California's Flawed Market
What Went Wrong and How to Fix it

By Fereidoon P. Sioshansi*

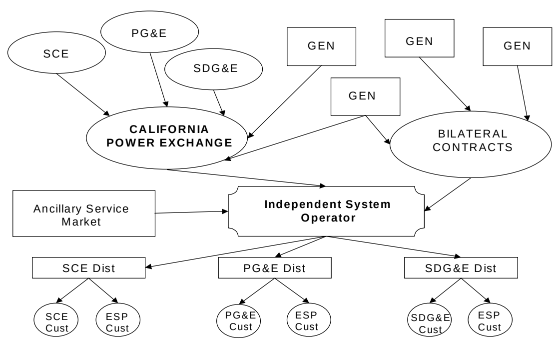
California's Grand Experiment in ESI Restructuring

California was among the first states in the United States to radically restructure its electricity supply industry (ESI) with the passage of a sweeping legislation, Assembly Bill 1890 (AB 1890) in 1996. It opened the whole market to competition at once in April 1998. The interesting features of the California market include:

- Divestiture of at least 50% of generation by incumbent utilities;
- Creation of two new and independent entities, the California Power Exchanges (PX) and the Independent System Operator (ISO);
- Fairly generous allowance for recovery of stranded costs using a competition transition charge (CTC) during a transition period not to exceed four years;
- A rate freeze until the stranded costs are fully recovered; and
- An automatic 10% bill reduction for all residential and small commercial customers.

The incumbent utilities, now called utility distribution companies (UDCs) were turned into conduits, through which customers could receive electrons from competing suppliers, called energy service providers (ESPs). UDCs were told to sell any remaining generation into the PX, and buy all the service needs of customers who choose not to switch suppliers from the PX (Figure 1). The UDCs were to re-sell power to these customers at the PX price, with no mark-up. They were also prohibited to engage in marketing – acting as silent service providers as well as provider of last resort. The policymakers envisioned a future where the UDCs would shrink over time to become passive poles and wires companies as increasing numbers of customers switched to alternative ESPs.

Figure 1
California's New Electricity Market



Generating plants sold to independent power producers (IPPs) were free to sell trough the PX, or to sell directly to customers in bilateral contracts as shown in Figure 1. There would be no regulation on how much power could be sold at the daily PX auction, unless there was evidence of price fixing or collusion. With a number of generators vigorously competing, it was felt that the wholesale market would self-regulate (Table 1). Customers who switched to ESPs would continue to receive distribution service from regulated UDCs. The two independent entities, the PX and the ISO were seen as important pillars of the new market. Everything looked set for a good start.

Table 1
Major Generators in the Golden State
Capacity of major generators with assets in California*

Company	Capacity (MW)	Market Share
Pacific Gas & Electric	7,386.46	24
Los Angeles Dept of Water & Power	4,914.50	16
AES Corporation	4,818.51	16
Reliant Energy	4,018.86	13
Southern California Edison	3,421.00	11
Duke Energy	2,763.50	9
San Diego Gas & Electric	1,216.30	4
Sacramento Municipal Utility District	828.10	3
Northern California Power Agency	644.60	2
FPL Energy	227.92	1
Others	490.12	2
Total	**30,729.86**	

** There are a number of major out-of-state generators that are active in the California market in addition to those listed here. Consequently, the market shares suggested by these figures are actually exaggerated.*
SOURCE: California Energy Commission

For the first two years of operation, things went relatively smoothly. Customers had a choice of suppliers, although the percentage of switchovers remained low among residential consumers (Table 2). Small commercial and all residential customers were getting an automatic 10% bill reduction and were not much interested to experiment with new ESPs with unfamiliar names and nothing convincing to offer. Vigorous competition ensued for the large industrial and commercial customers, resulting in a significant percentage of the load abandoning the UDCs.

Customer Switchovers in CA Compared to a Few Other Jurisdictions

Table 2
Who Is Switching Suppliers?
Customer Turnover in Selected States

	By # of Customer Accounts			By Customer Load		
State	**Resid**	**C & I**	**Total**	**Resid**	**C & I**	**Total**
California	1.4%	3.5%	1.7%	1.6%	18.8%	13.1%
Massachusetts	*	2.4%	0.3%	*	NA	11.0%
New York	1.0%	2.7%	1.3%	1.0%	10.4%	7.9%
Pennsylvania	8.3%	16.1%	9.1%	8.7%	41.7%	28.7%

** There has been virtually no switchovers in the residential market in Massachusetts thus far due to regulatory price rigidities. C&I = commercial and industrial customers.*
SOURCE: William R. Huss, Xenergy, Inc.

