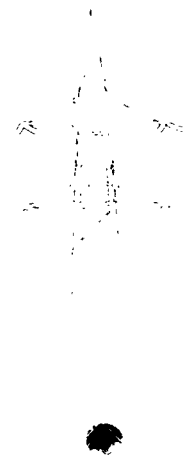
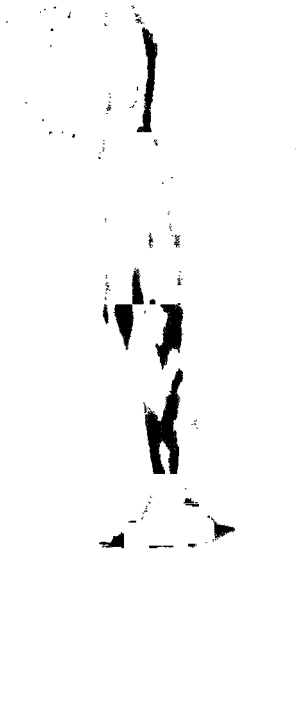
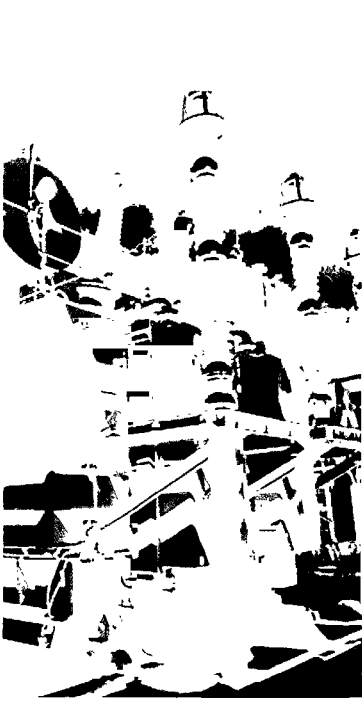


CALIFORNIA POWER CRISIS

Lessons for Developing Countries

23871

April 2001



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**JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)**

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run as part of the World Bank's Energy, Mining and Telecommunications Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and bilateral official donors in 1983, it focuses on the role of energy in the development process with the objective of contributing to poverty alleviation, improving living conditions and preserving the environment in developing countries and transition economies. ESMAP centers its interventions on three priority areas: sector reform and restructuring; access to modern energy for the poorest; and promotion of sustainable energy practices.

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CALIFORNIA POWER CRISIS

Lessons for Developing Countries

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Foreword

The U.S. electric power industry, the last major energy industry in that country subject to traditional utility regulation, is being opened up to widespread competition. Some states allow their retail electricity customers to choose their electricity supplier. Competitive trading of wholesale electricity and the emergence of independent grid operators have spread to many regions of the United States. The number of independent power producers and marketers competing in the U.S. retail and wholesale power markets has increased substantially over the past few years.

However, these new markets have not emerged without problems. California introduced competition to its retail and wholesale power markets in 1998, but has experienced a major crisis during 2000 and into 2001. This crisis has provoked a major debate about the risks, as well as the rewards, of deregulating power markets to allow competition. In fact, the California power crisis is giving deregulation a bad name, both in the United States and beyond to other countries that are reforming their power sectors.

This characterization is somewhat misplaced, however, since the California reform is more precisely characterized as part deregulation and part re-regulation. Nevertheless, some observers argue that the California experiment with deregulation should be scrapped, while others argue that the deregulation is still a worthwhile endeavor to make the electric power industry more efficient and customer-oriented, and that problems such as California's can be solved by adjusting market rules. A third group argues that California's power crisis is a failure of market design rather than a failure of deregulation.

Deregulation of power markets would be rejected on false grounds if the causes of the California crisis were largely specific to the design of the California reform. In view of this uncertainty, the World Bank has a duty to its clients and itself to gain an understanding of what has happened in California, and to draw lessons from the California experience that are applicable to other countries. The purpose of this paper is to fulfill this duty. In so doing, the paper also assesses whether the crisis could have been avoided through better market design and management. Overall, the paper concludes that much of the crisis was avoidable. Nevertheless, the paper also identifies many invaluable lessons for other countries that are considering or implementing power sector reform, and I herewith commend it to all who are involved in this endeavor.

JAMAL SAGHIR

Director, Energy and Water
Chairman of Energy and Mining Sector Board

Acronyms

CPUC	California Public Utilities Commission
CTC	competitive transition charge
FERC	Federal Energy Regulatory Commission
IOU	investor-owned utility
IPP	independent power producer
LADWP	Los Angeles Department of Water and Power
NOx	nitrogen oxides
PG&E	Pacific Gas & Electric
PPA	power-purchase agreement
PURPA	Public Utilities Regulatory and Policy Act
QF	qualifying facility
RECLAIM	Regional Clean Air Incentives Market
RMR	Reliability Must Run
RTC	retail emissions credit
SCAQMD	South Coast Air Quality Management District of Cali- fornia
SC	scheduling coordinator
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMUD	Sacramento Municipal Utility Department
TOU	time-of-use
UDC	utility distribution company

Units of Measurement

GWh	gigawatt-hour
MW	megawatt
MWh	megawatt-hour
TCF	thousand cubic feet

Introduction

“California’s new electricity market ended up being designed in a highly politicized process.... [W]hat emerged was the most complicated electricity market ever created..”
—Professor Paul Joskow , *The New York Times*, January 13, 2001

“This is a dreadful mess for a state that is held up around the world as a model of innovation....”
—*The Economist*, January 20, 2001, p.57

“Its problems are largely manmade.”
—*Newsweek Magazine*, April 3, 2001, p. 23

The California power crisis is so sudden and serious that it is prompting policymakers in many countries as well as other U.S. states to look for lessons that can be applied to the reform of their own power sectors. Concerned policymakers around the world are asking: If things can go so badly wrong with a reform that did not involve wholesale privatization of the electricity supply industry in such a rich and sophisticated economy, what are the implications for much less well-endowed countries embarking on the full menu of reform including privatization?

When a power sector reform like California’s fails, political authorities are inevitably under strong pressure to “do something” to solve the crisis. In a recent special session of the California legislature called by the governor, legislators introduced more than 75 bills intended to solve one or more aspects of the crisis. Unfortunately, quick-fix “solutions” often lead to outcomes that can be inconsistent with the original reform objectives and can produce outcomes that are even worse than the conditions that triggered the reform. For example, at the time of this writing (March 2001), the California and federal

governments have proposed or undertaken actions including the following:

- *Price caps.* The Federal Energy Regulatory Commission (FERC) imposed price caps that may deter the investment needed to overcome the current supply shortage.
- *Forced sales.* The U.S. Secretary of Energy issued several orders that required generators and natural gas suppliers to continue selling to non-creditworthy California buyers.
- *Government energy trader.* A new state law authorizes the state government to spend up to \$10 billion on the state’s credit to purchase wholesale electricity that can be resold to the three large privately owned utilities.
- *“Nationalization” of the grid.* The State of California may become the new owner of the portion of the high-voltage transmission grid currently owned by the three large privately owned utilities.
- *“Balkanization” of wholesale electricity trade.* The state’s Assembly has passed a bill that would make it difficult to export electricity produced from new generating plants located in California to buyers outside the state.

Many elements of the California reform package are peculiar to a complicated and unusual market design that was the outcome of a political compromise reached by various stakeholder groups. Many of these features will have no immediate, or even near-term, relevance for most developing countries. Since this paper has been written mainly for power sector officials in developing countries, it focuses selectively on the substantive lessons of the California crisis that pertain to the design of power sector reform in these countries.

In developing countries, the California power crisis may be creating the impression that power reform is too risky. **The power crisis in California does not justify this conclusion.** For many developing countries, the *status quo* in the power sector is the riskiest alternative of all. The *status quo* often creates a drag on economic growth through inadequate and poor-quality power supply. In addition, limited government funds are frequently diverted to the power sector that would otherwise be available for schools, clinics and roads. Therefore, most countries simply have no alternative to a substantial and basic reform of the sector that almost always requires restructuring and privatization. But like all human endeavors, power sector reform can be done well or done poorly. The principal lesson of California is that good intentions are not enough. Any reform must pay close attention to starting points, the particular problems that need to be solved, and the appropriateness of the path selected for solving these problems.

The paper is organized into three parts. It begins with an overview of the key features of the 1998 California power sector reform: how it differs from reforms elsewhere, the events and actions that have put it in a crisis mode, and the main lessons that can be learned from the crisis.

Following the overview, the main text is divided into two parts. Part I discusses in depth the lessons learned, which concern mainly the establishment and regulation of a mandatory, wholesale power market based on spot pricing. Since this is not a near-term option for many developing countries, the paper also describes other, more-limited forms of competition that may suit their situations. Although privatization was *not* an element of California's reform, the state's experience does indirectly provide important lessons for the privatization and regulation

of distribution enterprises and new market entities in developing countries.

Part II details the specific reforms initiated in California, reviews the factors that led to the crisis, and examines whether the crisis could have been avoided through better market design and management. The paper draws on numerous sources such as published articles, reports and websites, as well as the working experience of World Bank staff in numerous countries.

Overview of the California Reform and its Lessons

Why the Reform?

- *California's economy in the early 1990s.* Major statewide recession. High unemployment. Loss of industry and jobs to other states. The state's governor believed that continued high electricity prices (about 50 percent higher than the U.S. national average in 1996) would drive many industries out of the state.
- *Pre-reform electricity sector*
 - Three-fourths of the state's consumption was supplied by three large vertically, privately owned utilities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). The rest of the state was served by large and small municipal utilities.
 - High electricity prices were caused by expensive nuclear power and green power. Specifically, massive cost overruns on two major nuclear power plants and statemandated purchases of power from independent power producers (IPPs) using renewable and other technologies at prices significantly higher than the costs of traditional technologies.
 - There was surplus generating capacity just prior to the reform (April 1998).
 - Approximately 20 percent of California's electricity supply was imported from neighboring states.
 - The three privately owned utilities were regulated by the California

Public Utilities Commission (CPUC) under a traditional U.S.-style cost-of-service regulatory system with some targeted incentive mechanisms. The CPUC described the existing regulatory system as “fragmented, outdated, arcane and unjustifiably complex.”

- *Expectation.* The new market system would lower prices by encouraging competition among existing and new wholesale and retail suppliers and by reducing regulation.

The Nature of the Reform

Key Features

- The three privately owned utilities were “encouraged” to sell off their generating plants but without any vesting contracts to buy back the output of plants.
- In return, the utilities were allowed to recover their “stranded costs” (i.e., anticipated above-market costs) associated with the two high-cost nuclear power plants and the state-mandated purchases of power from certain IPPs through a “competitive transition charge” on consumers' electricity bills.
- The state government mandated a 10-percent reduction in retail rates. Retail rates were frozen for four years or until stranded costs were recovered. Actual consumer bills went down little because the reduction in rates was largely offset by the competitive transition charge.
- Retail (residential, commercial and industrial) customers were given the right to choose alternative electricity suppliers.
- A non-profit, independent system operator (Cal ISO) was created to

operate the transmission facilities owned by the private utilities (about 75 percent of the state's high-voltage grid). The Cal ISO also operated a bid-based real-time energy market as well as several other markets to acquire grid support services (i.e., ancillary services).

- A separate Power Exchange (Cal PX) was created to operate a bid-based, centralized market for forward (day-ahead and day-of) power sales. The two largest private utilities were required to buy and sell all of their electricity through the Cal PX.
- Both the Cal ISO and Cal PX were governed by large boards, each of which was made up of more than 30 stakeholder and non-stakeholder members.
- The retail electricity rates of individual privately owned utilities continued to be regulated by the CPUC. Even though the Cal PX and Cal ISO were under the regulatory jurisdiction of FERC (the national electricity regulator), the CPUC and the state government had substantial de facto influence over their actions. The two regulatory entities, the CPUC and FERC, sometimes issued conflicting orders.
- The coverage of the reform was incomplete. Municipal utilities were given the option of not participating in these new arrangements. In general, they chose not to participate.

How the California Reform Differs from Other Power Sector Reforms

- Initially, the major private distribution companies were not allowed to buy outside of the spot markets. (No vesting or forward contracting was allowed.) Hence, they were totally exposed to the

price volatility of the Cal PX spot markets.

