B (e.g., a price cap based on initial revenue allocation, escalated by some standard index).

- **For non-core customers, the Commission will only regulate rates for transmission and distribution services. Rates for these services will be performance-based and set every three years in a consolidated rate proceeding.**

  A performance-based approach for these services offers utilities the flexibility to price at efficient levels and avoid customer bypass of the transmission and distribution system.

<u>Resource procurement</u>

- **The Commission's oversight of utility resource procurement is limited to procurement for the core class.**

  The Commission no longer directly oversees resource procurement for the non-core class. This function is served by the competitive market for electric services, with the Commission ensuring that competition is maintained. However, the utility is required to report to the Commission as part of the triennial proceeding on the extent to which procurement on the non-core side comports with the state's environmental and resource diversity goals, in particular, how that procurement process fulfills P.U. Codes 701.1 (c) and 701.3.

- **Utility resource procurement for the core class is governed by the policies offered in Strategy B.**

<u>The Regulatory Compact</u>

- **Strategy D significantly redefines the traditional regulatory compact to reflect changes in the industry.**

  The utility no longer has an exclusive franchise nor does it provide generation

service to core or non-core customers.

Providing the non-core with nondiscriminatory utility transmission service effectively eliminates the utility's exclusive retail franchise.

The utility is relieved of its obligation to serve those electing non-core status.

In exchange for increased choice and the ability to benefit from a more competitive electric services market, customers electing non-core status must also accept additional obligations and risks under the modified compact. Non-core customers may contract with the utility for back-up or emergency service at terms and conditions agreed to by the contracting parties.

- **The means used to uphold the compact governing the core class is modified (see Strategy B).**

- **The utility procures generation services for core customers from independent generation companies, power exchange markets, or independent DSM providers.**

  Resource procurement is similar to Strategy B, in which the CPUC establishes guidelines for utility resource procurement.

- **Non-core customers must procure their own electricity services by contract with independent generation companies, DSM providers, or power exchange markets. Non-core customers must also purchase transmission and distribution services from the utility.**

  Because utilities do not serve non-core customers, there is no Commission oversight of resource procurement for service to non-core customers.

Assessment of Strategy D

Administrative Costs and Burdens - Strategy D could eventually result in significantly reduced administrative burdens for utilities and regulators. Initially, this approach requires considerate administrative effort by the utilities and the Commission. In addition to the challenge of establishing initial price caps discussed for Strategy B, this approach requires that utilities divest their existing generation system. This requires the development of protocols and agreements for continuing to operate electric utility systems in a safe and reliable manner.

Rates and services for core customers would continue to be regulated by the Commission. Non-core rates and services for transmission and distribution elements would also continue to be regulated. However, the utilities, and the Commission, would be out of the business of regulating the rates of generation services for non-core customers. Over time, as the non-core expands, more and more customers would have the freedom of choices embodied in competitive markets and would require much less oversight by the Commission. This would ultimately reduce administrative burdens significantly.

Consumer Protection - Strategy D continues to provide consumer protection for those services that most require them, monopoly services although the challenge of protecting core consumers are the same as Strategy B. Natural monopolies, with their ability to constrain output, require strong regulatory oversight. For non-core customers, the Commission would continue to regulate only transmission and distribution rates and services, in the form of price caps. The non-core generation market, considered a competitive market, no longer will require state regulatory oversight. Non-core customers will have made the decision that the benefits offered by the competitive market outweigh any protections offered by regulation to core customers.

Efficient Operations and Investment - Strategy D may offer the best combination of incentives for cost minimization and efficient utility operation. Non-core customers have their own inherent incentives to find the lowest cost generation alternatives. Non-core transmission and distribution services, under a price cap approach, should be procured in an efficient manner, for reasons discussed in Strategy B. Similarly, price caps and acquisition ceiling prices can provide direct incentives to utilities to procure and operate on a least-cost basis.

Safety and Reliability - In addition to safety concerns raised by the cost-minimization pressures of a price cap (discussed in the Assessment for Strategy B), the lack of a vertically integrated utility raises some serious and fundamental questions regarding the reliability of this strategy. Non-core customers may have no back-up source should significant supply constraints appear. Core customers are no longer served by a utility that owns and controls the electric generation system; the distribution utility purchases power from generation vendors, either under contract or in the spot market. This may hinder a utility's ability to maintain reliability levels at a reasonable cost (although the existence of a market should ensure that energy will be available at some price).

Efficient Pricing - This strategy promotes efficient utility pricing for core customers in the same manner as Strategy B. While these are customers with few alternatives to utility service at the present time, the natural progression of competitive forces should eventually give core customers options to utility service. Utilities will then require the flexibility and incentives to price services efficiently that are provided in this strategy.

Similarly, this strategy provides utilities incentives for pricing transmission and distribution services at efficient levels for non-core customers in order to allow utilities the flexibility necessary to avoid uneconomic bypass of their systems by customers with alternatives.

Environmental Quality and Resource Diversity - This option significantly reduces the Commission's ability to pursue energy efficiency and renewable energy for non-core customers. These customers may find that renewable resources do not match their operational needs. Energy efficiency may be a viable option for many non-core customers but customer payback requirements for such investments may continue to be an impediment. Regardless, the Commission will no longer be able to use utilities as agents for pursuing these environmental and fuel diversity objectives.

The Commission will continue to set environmental and diversity goals for resource procurement for core customers. The energy efficiency incentive of Strategy B (in which utilities share any benefits they obtain from energy efficiency with ratepayers) continues in this option.

The Pursuit of Social Objectives - Strategy D reduces the ability of the Commission to pursue social goals through utilities. Non-core customers only purchase transmission and distribution services from the utility in this option. To the extent they are monopoly services, some rents may be captured by the utilities and regulators through transmission and distribution services. However, even these services may be avoided in the form of self-generation or energy efficiency. Core customers, without choices, can still contribute to social objectives through utility rates but even small customers may eventually have alternatives to utility service, further limiting the Commission's ability to pursue these objectives through core ratemaking.

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