Both the PX and the ISO ran smoothly, with the exception of a few minor hiccups. Prices remained generally low during two mild summers in 98-99. The PX prices closely followed the generators' estimated marginal cost of generation for the great majority of the hours (Table 3). During peak demand periods, when supply approaches available capacity and reserve margins are low, PX prices exceeded estimated marginal costs, but not by an overwhelming amount. Observers generally gave

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decent marks to the competitive generation market.

Table 3
PX Prices and Estimated Marginal Cost of Generation
Not Perfect, But Tolerable
PX's market clearing price (MCP) and the estimated marginal cost of generation
June - September, 1998

Month	Period	PX MCP ($/MWh)	Marginal Cost ($/MWh)
June	Midnight - 6 am	$2.63	$2.63
June	6 am - Noon	$12.04	$12.00
June	Noon - 6 pm	$20.13	$19.30
June	6 pm - Midnight	$13.56	$13.52
July	Midnight - 6 am	$17.64	$17.46
July	6 am - Noon	$26.15	$23.21
July	Noon - 6 pm	$51.72	$28.40
July	6 pm - Midnight	$34.14	$26.36
August	Midnight - 6 am	$22.50	$22.46
August	6 am - Noon	$31.76	$26.82
August	Noon - 6 pm	$67.17	$31.97
August	6 pm - Midnight	$38.67	$29.01
September	Midnight - 6 am	$22.72	$22.68
September	6 am - Noon	$30.18	$26.57
September	Noon - 6 pm	$49.22	$30.14
September	6 pm - Midnight	$33.81	$22.70

SOURCE: Borenstein, Bushnell and Wolak, Diagnosing Market Power in California's Deregulated Wholesale Electricity Market,*University of California Energy Institute, March 99.*

Utilities were fast collecting their stranded costs through the state-endorsed competition transition charge or CTC, essentially a euphemism for a non-bypassable tax. Customers began receiving unbundled bills which showed the various elements of cost of service. Figure 2 shows one such example for a typical Pacific Gas & Electric (PG&E) residential customer, where the CTC and the other components are identified.

Figure 2
Typical Unbundled California Utility Bill
The Benefits And Complexities Of Restructuring
Sample bill for residential utility distribution company (UDC) customer receiving the legislatively mandated 10% bill reduction.

Total Charges	$78.19
Legislated 10% Reduction	7.82 -
Net Charges	$70.37

The net charges shown above include the following component(s). Please see definitions on Page 2 of the bill.

Electric Energy Charge	$0.04446/Kwh*	$38.59
Transmission		2.90
Distribution		22.13
Public Purpose Programs		2.78
Nuclear Decommissioning		0.35
Competition Transmission Charge (CTC)		10.40 -
Trust Transfer Amount (TTA)		14.02

This rate is based on the weighted average costs for purchases through the* ***Power Exchange**. This service is subject to competition. You may purchase electricity from another supplier. (Call 1-800-743-0040 for a supplier list.)*

SOURCE: Pacific Gas & Electric Co.

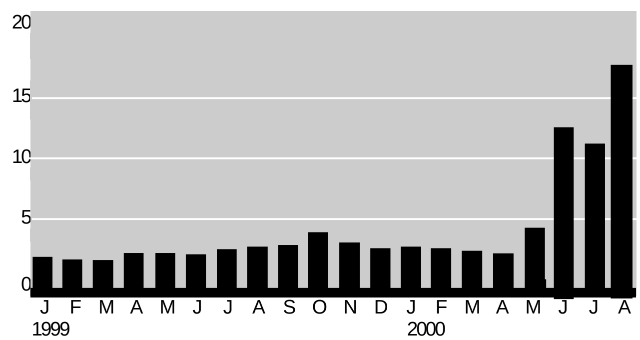
In fact, San Diego Gas & Electric (SDG&E), which did not have much to begin with, collected all its stranded costs early and was no longer subject to the mandatory rate freeze. It began boasting to its customers that they did not have to pay the CTC any more – as were the customers of the other two investor-owned utilities. It must, of course, be noted that the state's municipals and others, were not subject to the requirements of the AB 1890, and did not have to take part in any of this.