- Distribution companies and others who serve retail customers were not required to own or have under contract sufficient generation capacity to meet their peak demands.
- No provision was made for passthrough of wholesale purchase power costs to retail rates until full recovery of stranded costs or March 2002 (whichever came first).
- The complicated design involved multiple, sequential wholesale markets operated by two new separate entities (the Cal PX and the Cal ISO). In other U.S. regions, the ISO and PX are combined in a single entity.

The Reform Process

- The reform operated by “political consensus.” The final version of the reform package reflected a compromise among competing stakeholders. It was incorporated in a bill that was passed unanimously by the California legislature.
- Criticisms of the final design by outside power sector reform experts were generally ignored by state and national political and regulatory authorities.

The Crisis

- The highly contentious siting and permitting process for new generating plants blocked the installation of any major new generating plants for more than 10 years. California's installed generating capacity increased by just 521 MW between 1996 and 2000.

- Wholesale markets operated by the Cal PX and Cal ISO worked reasonably well for the first two years (1996–98) while the initial surplus of generating capacity disappeared. Less than 2 percent of residential customers exercised their option to pick new electricity suppliers because new suppliers could not offer substantial reductions in consumers' electricity bills under the rate freeze and competitive transition charge during the reform transition period.
- A shift in market fundamentals occurred: large increases in electricity demand in California and neighboring states, reduced availability of hydropower in California and the Pacific Northwest, and big increases in the prices of gas and pollution permits to emit nitrogen oxides (NOx).
- Wholesale spot prices skyrocketed starting in the spring of 2000. California utilities paid around \$11 billion more for electricity in the summer of 2000 than in the summer of 1999. Similar wholesale price increases in neighboring states had less impact because, unlike California, only 5 to 10 percent of their overall supplies are purchased on the spot market.
- Mandated rolling blackouts throughout the state since December 2000 seriously disrupted the state economy (the sixth largest in the world). Even more widespread blackouts are expected in the upcoming summer.
- Some evidence indicates that the growing shortage of generating capacity, combined with certain features of the complex wholesale market design, may have allowed some generators to exercise market power.
- Limited or no pass-through of wholesale costs to retail customers has forced the

two largest private companies to incur around \$12 billion in unfunded liabilities since April 2000. They are on the verge of bankruptcy.

- The Cal PX ceased to operate its two markets on January 31, 2001.

The Lessons

Overall Design of the Power Market

- A poorly designed power market will not operate properly, and inadequate attempts or delays in correcting market distortions will spill over into a serious financial crisis.
- The California power reform crisis offers many valuable lessons on “what not to do” for reformers of power sectors, particularly for the establishment and regulation of a mandatory, wholesale power market based on spot pricing.
- The California experience indirectly provides important lessons for the privatization and regulation of distribution enterprises and new market entities in developing countries, even though privatization was not an element of California's reform.
- The California experience also provides a lesson about crisis management: there is no way out that is quick, painless or cheap. “Quick-fix” solutions to basic design flaws usually fail and may aggravate the problems. Any real solutions will impose heavy costs on stakeholders such as suppliers, consumers, shareholders, and legislators.

Requirements for Competition to Work in the Wholesale Power Market

- Spot markets for wholesale power require careful design of market rules and price regulation to allow participants to manage their trading risks efficiently.
- Competition requires adequate capacity to meet demand without experiencing supply constraints (generation, transmission, fuel, etc.). The market must provide signals and incentives for investment in new generating capacity when needed. These can be provided by various means, such as imposing a capacity obligation on distribution companies purchasing power in the market, setting up a parallel capacity market to the energy spot market, or developing a forward energy trading market whose prices signal expectations about future supply/demand balances.
- Competition requires that investors in new supply capacity face no major barriers to entry to the wholesale power market. These barriers include uncertainty and expense in facing delays to the permitting process, regulatory uncertainty about after-the-fact price reviews, and regulatory constraints on managing trading risks efficiently by means such as hedging instruments.
- The design of a competitive power market is too complex and delicate to be dominated by heavy political compromises that are intended to shield stakeholders from the consequences of the reform. Market design should be firmly guided by sound economic principles.
- New competitive trading arrangements in a wholesale power market should be introduced carefully to provide scope for dealing with design flaws as well as settling-in problems.

Introducing Competition to the Wholesale Power Market

- Most developing countries should start with limited forms of competition that can evolve to full wholesale competition through spot markets once the sector can manage full competition without uncontrollable market power. The creation of bid-based spot markets should generally not be their top priority.
- A mandated, deregulated, wholesale bid-based spot market should be pursued only if certain conditions are likely to be satisfied. Some of these prerequisites are also required for other, more limited forms of competition. But the consequences of not satisfying these conditions are most dramatic and harmful in a mandated and deregulated spot market.
- Price-based spot markets are generally too risky for small-to-medium-sized power systems because of these systems will lack sufficient bidders to maintain effective competition.
- Cost-based spot markets, such as those developed in Latin America, offer a simpler and less risky alternative that can yield competitive benefits for medium-sized power systems, complemented by imposing a capacity obligation on distribution companies.
- Likewise, it is simpler and less risky to impose obligations on generators and distributors to provide ancillary services (i.e., grid support services) as a condition for being connected to the grid, rather than trying to synchronize one or more separate markets for ancillary services with an untested spot energy market.
- Vesting contracts should be allowed as a form of insurance for distributors

purchasing from a new spot market. A vesting contract that fixes the sale price for trade between existing or new generators and distributors for five or more years should be established before the market goes into operation. They also provide at least initial protection against market power.

- The spot market can evolve from a cost-based to a price-based system as the power market becomes more competitive.
- Alternative trading arrangements to spot markets, such as bilateral trading among multiple buyers and multiple sellers, should be considered for small power systems and as transitional arrangements until the benefits of a spot market are considered to outweigh the risks.
- Bilateral trading becomes unsustainable as the only trading method when the complexity of balancing system supply with demand in real time becomes unmanageable as the number of buyers and sellers increase. Commercial transactions cannot be divorced from physical realities of power system operation.
- A temporary single-buyer arrangement can be considered—but with strong reservations—in situations where bilateral trading or spot markets need substantial time for development of power purchasers and sellers.

Introducing Competition to the Retail Power Market

- Retail tariffs should be aligned with the costs of wholesale power. Regulators should avoid rate freezes that expose distributors to the possibility of an unsustainable squeeze on their cash flow occurring when rising wholesale power

costs approach or even exceed fixed retail rates.

- Regulators should encourage and even require suppliers to allow large users to adjust their demand for power in real time, through smart metering and other means, since competition works properly only when both suppliers and users interact in the market (i.e., prices must be seen by both the demand and supply sides of the market).
- Interruptible supply tariffs work only when consumers do not expect to be called more than occasionally to reduce their demand on the power system. Power outages are enormously costly for consumers who have already adjusted to using grid power. Hence blackouts are symptomatic of enormous macroeconomic losses. This shows in turn the potential gains from reforming systems in such a way that such a situation is avoided.
- Small retail power users should have the option of avoiding exposure to the high price volatility that can occur in spot markets for power. Power suppliers or other entities should be given regulatory scope to absorb this volatility through risk management techniques.
- One or more commercially viable entities must have a legal obligation to provide adequate supplies for consumers who prefer to deal with a default supplier rather than shop around in the market for a supplier.
- In countries where the power supply industry is under state ownership and is due to be privatized and opened up to competition, stranded costs for past investments by utilities need not be recovered through surcharges on consumers' bills. This is because these costs will generally be absorbed by the

state through the proceeds received from the sale of these assets.

- Full retail competition should be saved for last. In countries that have not achieved substantial household electrification, it will generally be more productive to focus on encouraging competition to serve those who do not currently have access to electricity, than on retail competition for those who already have access.

Regulating Power Markets

- The economic regulatory system must be open, independent, credible and not prone to bankrupting reasonably efficient firms.
- Regulatory “certainty” for power purchases by distributors is of no value if, as in California, it can lead to bankruptcy of efficient firms. The regulatory system must be designed to allow the cost of power purchases that are beyond the control of a distributor (e.g., mandated purchases in the spot market, assigned purchases under a vesting contract or purchases under a previously reviewed bulk supply tariff) to be automatically passed through in retail tariffs.
- If there is a spot market, the regulator should encourage hedging by allowing distribution entities to recover hedging costs if hedging opportunities are available (rather than forbid it until it is too late, as in California).
- The governance of the system operator should be kept independent of the market participants. Independence can be achieved directly by prohibiting market participants from having an ownership interest in the system operator and requiring that the system operator’s

governing board be composed of non-market participants (i.e., non-stakeholders). Governance boards composed of stakeholders should not be too large or dominated by one or more classes of market participants.

- Price caps should be used only as a last resort, since they introduce distortions with unintended consequences and do not correct the causes of the problem that they address.
- The system operator should monitor markets carefully and continuously for signs of trouble—such as unusual price movements that may indicate abuse of market power—and give the system operator the authority to penalize those who violate market rules.
- An independent and expert market surveillance group should be created outside of the system operator. It should issue periodic public reports assessing the state of the market and mobilize quickly when a problem arises. The members of the group must be perceived as independent and objective.
- Regulation of fuel and power markets should be coordinated, especially the linkage between electricity and natural gas markets when most new generating plant burns natural gas.
- In large countries it is important to divide regulatory responsibilities rationally between national and state regulators to avoid unnecessary conflicts. It is not enough to simply say, as in India, that electricity is a “concurrent subject” with regulation shared by national and state regulatory authorities. The nature of the “sharing” has to be defined precisely to avoid costly and distracting conflicts.
- The economic regulator for the power sector and the environmental regulator

need to work together. Each is in a position to undermine the work of the other. The ultimate success of both regulators requires a change in their mindsets. The power regulator has to accept that compliance with strict environmental standards is an integral element of power sector reform. The environment regulator must recognize the need to work constructively with developers of new generating plants to help achieve compliance with agreed-upon environmental standards.

Part I

Lessons from California

or

What the Power Minister Needs to Know

1. Start with limited forms of competition that can evolve to full wholesale competition.

Competition is intended to produce operational and investment efficiencies. Alternative forms of competition exist that are less complex than the mandated, centralized competition model adopted in California. These alternatives can be implemented separately or in combination. None of these alternatives precludes moving to a deregulated, bid-based spot market in the future.

1.1 Cost-Based Spot Markets with Obligations for Capacity and Ancillary Services

If participation in a competitive wholesale market is mandated, then a less risky alternative is to begin with cost-based bidding (as in four Latin American countries and in New England until recently, and as proposed for Ghana) rather than price-based bidding (as in California, Colombia, El Salvador and the United Kingdom).

A cost-based spot market based on generators' actual or estimated variable production costs is easier to establish and provides more protection against market power than a bid-based spot market. It represents a relatively natural extension from the traditional merit-order dispatch systems used in many pre-reform, vertically integrated power systems. While the cost-based bid market determines day-to-day

dispatch patterns, there is usually a parallel "free" market in which generators, distributors and others can enter into hedging contracts to lock in future prices and revenues. After several years of operational experience, the cost-based spot market can evolve into a bid-based spot market. The three principal advantages of a cost-based market or pool are that it

1. Ensures efficient dispatch (if generators tell the truth about their production costs),
2. Makes it difficult for generators to exercise market power, and
3. Is easier to implement because it builds on what the system or grid operator was doing prior to the reform.

North Americans and Europeans often consider the Latin American cost-based approach to spot markets an inferior form of competition. But the reality is that it has worked even if it does not fit a textbook definition of perfect competition. Those countries that have adopted this approach in Latin America have generally experienced significant increases in private investment combined with clear improvements in operating efficiency.

The designers of the reform should consider imposing two types of obligations:

- *A capacity obligation on distribution enterprises and other load-serving entities to avoid complete reliance on a new short-term market to induce investments in new generation capacity.* This requirement—currently in effect in Eastern United States, Texas and several Latin American countries—means that anyone who sells electricity to retail customers must also have enough generation capacity (either owned or under

contract) to meet customer demands. An alternative, used in Chile and Argentina, is to require that the pool or system operator acquire capacity from generators on behalf of those who buy from the pool using administratively determined capacity payments that are in addition to the pool price. These two approaches would work in either a cost-based or a bid-based spot market. Only California appears to have introduced a mandatory spot market without any accompanying capacity obligation or capacity payment mechanism.

- *Initial obligations on generators and distributors to provide ancillary services (i.e., grid support services) as a condition for being connected to the grid.* As practiced in Latin America, England and Wales, this is generally easier than trying to synchronize one or more separate markets for ancillary services with an untested spot energy market. Once the basic energy market is functioning well, it may be less costly to acquire ancillary services through market mechanisms.