They were a few complaints, mostly from disgruntled ESPs who found the California's restructured market extremely tough to operate in. Many who entered soon left, saying that there was no way to remain viable given the rules of the market. But the lights stayed on, and small consumers were placated through the 10% bill reduction feature of AB 1890.

Summer Madness

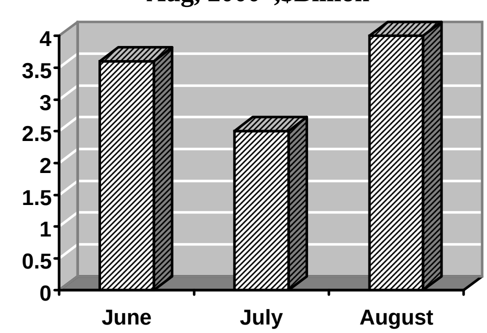
Then came the summer of 2000. Prices shot up to unusually high levels, and exhibited unprecedented (and largely unexplainable) levels of volatility (Figure 3). California paid nearly $4 billion for energy alone in the month of August, way over the previous two years (Figure 4).

Figure 3
Hot Summer's High Energy Prices
Average Monthly Wholesale Electricity Prices at the California PX, $MWh*



** These prices are pure* energy *prices and do not include the cost of reliability services which are added by the Independent System Operator.*
Source: California Power Exchange

Figure 4
Paying Dearly for Energy
Total Energy Costs in California, June, July, Aug, 2000*,$Billion



** Corresponding average monthly $/MWh prices were $167, $117, and $185*
Source: California ISO

Customers of SDG&E, who no longer had the rate freeze, saw monthly bills that were two and three times higher than normal. There were rolling brownouts in Silicon Valley. And

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the ISO was paying exorbitant prices to maintain system reliability. The generators were making lots of money, without violating any laws or doing anything overtly illegal. Consumers and politicians began to say that deregulation had failed and it was time to re-regulate the industry. Other states and countries that were following California's experiment with a mixture of disbelief and awe, are now wondering if they should proceed with their own plans to restructure their own markets.

Now, with cooler temperatures and cooler heads, everybody wants to know what went wrong, and – more importantly – how to fix the problems. Many useful lessons can be drawn from this experience for other states and countries considering market liberalization. This article examines the underlying causes leading to this past summer's unusually high prices, explains what went wrong, and suggests how the problems may be fixed.

Why the California Market Behaved so Badly this Summer

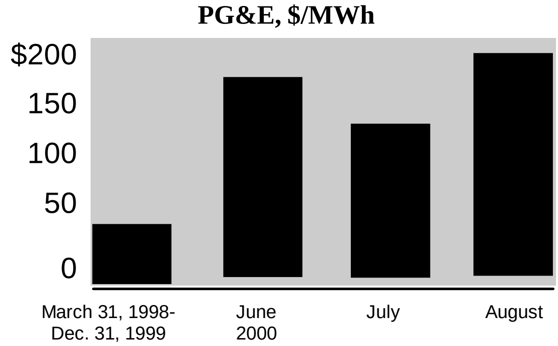
Before one can solve a problem, one must first define it. In the case of California, the problems experienced this summer are the symptoms of a flawed market. And the problems are many. Consequently no simple, single solution will do. What are the problems?

- High energy prices;
- Price volatility; and
- Lack of appropriate incentives to manage price volatility.

As shown in Figure 5, the average monthly wholesale electricity price for energy in the Golden State has been abnormally high this summer. Demand has been a little higher than last year's mild summer, but not enough to explain the difference, or so it seems.

Figure 5, however, is only part of the story. Adding the cost of reliability services (which are added on top of the PX prices by the ISO) makes the situation worse. The price tag for reliability during a 10 day period in June, for example, totaled $387 million (compared to $384 million for all of 1999). The Figure below shows what PG&E (and similar numbers for SCE) paid for power in June, July and August, compared to the average for the period covering March 1998 through December 1999. The figures for September, not final at the time of this writing, are expected to be in the same range as the previous three months. They have been running as high as $200/MWh on a few hot days in September

Figure 5
Not a Good Picture
Average Monthly Wholesale Electricity Prices Paid by PG&E, $/MWh



Source: PG&E

High prices like these add up quickly. In the month of August alone, California paid over $4 Billion for energy, exceeding previous records set in June and July (see Figure 4).