1.2 Multiple Buyers, Multiple Sellers in Bilateral Markets

Pools that operate a mandatory spot market, whether bid- or cost-based, are one form of a multi-buyer, multi-seller market. There is, however, an alternative form of a multi-buyer, multi-seller market that does not require creating a pool. This alternative allows distributors, large industrials or both to buy directly from generators and other suppliers through one-on-one bilaterally negotiated transactions. The bilateral transactions could be for short-, intermediate- or long-term supplies. It has

been suggested that this type of market would be easier to implement in developing countries because it would be voluntary and does not require the complicated protocols or software of a mandatory spot market.

Such voluntary markets involving one-on-one bilateral transactions have existed for many years in the United States and continental Europe. One big difference, however, is that the buyers and sellers were usually vertically integrated utilities with sufficient generating capacity to meet all of their energy needs. In general, these traditional vertically integrated utilities participated in these markets to “fine-tune” their supply needs (i.e., to lower their supply costs in certain hours rather than to meet their basic supply needs).

The question then is whether this type of market is feasible in a different type of industry structure. Specifically, is it a viable option in an unbundled power sector (separate enterprises for generation, transmission, system operation, distribution and retail supply) in which buyers would have little or no supply of their own and therefore would have to rely on the market for most or all of their supply needs? Moreover, would it work in a developing country where there is simply not enough generating capacity to meet the demands of all connected customers?

Because developing countries lack experience with this type of market, there are no clear-cut answers. One major concern, however, is the issue of “balancing.” Even if a distribution company is able to contract for all of its expected needs, its moment-to-moment demand will rarely be exactly equal to the amount for which it has contracted. Therefore, there has to be some balancing mechanism. (This balancing problem does not occur when the trading is among vertically integrated

enterprises because buyers will have their own generation supplies as well as the technical capacity to self-balance.) If the balancing mechanism is an organized market with more than a few generators and distributors, the cost and complexity of setting up this residual balancing market may be almost the same as a full, mandatory spot market.

One possible, less costly alternative to an organized balancing market would for distributors to acquire most of their needs through one or more supply contracts with generators, and then hire a generation company or the system operator to be responsible for meeting the moment-to-moment fluctuations in its demand. Under this approach, the balancing would be performed by the hired agent rather than by a balancing market.

Regardless of whether the underlying industry structure is bundled or unbundled, it appears that voluntary bilateral markets are feasible only if there is (1) little congestion on the grid (i.e., ample transmission capacity), (2) a small number of buyers and sellers and (3) an independent operator who has complete knowledge and effective operating control of the entire interconnected grid. This type of market may not be workable once the number of buyers and sellers rises above a threshold level because it becomes increasingly difficult to match a group of bilaterally negotiated power-sales agreements of varying durations. These agreements produce hard-to-predict physical demands on the grid, requiring a grid operator to balance the overall supply and demand of electricity on a moment-to-moment basis.

Allowing industrial customers to participate in such markets raises other concerns. If industrial customers have been subsidizing residential and other customers (which is the

case in many countries), the industrial customers will no longer be a source of cross-subsidies if they can buy from other suppliers. This, in turn, may lead to the need for a big immediate increase in retail tariffs for non-industrial customers, rather than a series of phased-in increases over a longer period of time that could be managed by phasing the exodus of non-industrial customers from the market.

It is not enough to simply provide distribution companies with the opportunity to participate in such a market. Distribution companies must also be given incentives to be efficient and intelligent buyers. In particular, the regulatory system must include explicit incentives that allow distribution companies to earn higher profits if they find more economical supply sources.

1.3 Single-Buyer Model

The single-buyer model requires that all generation supplies be procured by an entity specifically mandated to fulfill this function, and that this entity in turn be the only seller of bulk power to distributors and large users of power.

This is the “toe in the water” approach to introducing competition. In principle, it is the most limited form of competition because it allows competition only for one-time competitive procurements for relatively well-defined products—the supply of base, intermediate or peaking power for a specified period of time. In practice, however, it is often poorly implemented because the single-buyer entity is usually an existing state-owned power enterprise that is not a skilled buyer and that may be forced into signing high-priced and poorly designed power-purchase agreements (PPAs) through political or commercial pressure exerted by

its government owners. Furthermore, it carries a substantial risk that the political and commercial interests that benefit from this approach will block further reform by ensuring that it remains in force.

Although single buyers tend to be state-owned enterprises, state-owned entities usually have limited experience in purchasing power, and this lack of experience may put the future budget revenues of their governments at considerable risk. This could be the case in California, where an existing state agency has become the *de facto* buyer for about 50 percent of the short- and long-term supply needs of the three privately owned utilities. This happened because generators in California and neighboring states were no longer willing to sell to these three companies, which account for about 75 percent of California's retail sales, because the three companies could no longer pay for their power purchases. But simply replacing these companies with a state-controlled single buyer will clearly not be a solution if the three utilities are not allowed to charge tariffs to their retail customers that are high enough to allow them to pay for the power that they will now purchase from the state agency. Almost exactly the same situation exists in the Indian state of Orissa, which, like California, was the first state in its country to undertake significant reform. The four privately-owned distribution companies in Orissa are unable to pay for the power purchased by the state-owned single buyer because their retail tariffs have been set too low.

Because the single-buyer model in developing countries often postpones an essential element of reform (i.e., raising retail prices to cover costs), it frequently forces governments to offer backup payment guarantees they usually can't afford because ultimate consumers are "insulated" (at least

temporarily) from bulk power costs. However, what consumers do not initially pay for in electricity rates, they (and those who do not have access to electricity) will eventually pay for in higher taxes or in the reduction of other government services (e.g., hospitals, roads and schools) that are "crowded out" because of the subsidies or guarantees that now go to the electricity sector. In California it has been reported that a state government surplus of several billion dollars will soon be exhausted because of the need to cover power purchases by the state buying agent. Standard & Poor's, a U.S. credit rating agency, put the state on a credit watch "with negative implications" when the state began to purchase power.

Countries with small power systems may be tempted to consider adopting a single-buyer model because unbundling generation and distribution into a number of small entities, combined with sophisticated market mechanisms, may not be a realistic option for such systems. In the more than 100 countries with installed capacity of less than 1,000 MW, the potential number of operators and distributors in the bulk supply market may simply be too small to support workable, ongoing competition unless the country has strong interconnections to neighboring countries. Moreover, trying to introduce sophisticated trading arrangements could divert attention from other higher priorities, such increasing supply, reducing losses and providing electric power to those who are currently unserved.

Other options besides the single-buyer model exist for purchasing wholesale power in small power systems. One approach worth considering is a "joint action agency." This is a common model used by groups of small power systems in several parts of the United States, including California (e.g., the Northern California Power Agency). A joint action agency is essentially a buying

cooperative made up of small distribution systems that pool their demands and hire purchasing expertise. It is different from the pure single-buyer model in two important respects. First, the buying cooperative is an entity created and governed by the buyers rather than a separate, government entity that is not accountable to its customers (the current norm in many developing countries). Second, it is voluntary. If a small distribution system believes that it can do better job by purchasing on its own, it always has the option of “going off on its own” as long as it satisfies its previous purchase commitments.

2. Move to a full bid-based spot market only once the necessary conditions are in place.

A full bid-based spot market provides helpful price signals needed by consumers and potential investors when the necessary conditions are in place. It is *not*, however, the highest reform priority in a power sector that is starting from a base of pervasive under-pricing, significant cross-subsidies, overstaffing, high technical and commercial losses and widespread political interference. The danger of trying to create such a spot market too soon in the reform process is that the effort required to make it work properly will divert attention and resources from trying to solve more fundamental problems. It is a potentially time-consuming distraction when more basic problems need to be addressed.

A mandated, deregulated, and bid-based spot market should be pursued only if certain conditions are likely to be satisfied. Some of these prerequisites are also required for other, more-limited forms of competition. But the consequences of *not* satisfying these conditions will not be as dramatic or as harmful as they would be in a

mandated and deregulated spot market. The conditions include the following:

- Market power is not pervasive. There are sufficient non-affiliated suppliers in each segment of the system load curve, no serious bottlenecks exist in the transmission system, and control of fuel supply is not under the control of a major generator. This condition is unlikely to be fulfilled in a country with a small power system and few interconnections with power systems in neighboring countries.
- Distributors have the money to pay for their power purchases and distribution costs (i.e., retail tariffs are cost reflective and are not artificially suppressed for political reasons). Competitive power markets will fail unless distribution entities and other buyers are commercially solvent. California started with commercially viable distribution entities but then pushed them towards bankruptcy by forcing them to buy in a spot market in which prices skyrocketed and the regulatory system (which was the result of a political compromise) prevented the two largest distributors from passing these high bulk-power costs through to their retail customers.
- Buyers and sellers in a deregulated market have the means and incentive to hedge price volatility in forward spot markets, through intermediate and long-term contracts, etc., and are not forced to rely completely on mandatory, short-term bulk power markets. Apart from vesting contracts (see below), volatility in spot electricity prices can be hedged with a variety of other financial instruments such as futures contracts, options and derivatives. The market for such instruments are not easy to create, can

be manipulated if there is not enough volume and, more importantly, may divert attention from more critical “first order” tasks such as raising tariffs so that distribution entities can recover their total cost.

- There are few bottlenecks on the transmission system that would block transactions and create segmented markets. If there are bottlenecks, a workable and efficient system exists for pricing congestion. For example, transactions in a day-ahead or hourly energy market should not be arranged in isolation from whatever congestion exists on the grid.
- The market and system operator are genuinely independent in ownership and decision-making from market participants (generators, distributors, retail and wholesale suppliers and final customers). The governance system in California resembled a mini-legislature and was susceptible to deadlocks.
- New generation and transmission capacity can be built without excessive delays in permitting and siting (i.e., supply can respond to market prices). In California, the susceptibility of the siting and permitting process to legal challenges by nearby residents was a major barrier to entry for new generators. In developing countries, similar delays could be caused by weak environmental agencies that are administering cumbersome administrative processes.
- Retail tariffs are designed so that at least large- and medium-sized customers can “see” spot market prices on an hourly basis and can cut their consumption in response to high prices (i.e., demand can respond to

high prices). Consumers cannot “respond” to a price that they cannot see. California distribution companies are now pursuing a crash effort to install real-time meters and tariffs for their large customers before summer 2001.

- Sufficient time, money and human resources are available to develop the new market system. A fully developed, bid-based spot market system involving multiple sellers and buyers requires significant expenditure on real-time metering, bidding protocols, settlement and market-making software and communication and data transmission equipment. Much of these costs are independent of the size of the power market. California is a rich state, so it was able to finance a veritable army of consultants working under extremely tight deadlines to install the necessary hardware, develop the protocols and write the corresponding software. In contrast, most developing countries will not have these resources. And even if they did, these limited resources would produce bigger and more immediate benefits if used in extending service to unserved households, putting in retail meters where such meters don’t exist and making transmission and distribution investments to improve the basic quality of current service.
- There is a “workout” of high-priced power purchase agreements with IPPs or an explicit stranded-cost mechanism in place before the market becomes operational. A wholesale market will generally not work unless this happens.

Policymakers sometimes fail to appreciate that it is more difficult to create a bid-based

spot market in electricity than in other energy commodities because of the basic physical realities of electricity production and consumption:

- Electricity is very expensive to store.
- It is subject to rapid changes in demand.
- There are pervasive externalities on the grid. For example, physical failure at one location can cause the collapse of the entire grid supply.
- Its demand and supply must be balanced on a moment-to-moment basis.
- The demand for electricity (on a real-time basis) can be very unresponsive to price increases.

3. Allow vesting contracts as a form of insurance for distributors purchasing from a new spot market.

Before the market goes into operation, the government or its privatization agency should establish a vesting contract that fixes the sale price for trade between existing or new generators and distributors for five or more years. (The same technique, which is sometimes described as “allocated PPAs,” can also be used when new distribution entities are created even in the absence of an accompanying spot market.) Vesting contracts provide “insurance” in case the market design is flawed, and they provide revenue and cost certainty to generators and distributors in the early years of reform. In most countries that have created short-term markets, vesting and other hedging instruments may cover as much as 80 to 90 percent of total power trade. This was not the case in California, however. The largest distributors were required to sell generating plants and were not allowed to repurchase the output of these plants using vesting

contracts. Instead, they were required to purchase almost all of their supply needs in the newly created spot market. This is the functional equivalent of requiring that everyone buy their airplane tickets for a particular flight in a mandatory auction that takes place 30 minutes before the scheduled departure.

However, vesting contracts are not risk-free for distribution companies. If the contract prices are high because of corruption or a non-competitive or poorly negotiated procurement process, future distribution companies and their customers may not be able to pay the high prices. In such cases, a vesting contract will simply perpetuate a bad outcome and lead to “stranded costs” when and if competition is introduced. Starting power sector reform with a legacy of high-priced PPAs is like starting a race with a 20-kilogram weight on each leg.

Vesting contracts can also be used with the creation of separate distribution entities through privatization or divestiture, even if these actions are not accompanied by the creation of a spot electricity market. Such contracts reduce uncertainty for potential investors in both distribution and generation. They also allow the regulator to focus in the early post-privatization years on distribution costs and performance (e.g., wires’ costs, technical and non-technical losses, billing and collections) that are under the more direct control of distribution entities.

Vesting contracts are a transition mechanism. When the contracts expire or when the distribution companies make additional power purchases, the regulator will need to establish a system to ensure that the distribution entity purchases economically to protect its captive retail customers. And the regulatory system must provide incentives for distribution companies to enter into a portfolio of

purchase contracts to continue to hedge price risks.

4. Save full retail competition for last.

Retail competition did not succeed in California for several reasons relating to the specific design features (e.g., a 10-percent mandated rate reduction combined with a rate freeze, the recovery of stranded costs through a competitive transition charge) of the California retail competition program. But even if California had been successful in introducing retail competition, this does not imply that most developing countries should make retail competition an early action in their reform programs.

Full retail competition (i.e., allowing every retail customer the right to pick their electricity supplier over an existing distribution network) is expensive and complicated to implement. In England and Wales, it has been estimated that the initial hardware (metering, data transfer and telecommunications systems) and software has cost more than US\$1 billion so far.

It appears that other countries (Australia and Norway) and other U.S. states (Pennsylvania) have had more success with full retail competition than California. But it also important to remember that these countries, like California, are starting with full household electrification.

In countries that have not achieved substantial household electrification, it will generally be more productive to focus on encouraging competition to serve those who do not currently have access to electricity, rather than on retail competition for those who already have access. For example, in poor, rural areas, the competition may be for the right to receive a government subsidy

(whether it is for capital, operating costs or both) in return for an obligation to provide a specified level of grid or off-grid service (Argentina and Chile). In other countries, privately or cooperatively owned mini-grids with an accompanying generating unit (i.e., a mini-privatization) in rural areas can be encouraged if regulatory licensing requirements are kept to a minimum and the mini-grid providers are allowed to offer electrical service with lower quality-of-service standards than the main grid distribution companies. If the mini-grid operator wants the option of being connected to the main grid for enhanced reliability, then the key regulatory issue is the terms and conditions of the backup service that is provided to it by the main grid distribution company or a separate generation company. The general rule is that the regulator should not impose regulatory requirements above and beyond the willingness and ability of people to pay.

Policymakers should also consider adopting a simpler version of retail competition—by tying the energy prices paid by residential customers to a measure of market prices paid by industrial customers who have access to competing suppliers. This “piggybacked” form of retail competition should be easier and less costly to implement than full retail competition. A variant of this approach has been adopted in Chile.

5. Starting points matter.

The starting conditions in power sectors vary enormously among reforming countries. The “starting points” are particularly important in four areas:

1. *Prices.* Are retail power prices above or below costs? In California, the pre-reform prices were high, but in many developing countries the prices are too

low to recover costs. It is virtually impossible to undertake any serious power sector reform (including the creation of ongoing bulk power markets) unless a government is politically committed to closing the revenue-cost gap as its first priority.

2. *Capacity.* Is generation capacity adequate to meet the demand in the power market? In California, the reform started with a cushion of excess capacity, while many developing countries have a shortage of capacity. Is there potentially enough within-country generation capacity (assuming weak interconnections to other countries) to make it worth thinking about a national bulk power market? In Africa, among the 34 sub-Saharan countries that each have less than 1,000 MW of installed capacity, spot markets and other forms of ongoing bulk power competition, while interesting to read about, are largely irrelevant to their immediate problems (unreliable service, high losses and insufficient generating capacity).
3. *Coverage.* Is there full electrification? California has full electrification coverage. In many developing countries in Asia, Africa and Latin America, large segments of the population lack access to electricity. For example, of the 34 countries of sub-Saharan Africa, more than 90 percent of the countries have less than 20 percent household electrification.
4. *Institutions.* Will investors and consumers trust regulatory and government institutions to honor commitments and treat them fairly? In California, the state and national regulators have existed for more than 60 years and have established a good

track record of honoring their commitments. In many developing countries, the regulator is a new institution, its responsibilities vis-à-vis the government may not be clear, and previous governments may have a history of renegeing on agreements. In effect, there is often an “institution gap” as well as a “supply gap.”

The reform transition strategy should reflect starting conditions and country characteristics. For example, in a country starting with suppressed prices (i.e., prices that are less than costs) and a shortage of supply, there is a greater political risk to introducing deregulated bulk power competition than in another country that starts with cost-reflective prices and a surplus of supply. Similarly, it makes little sense to try to create a deregulated bulk power market in a small country with weak interconnections to neighboring countries. The better strategy is to privatize what already exists, provide subsidies for rural electrification and strengthen interconnections to neighboring countries (Central America) before contemplating a deregulated, bulk power market.

Basically, it makes little sense to start a power sector reform without first deciding which problems need to be solved. If a country moves too quickly to a complex bulk power market that is inappropriate to its current problems, it runs the risk of losing what may be a “once-in-a-generation” chance to make fundamental reforms in its power sector. Power sector reform is a highly political process. Policymakers need to be alert to the fact that the necessary political support will quickly disappear unless the reforms produce “early wins” that are readily discernible to the general public.

6. The economic regulatory system must be open, independent, credible and not prone to bankrupting reasonably efficient firms.

Independent regulatory commissions are necessary but not sufficient for sustainable power sector reform. It matters little to investors that a regulatory commission is “independent” if the commission issues tariff decisions that make it difficult or impossible for a reasonably efficient distribution company to recover its total costs (purchase power plus wires costs).

6.1 Distribution

Multi-Year Tariffs

Most developing countries that have successfully privatized distribution have given potential investors reasonable certainty about the initial revenue stream for 5 to 8 years through a multi-year tariff formula that is fixed in the law or a concession agreement (akin to a contract between the government and the investors). Because this tariff-setting system is usually an integral and legally binding element of the overall privatization package, the regulator may have very little to do with setting tariffs in the initial post-privatization period. This has been the norm in Bolivia, Chile, El Salvador, Georgia, Guatemala, Moldova and Peru.

Multi-year tariffs are the regulatory equivalent of going on “autopilot.” Although they reduce risk for investors (and have been adopted in almost every country that has successfully privatized distribution), they may be difficult to implement if there is considerable uncertainty about the initial levels of cost, consumption and losses and the level of investment needed in meters,

lines, transformers and substations to raise service to acceptable standards. A multi-year tariff that turns out to be too generous to new private companies also runs the risk of a political backlash that could lead to after-the-fact windfall profit taxes or even re-nationalization. Consequently, it may make sense in some countries to combine a multi-year tariff with a profit- and loss-sharing mechanism outside of a pre-specified dead band. Such a sharing mechanism increases the political sustainability of the reform.

Any multi-year tariff should also be combined with performance standards so consumers can experience some improvements in service to balance the pain of tariffs that are initially likely to be higher. However, the performance benchmarks must be developed with considerable care. In particular, any benchmarks must (1) take account of starting points (e.g., technical and non-technical losses on the system), (2) recognize that not all customers may want or can afford the same levels of quality, (3) be able to be objectively measured and (4) be bounded with respect to their financial impact on the enterprise.

Purchased Power

Like regulatory “independence,” regulatory “certainty” is of no value if, as in California, it can lead to bankruptcy of efficient firms. For distribution companies, it is especially important that the regulatory system must be designed to allow for the automatic pass-through to retail tariffs of purchase power costs that are beyond the control of the distributor (e.g., mandated purchases in the spot market, assigned purchases under a vesting contract or purchases under a previously reviewed bulk supply tariff). Where the distributor has some discretion in its purchases (e.g., post-privatization purchases for incremental demand growth),

the regulatory system should create incentives for the distribution company to minimize its purchase power costs. It appears that such incentives did not exist in California. The privately owned utilities were generally reluctant to pursue potentially cost-reducing, long-term purchases in 1999 for fear that the purchases would be found “imprudent” in a later, after-the-fact regulatory review.

Incentives to Hedge

If there is a spot market, the regulator should accommodate hedging by allowing distribution entities to recover hedging costs if hedging opportunities are available (rather than forbid it until it is too late, as in California). There needs to be a balance in the regulatory system. The regulator should not write a blank check by accepting all hedging costs, nor should the regulator discourage distributors from hedging because they fear disallowance of profits under after-the-fact “prudence” reviews. The better approach would be to establish before-the-fact price benchmarks for wholesale power purchases to encourage efficient buying. The indexed purchasing power benchmarks created by the electricity regulators in Northern Ireland, Scotland and the Netherlands are useful models. The choice of benchmarks is critical. Several Latin American countries have adopted an index based on six-month estimates of nodal prices as the purchased power benchmark. However, they have found that the distribution companies will simply rely on their legal right to buy all of their power needs at these prices and not attempt to engage in any hedging transactions.

Blaming the Regulator

A politician can do few things more unpopular than raising electricity tariffs. The

Governor of California was quoted as saying that he could have solved the crisis in “20 minutes” if he had been willing to raise retail tariffs. Although political authorities in developing countries are often initially nervous in allowing the creation of “independent” regulatory commissions, they frequently discover the political convenience of attributing necessary but unpopular tariff increases to the independence of their regulatory commissions. The principal benefit is the ability to say that the tariff increases are beyond one’s control. For example, when the California Public Utilities Commission announced average retail tariff increases of 40 percent, on top of an earlier 10 percent increase, the Governor was quoted as saying: “I can’t order or direct an independent body. I’ve not given any advice to them on the subject of a rate increase.” (*Washington Post*, March 27, 2001, p. A2)

6.2 Market Regulation and Monitoring

Governance of System Operators

The governance of the system operator should be kept independent of the market participants. Independence can be achieved directly by prohibiting market participants from having an ownership interest in the system operator and requiring that the system operator’s governing board be composed of non-market participants (i.e., non-stakeholders). But it may not always be possible or desirable to create a non-stakeholder board in some developing countries. Therefore, the alternative is to create a stakeholder board where no entity or class can dominate board decisions. The failure of the California stakeholder board suggests four lessons:

1. The board cannot be too large or it will be ineffective as a decision

making body. (The California system operator board had 25 voting members before the Federal electricity regulator dissolved it.)

2. The voting rules must ensure that one or two classes cannot control the board's decisions.
3. The regulator must be able to step in and make a decision if the board is deadlocked.
4. Consumer representatives or advocates should be viewed as market participants.

Price Caps

Once a market has been created, price caps should be used only as a last resort if serious structural or market design flaws emerge. When prices go up, the natural instinct of most political authorities is to impose price caps. But price caps distort markets, and they treat symptoms rather than causes. If the underlying problem is a shortage of generation capacity, a price cap will not help with the two needed solutions: increasing supply and restraining demand. As the former FERC chairman observed: "We cannot 'price cap' California out of a supply shortage."

With any price cap, there is always a danger that it will be set too low. For example, it appears that the price caps imposed in California were at times below the (historically high) variable production costs of some old generating units, and so prevented these units from operating profitably when the system needed their output. If price caps are put into place, they should be applied comprehensively across all markets in which a generator might sell. If they are imposed piecemeal, generators will simply sell in other markets where the price is not capped at all or capped at a

higher level (as happened in California), thus defeating the purpose of the caps. Price caps must be a temporary, last-resort measure. If they are kept in place for too long, they will reduce the pressure to deal with the underlying problems and will ultimately prevent the market from developing as originally planned (as happened with the wholesale electricity market in the Ukraine).

Monitoring by System Operators

Regulators should require the system operator to monitor markets carefully and continuously for signs of trouble—such as unusual price movements that indicate abuse of market power—and give the system operator the authority to penalize those who violate market rules. The system operator has detailed knowledge of daily operations and therefore is in a unique position to serve as the regulator's "eyes and ears." In California, several (but not all) of the recommendations made by the Cal ISO's monitoring unit, as well as an external monitoring unit (see below), were adopted by regulators.

Monitoring by Outsiders

An independent and expert market-surveillance group should be created. It should issue periodic public reports assessing the state of the market and mobilize quickly when a problem arises. The members of the group must be perceived as independent and objective. A small- or medium-sized country might have to hire experts from outside the country because most knowledgeable people within the country will be perceived, at least initially, as being biased because of past connections with the industry. The surveillance group must have a broad mandate. It should be charged with

assessing not only the performance of the market, but also the actions of the system operator and the regulator. (For example, in California the market surveillance group has concluded that the “soft price cap” imposed by the FERC would probably worsen the existing supply shortage.) Finally, the market surveillance group should work with the system operator but must have the clear right to issue reports without the prior approval of the system operator.

Self-Regulation

Where organized spot or balancing markets are created, industry “self-regulation” of the accompanying grid and commercial codes should be encouraged. In California, these technical advisory groups were able to make some technical improvements in grid and market operation. The regulator need not formally approve every decision or arbitrate every dispute, but the regulator must have the legal right to intervene on its own initiative or in the event of a formal complaint by a market participant.

Regulation of Fuel and Power Markets

Regulators must coordinate the regulation of fuel and power markets—especially the linkage between electricity and natural gas markets when most new generating plant burns natural gas. For example, if a generator is owned by or affiliated with a company that provides natural gas transportation to competing generators, this corporate relationship could be used to put its competitors at a competitive disadvantage.

6.3 Division of Authority between National and State Regulators

In large countries (e.g., Argentina, India, Brazil, Canada, China, Russia and the

United States), it is important to divide regulatory responsibilities rationally between the national and state regulators to avoid unnecessary conflicts. It is not enough to simply say, as in India, that electricity is a “concurrent subject” with regulation shared by national and state regulatory authorities. The nature of the “sharing” has to be defined precisely to avoid costly and distracting conflicts. The areas of regulation actions that are likely to cause friction include

- Transmission siting and certification
- Transmission tariffs
- Bulk power tariffs
- Grid codes
- Commercial and governance rules for regional trading entities and grid operators.

In California and the rest of the United States, the division of regulatory authority has not always been clear or appropriate.

Also, political authorities need to recognize that the division of regulatory authority will probably have to change as the industry structure changes. In particular, a division of regulatory authority that may have been workable under a vertically integrated industry structure may break down as the industry moves to an unbundled, vertically de-integrated structure.

6.4 A Caveat: Regulating State Enterprises Is Different from Regulating Private Companies

Although California provides many useful lessons in “how not to regulate,” there is a hidden assumption behind these lessons. It is that the enterprise that is being regulated will respond to the incentives created by the regulatory regime. This may not be true in many developing countries that have

recently created new, separate electricity regulatory bodies that are regulating government-owned enterprises. These regulatory entities often borrow regulatory techniques that were developed to exploit the profit-maximizing objectives of private companies, and try to apply these techniques to public enterprises.

However, the inescapable reality is that most public enterprises, despite lengthy and expensive programs to “commercialize and corporatize” them, still usually act like public enterprises. In particular, because they do not pay much attention to profits and commercial performance, many of the attempts to create regulatory incentives are lost on them. As a consequence, regulators who find themselves regulating public enterprises often spend considerable time writing impressive orders filled with directives that, in the words of one new Indian electricity regulator, read like “pretty poetry” but which are “rarely read and almost always ignored.”

While it is relatively easy to produce a list of regulatory lessons that can be learned from the California experience, many of the lessons will be inapplicable to a developing country unless the state-owned power enterprise can be made to act like a commercial enterprise (which seems to be rare) or until the state enterprise is privatized.

7. Economic and environmental regulators should talk to each other.

In many developing countries, environmental standards that apply to the activities of state-owned power entities sector have been either non-existent or loosely enforced. Where standards exist, state-owned enterprises, operating with tight budgets and lax maintenance standards, have

often acted as if compliance were a low priority. Similarly, the attitude of most environmental regulators has been indifference to compliance by state-owned power entities because of government reluctance to face the costs of enforcing compliance. As power sectors become increasingly privatized, however, governments and their environmental regulators are re-discovering the local and global importance of compliance with environmental standards, and are willing to put more effort into enforcing these standards.

The California experience shows that reform of the way that the power sector is regulated economically should be coordinated with environmental regulation of the sector. Environmental regulation contributed substantially to the high bulk supply prices because it acted as a significant barrier to increasing the supply of electricity in California. The problem was not so much the standards themselves (which continue to be strict), but how they were implemented. Specifically, it took almost twice as long to get state and local siting and permitting approvals for a new generating plant in California as it did in any other U.S. state. The legal and political system allowed inhabitants near the sites of the proposed facilities and environmental groups to block or substantially delay the siting and permitting process for most new generating plants. As a consequence, supply stagnated, while demand steadily increased.

The specifics of power sector environmental regulation—determining which pollutants should be controlled and at what levels, and deciding whether market or non-market control mechanisms should be used—are beyond the scope of this paper. However, it is clear that decisions about the substance and process of environmental regulation cannot be undertaken in isolation from

power sector reform decisions. Most electricity regulators would prefer to oppose unduly restrictive environmental standards that raise costs at precisely the moment when electricity prices may need to go up for other reasons. Similarly, most environmental regulators tend to take the narrow view that their mandate is only to ensure compliance with environmental standards. In particular, they do not feel any real responsibility for the overall success of power sector reform or, more immediately, whether a particular plant does or does not get built.

The reality is that these regulators need to work together. Each one is in a position to undermine the work of the other. The ultimate success of both regulators requires a change in their mindsets. The power regulator has to accept that compliance with strict environmental standards is an integral element of power sector reform. The environment regulator must recognize the need to work constructively with developers of new generating plants to help achieve compliance with agreed upon environmental standards.

Part II

From Reform to Crisis in California

1. Background

The reform of the California power market is often characterized as a process of deregulation. In fact, the reform involved limited deregulation by introducing price-based competition in an elaborately structured wholesale power market, and it changed the way that the power market is regulated. It did not involve divestiture of state-owned assets. Hence the reform is more precisely characterized as part deregulation and part re-regulation. The reform also involved some restructuring of market functions by

- Obliging the incumbent utilities to sell some of their power generating capacity to independent suppliers,
- Unbundling their distribution arms from their generation and transmission arms,
- Placing responsibility for grid operation with an independent system operator, and
- Establishing separate markets for energy and ancillary services.

Most U.S. states have started or plan to start programs to deregulate their power markets. California was one of the first to start because of its desire to lower its retail electricity prices. Competition in the power market was introduced through divestiture of generating capacity by incumbent utilities, development of new power plants by IPPs, and extension of competition gradually to retail supply. California's

progress in adopting policies that give consumers the right to choose their electricity supplier—the key and ultimate indicator of competition in the market—ranks about average for the 24 U.S. states that have already implemented reforms, according to the Retail Energy Deregulation Index (a scorecard developed by the Center for the Advancement of Energy Markets).

Part II of this paper proceeds in the following sections. First, it summarizes the indicators and consequences of the California power crisis. It then outlines the main parameters of the California power market, describes the formation of the new power market under the 1996 reform, and reviews the factors that led to the crisis. It concludes by assessing whether the crisis could have been avoided.

2. The Indicators of the California Power Crisis

The California power crisis of 2000-2001 has had two distinct phases: (1) during the summer months, when demand rose sharply because the power load from air-conditioners increased under a record-breaking heat wave; and (2) in the winter months of 2000–2001, when power supply fell sharply under seasonally low hydropower output and heavy withdrawals from service of old thermal power units for maintenance.

The serious nature of California's power crisis is shown by numerous indicators for the state's economy that has been the engine of high-technological growth in the United States. Resolution of the crisis is proving difficult and is imposing heavy costs on the stakeholders—suppliers, consumers, shareholders, legislators, etc. The consensus

is that there is no way out of the crisis that will be quick, painless or cheap.

- Wholesale electricity prices during 2000 were more than three times the 1999 level. Huge spikes in wholesale power prices occurred during the summer months of 2000. The market was declared dysfunctional by all who studied it then.
- Retail electricity prices in the San Diego area in 2000 were up to three times higher than in 1999; one household reported, for example, an increase in monthly electricity bill from \$129 to \$353 for the mid-December to mid-January period.
- The first sustained series for decades of brownouts and blackouts occurred during the months of November 2000 to February 2001, when system demand was seasonally low, forcing temporary closures of businesses and social institutions.
- Industrial and commercial users of electricity have been paying massive penalties rather than cutting their power usage under interruptible supply contracts. Electricity is so vital for Silicon Valley that even a one-day power outage, such as the one that occurred in June 2000, reportedly cost as much as \$100 million in lost output.
- The two main power utilities are facing bankruptcy, claiming that they have accumulated some \$12 billion in uncompensated costs because of the high prices that they have been paying for wholesale electricity from power generators. Each was losing around \$400,000 per hour on electricity trading during January 2001. They currently lack the credit to purchase wholesale power, and their debt rating has been slashed to junk-bond status.

The crisis has had the following immediate consequences:

- A Stage 3 alert to power consumers, which had seldom been declared up to the end of 2000, was declared for an unbroken series of 32 days during January and February 2001. A Stage 3 alert is the severest indication of an impending power system brownout or blackout, when the system capacity reserve margin falls below 1.5 percent of peak demand.
- The state government has declared several dozen statewide emergencies to urge consumers to conserve electricity, but this has not been much help.
- The financial crisis caused by the default on payments by the main utilities has threatened to spread to the banking community.
- The Federal Secretary for Energy invoked emergency powers on December 13, 2000, to order power generators to continue selling into the California power market.
- Natural gas suppliers threatened stoppage of deliveries of natural gas to the main power utilities this winter, because they are concerned about the utilities' ability to honor payment commitments.
- The state government has enacted measures that place it firmly in the center of the California power market (e.g., becoming the principal buyer of energy for the two largest utilities), thus effectively flying against the world-wide trend towards deregulation and privatization of electricity trade.
- The main organized wholesale energy market—the California Power Exchange—has ceased to function

effectively and faces extinction, because of the utilities' loss of credit on the exchange and a move to long-term contracts for bulk power in response to the crisis.

- Serious power shortages in California are expected to continue for the next two years, especially during the summer months.
- Serious impacts on California's economy are a concern, including threats by businesses to move away, and the repercussions on the rest of the country.
- Other states are reconsidering plans to deregulate their electricity markets. Nevada, for example, has postponed power deregulation plans, in part to stop generators from selling electricity to higher-margin markets in California. Regulators in Arkansas are recommending a two-year delay to their plans.

3. Main Parameters of the California Power Market

The main parameters for the California power market in 2000 are summarized herewith.

- Retail supply of electricity in California is dominated by three investor-owned utilities (IOUs)—Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E)—and two municipal vertically integrated monopolies—Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility Department (SMUD). Their service areas are discrete zones, so they have traditionally not competed with each

other for business, except for new industrial customers.

- California currently has about 53,000 MW of installed generating capacity with the following distribution of ownership:

Public agencies comprising the LADWP and SMUD	23%
Renewable energy producers and co-generators, supplying under long-term contracts based on Public Utilities Regulatory and Policy Act (PURPA) legislation	22%
Investor-owned utilities (IOUs)	15%
IPPs, most of which is held by five major power firms (AES, Reliant, Duke, Southern and Dynergy) based outside the state	40%

In addition, California's imports of power provide about 5,000 MW towards meeting system load.

- California's installed generating capacity by type of generator is as follows:

Hydropower	24%
Coal-fired steam generators	6%
Oil and/or gas-fired steam generators	37%
Nuclear	8%
Combustion turbines and combined cycle plant	8%
Geothermal, wind, solar, municipal waste, etc.	17%

- The sources of the 275,800 GWh of wholesale supply of electricity in 1999 by type of energy resource were as follows:

Hydropower	15%
Coal	13%
Oil and/or gas	31%
Nuclear	15%
Geothermal, wind, solar, municipal waste, etc.	8%
Energy imports	18%

This distribution did not change much throughout the 1990s.

- Peak load on California’s interconnected power system in 2000 was about 51,400 MW including the loads on the public agency systems. The breakdown of this load by service area was as follows:

PG&E	41%
SCE	38%
SDG&E	6%
LADWP	10%
SMUD	5%

- Retail electricity consumption by sector in 2000 was as follows:

Residential	30%
Commercial	36%
Industrial	21%
Agricultural	7%
Other categories	6%

- Retail electricity prices—expressed in terms of average tariff yield of U.S.cents/kWh—by consumer category for California during 2000 are given below. They show that California’s electricity tariffs are about one-third higher than the U.S. average.

	<i>California</i>	<i>U.S. Aver</i>
Residential	10.6	8.3
Commercial	9.9	7.3
Industrial	6.2	4.5
Other	3.7	6.1
All Sectors	9.0	6.7

4. Formation of the New Power Market under the 1996 Reform

Before the reform, the IOUs were vertically integrated and were able to recover their costs of generating and supplying electricity through the bundled rates that they charged their customers, as long as the sector

regulator—the California Public Utility Commission (CPUC)—approved these costs as being “reasonable” and prudently incurred.

The reform of the California power market was implemented according to CPUC’s restructuring order issued in December 1995, which led to the enactment of Assembly Bill 1890 (AB 1890) by the California legislature in September 1996. The objective of the reform was to reduce the costs of electricity because California’s electricity prices were much higher than the national average under traditional regulation. At the same time, however, the concern was that competition would push wholesale prices so low as to render unviable the investments in new power capacity needed to meet growth in demand, while exposing consumers to high price volatility. AB 1890 was thus designed to deal with these conflicting objectives.

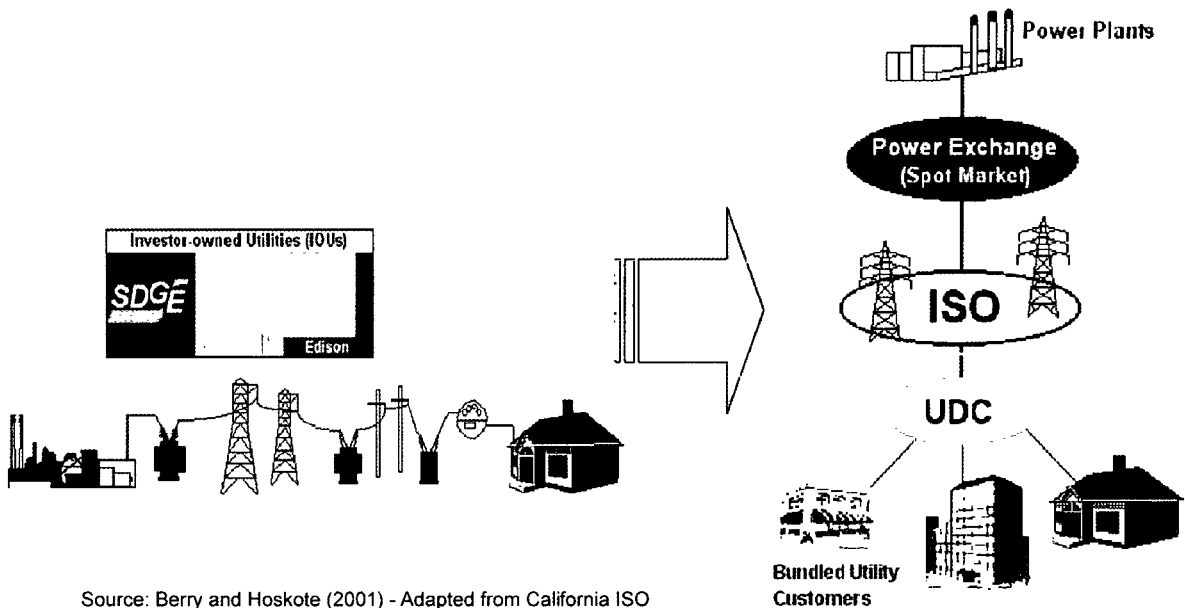
4.1 New Market Structure

The reform established a new market structure (shown in Figure 1) that promotes competition. Separate markets were created for energy, transmission and ancillary services that are procured every hour at market-priced rates through pool-based transactions. Bilateral transactions are also allowed for some participants in the market. The structure was designed to avoid imposing administratively determined commitments, such as capacity obligations, on market participants.

This new market structure was established by the following means:

- A Power Exchange (Cal PX) was created by January 1998. Cal PX is set up as a non-profit public benefit corporation under California legal statutes. It acts as a market place in

Figure 1. Electric Supply in California



Source: Berry and Hoskote (2001) - Adapted from California ISO

which generators and suppliers compete to meet demand for electric energy. It functions as an auctioneer and as such does not engage in energy trading on its own account. To ensure the viability of Cal PX, the AB 1890 statute requires the IOUs to sell energy produced from their own power stations (mainly hydro and nuclear) and purchase energy on behalf of customers who had not changed to another supplier (nearly all customers) from the PX during the four-year transition period to 2002. Their retail arms—called Utility Distribution Companies (UDCs)—and electricity marketers purchase energy from Cal PX and resell electricity to their customers.

- An Independent System Operator (Cal ISO) was established to operate the statewide transmission system impartially for buyers and sellers of bulk electricity. Any supplier that meets the regulated reliability standards has access to the system. Cal ISO operates as an independent, non-profit agency. It does not own any

generation, transmission or distribution systems, and relies entirely on services supplied from its markets to meet the demands on the statewide power system.

- The IOUs continue to own the transmission facilities and receive a fee for the use of these facilities. The Federal Energy Regulatory Commission (FERC) regulates these transmission use fees and the Cal ISO system operation fees, as well as many of the operating, commercial and technical protocols of Cal ISO and Cal PX.
- Other than the three Californian IOUs, participation in Cal PX is voluntary for all buyers and sellers of bulk power such as municipalities, IPPs and out-of-state producers. They can trade electricity using a variety of means (e.g., bilateral contracts).
- The non-PX participants must submit schedules with the Cal ISO through entities known as scheduling coordinators (SC). The SCs are the only point of contact between these

participants and Cal ISO, and they number around forty. They coordinate scheduling activities continuously, and each SC submits a “balanced” schedule to the Cal ISO in which the quantity of energy supplied equals the quantity demanded. Cal PX also submits a day-ahead schedule to Cal ISO.

- PG&E and SCE were required to sell at least 50 percent of their generation plants to IPPs or to place them in separate new companies, in order to mitigate their market power by reducing their scope for anti-competitive “self-dealing.” SDG&E was required to divest all its generation assets (but its parent company was allowed to merge with the local gas supplier). The capacity sold amounted to about 7,500 MW by PG&E, 10,600 MW by SCE, and 2,200 MW by SDG&E, totaling 20,300 MW. Hence ownership of about 40 percent of the total installed capacity in California was transferred to IPPs.
- A California Energy Market Oversight Board was established comprising members appointed by the state governor and legislature, in addition to large stakeholder governing boards for the Cal ISO and Cal PX.

4.2 New Market Operating Arrangements

The reform established separate markets for electric energy, ancillary services, and congested transmission capacity that are operated in parallel by Cal ISO and Cal PX according to market operating procedures approved by FERC. They were launched in April 1998 (except for the Block-Forward market, which was launched in July 1999). They are operated as auctions carried out

sequentially throughout the day, with bids for demand and supply. The final price is the highest supply bid that is accepted to clear the market.

- The energy market is structured primarily as a day-ahead auction by Cal PX, with bidders allowed to submit different quantities and prices for each hour. This auction is accompanied by hour-ahead auctions for energy to allow for divergences in demand or supply from the day-ahead bids. Such divergences may occur from unexpected changes in weather conditions or generating plant availability.
- The day-ahead and hour-ahead markets are independent and are closed separately. Upon closing, the winners are financially and operationally obligated to provide the services that are selected by Cal ISO.
- Since scheduled transactions seldom match the actual load on the power system, Cal ISO calculates, in real time, the amount of energy needed to balance total system demand. It conducts a real-time auction for providing supplemental energy or for backing off demand to achieve this balance. Bidders submit prices up to 45 minutes prior to the start of each operating hour. They indicate the prices at which they are willing to change their generation or purchases in real time. Cal ISO uses these bids to balance total generation and load in real time. Prices are established in this market every five minutes.
- Upon certification by Cal ISO, SCs can participate in any or all any of the day-ahead, hour-ahead, and real-time markets. SCs are not required to schedule all of their expected load and

generation in the day-ahead market. They may elect to bid for less than their expected load in the day-ahead market, and then cover their remaining load in the hour-ahead energy market. Deviations from their day-ahead or hour-ahead schedules are allowed by Cal ISO, and settled on the basis of real-time energy imbalance market prices.

- Every day, Cal ISO collects energy schedules from the SCs and assesses the viability of each schedule. Individual schedules accepted by Cal ISO are aggregated into a master schedule that is checked to ensure that it can be accommodated by California's bulk power grid in a reliable and safe manner. If Cal ISO identifies power system problems such as congestion in parts of the grid, it provides the markets with an opportunity to adjust schedules in order to alleviate the problems.
- Cal PX operates a Block-Forward market that allows participants to enter into electricity supply contracts for physical delivery up to six months into the future. These contracts provide a hedge against spot-market price volatility.
- Cal ISO purchases ancillary services (for black starts, frequency control, spinning, non-spinning and replacement reserve generating capacity available at short notice) in an unbundled manner from generators through long-term contracts and competitive bidding.
- Cal ISO ensures reliable operation of the transmission grid by holding an auction for allocating congested transmission capacity among the various system users after Cal PX has established preliminary hourly day-

ahead prices for energy. To facilitate this allocation, Cal ISO accepts "adjustment bids" for both the day-ahead and hour-ahead markets. These bids reflect the prices at which SCs are willing to procure more energy or curtail loads from their preferred schedules. If market participants do not submit sufficient adjustment bids, Cal ISO levies a congestion management charge on the schedule that utilizes congested transmission lines.

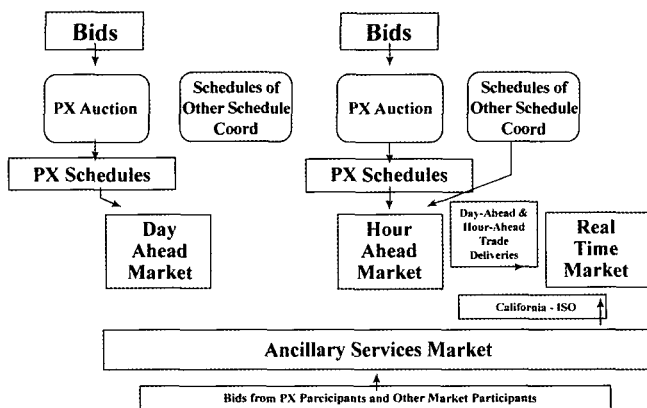
- Generators receive no capacity payments or payments for start-up costs in the energy market. Hence they must recover their fixed costs through direct payments received for energy on Cal PX sales, as well as through the Cal ISO ancillary services market.
- Open and flexible scheduling opportunities are characteristic of the market framework. For example, a generator may bid into multiple Cal ISO markets and have multiple delivery points. It can have a bilateral transaction with another market participant, sell a portion of its output to Cal PX, sell another portion to the Cal ISO ancillary services markets, and export a part of its output out of state.
- A generator faces a complex set of decisions concerning whether to sell capacity into an earlier or later auction, as well as between selling it for energy or ancillary services. Each decision to sell potentially forecloses opportunities to sell into other markets. For example, a sequence of decisions facing a generator could be whether to bid (1) into the day-ahead energy market at 7 a.m., for which the results are declared about one-and-a-half hours later; (2) into the ancillary

services market at 11 a.m., for which the results are declared by 1 p.m.; or (3) into auctions throughout the day in the hour-ahead and real-time energy markets. Market participants have the opportunity to place bids up to five hours before power flows in the Cal PX day-ahead market, two hours ahead in the Cal ISO hour-ahead market ancillary services market, and 45 minutes ahead in the Cal ISO real-time imbalance energy market.

- Apart from these centralized markets, there are separate bilateral transactions involving parties such as Californian generators who are not obligated to trade through the Cal PX, out-of-state generators and Californian buyers other than the three UDCs.

- *Commitment of the contractually agreed capacity with Cal ISO for a specified term (generally one to two years) of power plants sold by the IOUs as “Reliability Must Run” (RMR) to maintain system stability and to overcome local congestion on the transmission system.* “RMR” designation for a generating unit means that the owner must commit to maintaining the unit and to responding on a best-efforts basis to a directive from Cal ISO to operate the unit. The owners of RMR units are required to bid all of their contracted capacity into Cal PX. Hence they do not participate fully in the Cal PX market. Ironically in view of the events during 2000, Cal ISO designated RMRs soon after the new market started because of concerns about ultra-low clearing prices in its imbalance market. In this situation, the relatively high-cost thermal power generators in southern California would not win business in the market and therefore have little incentive to participate in it. Cal ISO was concerned about the availability and dispersion of sufficient reserve capacity so that the transmission system could absorb the loss of major transmission lines between northern and southern California.

Figure 2. Overview of Market Operations



Source: Berry and Hoskote (2001) - Adapted from California PX

The market operating arrangements are depicted in Figure 2.

4.3 New Market Regulatory Framework

The reform changed the way the power market is regulated as follows:

- *Introduction of a competitive transition charge (CTC) on customers' electricity bills for the recovery of the IOUs' stranded costs arising from the introduction of competition.* These costs refer to the relatively high operating costs and debt-service obligations (usually referred to as *stranded costs*) for some of the IOUs' generating plants built before the 1990s. The CTC is computed for each user's bill as the difference between the regulated rate

and the cost of supply. The regulated rate is frozen for all retail users until the IOU that serves them has recovered its stranded costs under the CTC. California's utilities had recovered more than \$11 billion under the CTC by the summer of 2000, and SDG&E had fully recovered its costs so that its rates were unfrozen. The transition cost-recovery period lasts up to December 31, 2003, after which retail sales are no longer frozen by statute.

- The CTC is also used to help recover the high costs of power procured by the IOUs under PURPA-mandated contracts with certain renewable generation and co-generation facilities (termed qualifying facilities, or QFs). These QFs provide up to 30 percent of the electricity produced in California. This high proportion reflects the state's aggressive pursuit of electricity from these types of facilities during the 1980s. The high prices (averaging around 17 U.S. cents per kWh) paid to the QFs under the terms of these contracts would make these plants uncompetitive under anticipated market conditions (i.e., conditions that prevailed before 2000) without the CTC. The prices in many of these contracts were tied to CPUC predictions of world oil prices, but these predictions proved to be inaccurate.
- *Imposition of a 10-percent rate reduction for all residential and small users from January 1, 1998, to last for four years.* This reduction was funded by the issuance in December 1997 of \$6 billion worth of 10-year rate-

reduction bonds by a special purpose trust authorized by the state.

- *Regulation of the distribution component of retail tariffs for the UDCs* will be based on performance-based rate-making.
- *Initiation of retail competition.* Suppliers have competed actively for the business of large commercial and industrial users. Retail competition has not progressed beyond 2 percent of the market in the market for residential users (except for a niche market for "green power") because of the freeze on retail rates and the inclusion of the CTC in customers' electricity bills.
- The California Public Utilities Commission (CPUC) continues to regulate the UDCs' distribution activities.

In addition, fossil-fueled power generation is subject to strict and a rather unique environmental regulation that pre-dates the 1996 power market reforms. In particular, a Regional Clean Air Incentives Market (RECLAIM) for Nox. Retail Emissions Credits, or RTCs had been established with the total allowed emissions in a district to be lowered over time so as to reduce urban smog. Regulated firms are allocated a fixed number of RTCs for NOx emissions for each year, and they are required to redeem these RTCs according to the amount of their NOx emissions. Regulated firms can buy RTCs from other firms to overcome a shortage for meeting their requirements, and sell RTCs in excess of their needs. These trades set up a market in RTCs, both for the current year and for future years ("vintages") in order to prevent a "NOx spike" of higher-than-anticipated emissions. Firms are not allowed to combine RTCs of different vintages.

5. Main Factors that Led to the Crisis

The California crisis centered around the three UDCs and their suppliers through the Cal PX. Other power entities, such as the municipal utilities that chose not to participate in the Cal PX, have not been so affected by crisis. This difference indicates that design flaws in the Cal PX market are a major source of factors that led to the crisis.

Nevertheless, a number of factors exogenous to the market design worsened the problems created by the design flaws. In particular, the crisis arose out of an unpredicted combination of events. Undoubtedly the most important was the shortage of power supply relative to demand. In the summer crisis, demand increased to around 51,400 MW—30 percent above the winter level. In the winter the supply capacity was reduced by more than 20 percent as thermal plants were taken out of service for deep maintenance, and an unusually dry end to the year 2000 in the Pacific Northwest left reservoir levels low and thus limited the amount of hydropower that California could import. The other factors have exacerbated this problem.

5.1 Market Design Flaws

Structural and operational flaws in the California power market became evident within a year after the ISO and PX went operational in 1998:

- *A mismatch between the regulated retail market and the deregulated wholesale market.* While wholesale electricity prices and natural gas prices are deregulated, retail electricity prices are fixed for the UDCs until they have recovered their stranded costs through the CTC or by December 31, 2003,

whichever is sooner. Hence increases in wholesale power costs cannot be passed through to retail users, thus exposing the electricity distributors to huge potential losses under their obligation to serve their customers. This flaw does not become serious unless wholesale prices rise above the retail rates, which they were not expected to do at the time that the reform was being introduced. This flaw may be only transitory, but it has contributed to the onset of the crisis during the transition period.

- *Lack of economic incentives for adequate capacity to maintain supply reliability standards.* The UDCs were not obliged to contract capacity, nor were generators recompensed specifically for providing capacity. Long-term forward contracting of energy by the UDCs was also not allowed. Finally, the lack of forward energy markets for some years ahead suppressed the price signals that would have helped the distributors and investors in generating capacity to assess the need for new capacity.
- *Lack of risk-mitigation options for distributors.* The UDCs were not allowed full access to forward markets, and so were not able to develop a risk-minimizing power portfolio. During 2000 they acquired only about 6 percent of their energy from forward markets, in contrast to 34 percent from their own generating plants and 60 percent from other suppliers on the Cal PX market. They were not even allowed to sell their power plants with long-term vesting contract protection against price volatility. Instead, they have had to rely on volatile spot markets. Hence, they were forced to “sell long and buy

short,” which is disastrous for a trader in any commodity.

- *Demand inelasticity.* Lack of demand elasticity by UDCs in the energy markets arises from their inability to curtail their demand to avoid paying high prices, because of their obligation to serve the demands of their captive customers. Just as a relatively small amount of tightening of the supply/demand balance in the absence of any demand elasticity produced the summer price spikes in the Cal PX market, so a relatively small amount of loosening of the supply/demand balance in the presence of some demand elasticity would have significantly mitigated the pressures that produced price spikes.
- *Price caps.* Facing virtually no supplies in the real-time balancing energy market to meet system imbalances, the Cal ISO was authorized by FERC to impose during 2000 progressively lower “soft” price caps on bids in the real-time balancing energy market, starting at \$750/MWh during the summer and dropping to \$250/MWh by the end of the year. Payments made by the UDCs above the price cap would be subject to scrutiny and cost-justification by Cal ISO in retrospect. These levels would amply cover the costs of power generation under normal trading conditions, but \$250/MWh was insufficient to cover even the variable operating costs of the older power plants during the periods of very high gas prices and high costs of NOx emission permits. The situation appeared to provoke generators into raising their bids for supply during off-peak periods to recover their losses under the price caps during peak periods. These caps also appeared to

limit prices to below the opportunity costs of other units providing replacement reserve, hydro units constrained by lack of water, and thermal units constrained by emissions limits, as well as exporters to neighboring markets which were also experiencing high prices.

- *Market arbitrage by generators.* Since the markets for energy, transmission congestion rights and ancillary services are cleared sequentially, rather than together, Cal ISO faces heavy demands on coordination to prevent arbitrage by market participants that leads to inefficient dispatch of generating plants and higher prices than predicted under models of these competitive markets. This sequencing gives incentives to generators to collect high premiums for real-time energy and ancillary services by withholding supply (or by putting in such high bids as to be sure that they won’t be accepted) from the day-ahead energy market, and then bidding more supply into the other markets. Such profit-maximizing incentives for generators bidding into these multiple markets may account for some of the observed price spikes under supply shortages during 2000. For example, a generator would set a bid in the energy market for a segment of capacity to cover at least the foregone expected earnings in the ancillary services market for that segment, and this bid could be a very high hourly rate to cover these foregone earnings if the generator expects the segment to be dispatched for only one or two hours in the energy market. Likewise, prices in some markets for ancillary services could be driven up by considerations of foregone earnings in markets for

other ancillary services. Some observers also allege that the repeated rounds of bidding under the market structure provide generators with scope to “game” the system by adjusting their bidding strategies to their advantage merely by observing each others bidding behavior without collusion in the accepted legal sense.

- *Market arbitrage by UDCs.* Since the Cal PX capped prices in the day-ahead energy market at a much higher level (\$2,500/MWh) than the Cal ISO’s cap in the real-time balancing market, the UDCs have kept down their demand purchases in the day-ahead market by under-scheduling their during hours when price spikes would otherwise be likely to occur. They have done this to keep the price in this market below the cap in the real-time balancing market, thus effectively capping the rate they pay at the lower level of the latter. Purchases on the real-time balancing spot market have constituted a higher proportion of total traded energy in Cal PX (20–30 percent of the total energy procured) than in other U.S. states and other countries that have forward contracts in their power markets, since a balancing market usually handles less than 5 percent of total trade. This feature appears to have contributed significantly to the large volatility in prices in Cal PX.
- *Market power.* The potential for market power is likely to exist in a deregulated price-bid market such as the California wholesale market, especially in the presence of local market segments created by transmission constraints. This potential takes the form of artificial scarcity of power created by power generators to drive up prices and earn huge profits. The potential for abuse of market

power by generators increases significantly during periods when supply falls short of demand. Some experts contend that the generators’ exploitation of market power caused a significant portion of the huge price spikes for a few hours during 2000 in the California wholesale electricity market. Others go further by alleging persistent and serious abuse of market power by generators. Likewise, some observers allege that common ownership of one of the main gas suppliers and critical gas pipeline capacity in southern California created the conditions for market power in this market. After auditing plant outages in California, however, FERC staff stated that they did not find evidence of certain practices that indicate abuse of market power by the audited companies. It is generally acknowledged that it is difficult to distinguish from available data the exercise of inappropriate market power from the exploitation of legitimate scarcity rents when a market is in short supply.

- *Market governance.* Poor governance structures contributed to the problem. The large size and politicization of the boards of Cal ISO and Cal PX, through quotas of stakeholders each representing their own interests, hampered attempts to focus on getting the market to work. The governance arrangements for Cal PX give to some parties the voting power to block changes to market rules, which was done out of concern about putting market power in the hands of the UDCs. This led to the prohibition of trading on forward markets by the UDCs. Likewise, it is alleged that generators have too much power in Cal ISO, which they have used to

block proposals to force them to schedule their entire output in the day-ahead market. In late 2000, FERC ordered the replacement of Cal ISO's stakeholder board by a non-stakeholder board.

- *Retail competition.* Less than 2 percent of California's retail electricity users have migrated from the incumbent UDCs to alternative Energy Service Providers (ESP). Most ESPs have exited the California market after their failure to attract customers. The failure to develop retail competition in California results from a policy of charging retail users a default price equal to the wholesale power price, rather than the retail market price, and by allowing the UDCs the right to provide default service. Default service refers to electricity supply provided to those customers that are not receiving service from a competing supplier. It is a regulatory device used to smooth the transition to a competitive retail market or as a long-term alternative to it. The amount by which the default service price exceeds the wholesale price dictates the level of customer savings and supplier earnings, which are fundamental drivers of retail competition. Generally, the higher the default price relative to the wholesale price, the more intense the competition and switching to new suppliers.

The presence of these flaws raises the issue of how the process for reforming the California market was managed. A consensual process was adopted, so that interested parties influenced the design in ways that possibly caused these flaws. This process resulted from the difficulty in changing market structures when (1) the

ownership of the means of supply is diversified among private interests that possess property rights by virtue of their ownership and (2) other parties, such as consumer and environmental advocacy groups, have the legal right to mount strong legal challenges in defense of their interests, as in California.

5.2 Exogenous Factors

Constraints on Expanding Supply

- No new power generation capacity has been commissioned in California since 1992 because (1) uncertainty about the new power market deterred investors until the new market structure and regulations were finalized in 1996, and (2) subsequently excessive delays occurred in obtaining siting permits for new power stations in the face of local opposition when investors submitted applications.
- Investors have been deterred from entering the California power market by the expense and uncertainty of the extenuated permitting process for new power stations and transmission lines, exacerbated by the ability of people dwelling in the vicinity of the proposed facilities to initiate numerous legal challenges. The propensity of California's consumer and environmental groups to use ballot measures to oppose new power plants has added to the delays and uncertainty for investors in these plants. However, in the last two years the state has licensed nine new power plants (totaling 10,600 MW), and five (totaling 2,900 MW) are under construction. These plants will contribute significantly to easing the

- supply shortage, but only in about two years' time.
- A drop in imports of power from neighboring states occurred because of low hydropower production caused by a drought and a growth in demand for electricity in these markets. Environmental safeguards to protect fish populations in the Pacific Northwest region further limited the water available for generating electricity. These imports formerly provided an important source (20 percent) of California's power needs, especially during the peak demand period in summer months.
 - Power stations and transmission facilities are old. Nearly 60 percent of California's power plants are at least 30 years old, and now need more maintenance and thus longer outage periods than modern power plants. The withdrawal of about 10,000 MW of this plant for maintenance, as usual during the low-demand winter period, helped create the end-2000 supply shortages.
- Demand for electricity in the summer of 2000 was pushed up by air conditioning loads under the highest temperatures for May to July recorded for 106 years.
 - Retail demand was not sensitive to increases in the costs of wholesale power since the tariff rates for most consumers in California were frozen until the utilities collected all their stranded costs under a regulated surcharge on customers' electricity bills. In addition, lack of demand elasticity by retail electricity buyers arises because they only discover the prices that they are paying after the transaction, and then only in terms of an average monthly price rather than hour-by-hour prices. Relatively few users have time-of-use (TOU) meters.
 - Failure to meet demand reliably for electricity—especially through blackouts and brownouts—is enormously costly for power users who have already adjusted to using grid power. Californian users of electricity showed their willingness to pay huge penalties under interruptible supply contracts rather than reduce power consumption when called upon to do so by their suppliers.

An Unexpected Increase in Demand

- The growth of Internet-based power consumption based on Silicon Valley industries spearheaded a 25-percent increase in statewide demand during the 1990s, but this statistic hides the real problem. From 1988 to 1998, electricity demand grew at an average rate of only 1.3 percent per year. In 1999 and 2000, however, electricity demand on the Cal ISO system surged unexpectedly. In June 2000, energy demand was 12.5 percent higher than in June 1999, and peak demand was 6.2 percent higher.

A Steep Increase in the Cost of Wholesale Power During 2000

- The market clearing price in the day-ahead Cal PX energy market oscillated between \$25 and \$50/MWh during 1998, 1999 and the first half of 2000, and then rocketed to over \$150/MWh in June, July and August 2000 during an extreme heat wave. The steep increase in price occurred when supply started to fall below demand, even though prices did not move

discernibly beforehand as the margin diminished between supply and demand. Electricity markets do not have the price stabilizing mechanism of buffer stocks because electricity cannot be stored economically.

- The average price of natural gas across the country also shot up during 2000 due to growth in demand, because gas is the fuel of choice for the huge amount of power-generating capacity recently commissioned or under construction. The shortage also reflects a slowdown in gas exploration during the second half of the 1990s, when oil and thus gas prices were low. This price increase occurred when much more gas was used in 2000 than in 1999 for generating power in California because of higher demand for power and lower supply from other power-generating sources.
- The price of natural gas in California reached extraordinarily high levels during a spell of cold weather in December 2000 (gas is used for space heating as well as power generation). In December gas sold daily on spot markets at major terminals averaged around \$11 per thousand cubic feet (TCF), compared to around \$2.5/TCF in the preceding years. This increase in gas price added about \$75/MWh to the operating cost of a typical old power plant in Southern California that was supplied with gas bought on the spot market. Daily prices reached at times more than \$60/TCF at the southern border of California during the first week of December 2000, partly due to bottlenecks in the California gas pipeline system. However, a large proportion of gas purchases by gas traders and suppliers was hedged, and hence they were less exposed to gas price volatility than

UDCs were to electricity price volatility.

- The design of NOx emission regulations—restrictive levels of annual emission permits complemented by a market for emission credits—has caused owners of older generating plants in California to pay a high price for these credits. Given power supply shortages, these plants were under pressure to utilize their capacity above the level that would allow them to meet the NOx emission standards. In the South Coast Air Quality Management District of California (SCAQMD), the allowed NOx level was reduced on July 1, 2000, which reduced the supply of NOx RTCs just when demand for them increased. Consequently the cost of a vintage 2000 RTC increased from around \$3/lb. NOx between 1997 and mid-2000 to around \$45/lb. NOx by end-2000. This increase in price for NOx emission credits pushed up the variable operating costs of a typical Southern California power plant by around \$30/MWh.

5.3 Exodus of Funds by Utilities

The holding structure adopted by the three IOUs has enabled these companies to keep substantial funds out of reach of the creditors of the UDCs as the latter's debt mounted through 2000. If they had been available, these funds would have been sufficient to defer the current financial crisis, and thus to provide some time for implementing corrective measures to prevent the development of the financial crisis. From the mid-1980s, the CPUC authorized the creation of holding companies, in which the utilities were relegated to the status of subsidiaries. The parent companies were permitted to pursue

other, unregulated businesses as long as those activities did not compromise the utilities' ability to serve customers or the capital needs of the utilities.

Independent audits of SCE and PG&E released by the CPUC recently showed that the UDCs transferred billions of dollars to their parent companies during the first years of deregulation. The parent of SCE received \$4.8 billion and the parent of PG&E received \$4.6 billion between 1997 and 2000 from their Californian utilities. These funds were derived from the sale of their Californian generating plants, the surpluses earned through the sale of power in Cal PX from their remaining generating plant, and the recovery of stranded costs under the CTC. The parents used this cash to finance most of their dividends and for the acquisition or construction of power generating capacity in other states and abroad. The parent companies of these UDCs have instituted so-called ring-fencing provisions designed to prevent bankruptcy courts or anyone else from using the parents' unregulated assets to cover the debt of the UDCs. These steps have aroused considerable controversy in California.

6. Could the crisis have been avoided?

In assessing the impact of the design of the California power market on the current crisis, the issue is whether design flaws have made a serious situation unmanageable. The fact that this arrangement worked without major trouble for the first two years indicates how easy it was to fall into a false sense of security while market fundamentals were heading for a crisis. In the case of California, these fundamentals were strongly rising demand, no new capacity, decline in hydropower output, and surging natural gas prices. Once the crisis hit the market, the

opportunity for making adjustments smoothly had been lost and the impact was magnified by the flaws in the market design.

Other states experienced spikes in wholesale electricity prices similar to those in California, but only for a few days at a time. Only California experienced a persistent series of such spikes throughout the summer of 2000. Retail prices in some other states have also risen by similar proportions to the trebling of rates in the San Diego area. Likewise, natural gas prices have risen on average by similar amounts across the United States, although they have risen much more at times in parts of southern California due to pipeline congestion. But the other states have not experienced the brownouts and financial crisis that afflict California.

Two avoidable design flaws stand out:

1. UDC's unhedged exposure to spot prices, especially when tight supply conditions were foreseeable. The regulators eventually tried to help the UDCs diversify this risk, as described immediately below, but their efforts appeared to be a case of "too little, too late."
2. Retail prices capped at levels that depended on low prices in the wholesale power market for sustainability. Despite intense political and consumer opposition, the CPUC has recently approved an emergency rate increase of 9 to 15 percent to relieve some of this pressure.

The utilities could have tested the proposed structure in the market before taking irreversible steps, for example by offering their generating plants for sale with vesting contracts on terms that were affordable under the capped retail prices. A lack of takers from IPPs for such contracts would

have indicated that the proposed structure was unsustainable.

The higher-than-expected prices that the IPPs paid for the IOU's generating plants possibly indicated that they expected spot prices to be much higher than the levels at which the UDCs could survive within the capped retail rates. Other explanations for these high observed prices are the potential value of generation capacity on the plant's site, and the expectation of obtaining major gains in operating efficiency.

After experiencing extreme (up to that time) price spikes during the summer of 1998 shortly after Cal PX opened, SCE sought CPUC's permission to buy 2,000 MW—about 10 percent of the peak summer demand of its customer base—outside the Cal PX. This move was opposed by consumer groups, electricity sellers and other stakeholders. CPUC rejected SCE's request on the grounds that such purchases would weaken Cal PX and put the smaller electricity sellers at a competitive disadvantage on the Cal PX.

Cal PX tried to help the UDCs protect themselves from price fluctuations by offering forward contracts for up to 18 months in April 1999. CPUC gave the UDCs permission to enter into such contracts, with limits on how much electricity they could buy that way, and so Cal PX opened its Block-Forward market in July 1999. As prices kept rising, the UDCs asked for more, and CPUC generally granted these requests, sometimes months later. In July 2000, PG&E asked CPUC for emergency authority to buy power outside Cal PX, which CPUC approved in August in the face of the full-blown crisis.

The UDCs sometimes hesitated to use their freedom fully to enter into such contracts because of concern about CPUC's ability to cut their profits later in a "prudency review"

if it deemed the contract terms unacceptable. This might occur if spot prices dropped below the level of prices under long-term contracts before the contracts expired. So both options open to the UDCs were risky, and generally the spot market was chosen by them.

The market based NOx credit trading system, whose perceived advantage is reduction in the cost of achieving compliance for the industry, in fact appeared to contribute to the increase in marginal supply costs of electricity when supply was constrained in the Summer of 2000. For example, "NOx spikes" can occur on days when electricity demand is greatest (due to air-conditioning load, for example), because electricity spot prices can then rise sufficiently to encourage plant operators to pay high prices for NOx RTCs so as to run power plants at maximum output. This indicates the possibility of interaction between environmental and energy costs when both are determined by market clearing prices.

Inadequate transition arrangements also appear to have contributed to the crisis. The Californian "big-bang" approach to deregulation is open to the risks of unexpected market conditions, as well as the unexpected ability of participants to "game" the market. Market rules and highly sophisticated software, hardware and telecommunications systems were developed in only 12 months, completely independently of any market participants. A structured transition strategy is needed that is based on planning for steps that might be taken if crucial assumptions, such as continuation of surplus power supply capacity and low natural gas prices, proved to be wrong. In particular, the IOUs mistakenly anticipated earning huge margins during four competition-free years in which to recover their stranded costs. Cal ISO was

forced to make ad-hoc adjustments such as introducing price caps to deal with these unexpected events; these adjustments provided quick fixes but led to further problems.

California's inclination to rely on power imports, rather than expand its own supply capacity, exposed it to developments beyond its control. Neighboring states object to being energy farms for California, whereby the latter avoids the environmental consequences of building new generation capacity while benefiting from the output. They are also unhappy about the increases in prices in their power markets that they attribute to events in the California market.

One indicator of whether California could have avoided its crisis by better market design is the existence of workable deregulation of a power market elsewhere under similar market conditions in the United States such as in Pennsylvania, Texas and Illinois. Another indicator of California's specific vulnerability is the experience of its neighboring states under similar supply constraints and growing demand. Wholesale power prices during the summer months of 2000 also rocketed in these states, partly due to the rise in California's wholesale power prices, but their utilities did not hit the severe financial crisis that has floored the state's main utilities.

In Pennsylvania, where the state restructured the electricity market with far less political influence on the design, the state PUC set a high cap on wholesale prices to secure an upper limit, and did not require utilities to sell their generation plants. Buyers and sellers are allowed to choose whether to exchange in the power pool or through direct contracts with financial hedging through "contracts-for-differences." A

capacity market exists in parallel with the energy market. They have not experienced the shortages faced by Californian power users for these reasons and also because the Pennsylvania power system benefits from extensive interconnections with other regional power markets; also, coal is widely used for power generation, which hedges against increases in natural gas prices. Independent power producers are developing nearly 40,000 MW of new generation capacity in the state. Retail competition is promoted by a high default cost (considered to be too high by some commentators) and by mandatory reallocation of retail customers from the incumbent suppliers, so that around 10 percent of customers have switched supplier.

Overall, three conclusions may be drawn from the California power crisis:

1. The flaws in the design of the California market contributed substantially to the financial crisis of California's main utilities.
2. Efforts to deal with the crisis in the presence of these flaws could not have succeeded.
3. A properly designed power market could have coped with the factors leading to the crisis. Because the reforms already undertaken in the California power market prevent a return to the pre-reform structure, the state's only option is to correct these flaws and move forward to a better-designed market.

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