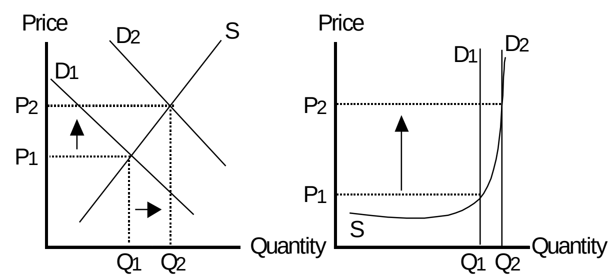
Why are the prices so high? That is the question everyone wants to know. Demand has been running a bit higher than last year, 7% higher in August of 2000 compared to 1999, for example. Is that enough to explain such steep price increases? The answer is that when demand approaches, or exceeds, available supply – which has regularly been happening in California this summer – the relationship between a rise in demand and price is no longer linear. Under such circumstances, a small increase in demand causes disproportionate increases in price.

This phenomenon is exacerbated by the artificial *in-elasticity* of demand, as shown in Figure 6. The graph on the left shows a *normal* market, with normal-looking supply and demand curves. In this case, an increase in demand (represented by an upward shift in the demand curve from D1 to D2) will result in somewhat increased price (from P1 to P2), assuming a fixed supply curve, S.

Elementary Economics

When demand is inelastic and supply constrained, prices go through the roof.

Figure 6



In the graph on the right, demand is shown as *perfectly inelastic* (i.e., a vertical line), and supply with a steep upper end, representing physical limitation of generation and/or transmission. In this case, even a small increase in demand, say 7%, will result in a disproportionate price increase – and virtually no increase in supply, since the system is running at or near full capacity. The latter graph is a reasonable representation of the extremely constrained California market.

How Can it be Fixed?

There are three fundamental *solutions* to California's electricity problem – as well as a number of necessary market rule changes. The three most important fixes are:

- Increase supply by building additional generation (and transmission);
- Make demand responsive to high prices; and
- Encourage long term, fixed-price contracts outside the PX.

The need for new generation is now widely recognized – even though by itself, this is unlikely to cure the problem. According to the California Energy Commission (CEC), 2,900 MW of new capacity is under construction, with another 10,600 MW in advanced stages of design and/or licensing. Another 30 proposals are under planning. But proposing a plant and bringing one on line are two different things.

The effect of bringing demand into play has been widely underestimated, and its impact on moderating peak prices vastly underutilized. CEC estimates that on a hot summer day, an incremental 5 degree F rise in mean temperature adds 8.5% to the peak demand – roughly 4,000 MW. Since 28% of power consumed in California during peak demand periods is consumed by the air conditioning load, equally divided among the residential and commercial sectors, the cure appears obvious. Yet the infrastructure to manage this peak load is currently very limited.

After this summer's price fiasco, the investor-owned utilities in the state are struggling to put programs into place in time for the next summer. Highly generous incentives are offered for curtailing the load when it really matters. The jury is still out as to how much of the potential may be captured.

Aside from these *physical* cures, there are *financial* options to cope with high prices and price volatility – through forward contracts and risk hedging. Although the markets for such instruments are currently immature and feeble, they can be expected to flourish in the next couple of years. The regulators should encourage such schemes. Until recently, utilities in California were effectively barred from reliance on financial instruments to manage price volatility.

Even now, the incentives to do so are poorly defined. For example, it is not clear if and how much of an insurance premium can be passed on to customers for offering long-term fixed prices by the incumbent utilities. Under these circumstances, risk-averse utility distribution companies (UDCs) cannot be expected to do much. Why should they offer fixed prices to their customers if they are unsure about passing on the risk premium?

There is also a list of what *not* to do. Price caps, rate freezes, and more regulations. Price caps, for example, have not traditionally worked in other markets such as rent or wage controls. Many of the problems affecting California's young market are because there are still too many regulations, and too many regulators. Markets have not failed, half-baked regulations have.

California Fiasco Reverberates Nationwide – Worldwide

Many policymakers in other parts of the United States, and other countries, who have been following this summer's fiasco in California, have had second thoughts. Why deregulate an industry that, despite many known shortcomings and perceived inefficiencies, appears to be working. Even if prices are not as low as they could be, at least they are stable, predictable, and *reasonably* low. Even if customers have no options to switch suppliers, there is at least one established, reliable supplier who can be relied upon to provide universal service to all.

Just in the last couple of months, a few states have expressed reservations about their own restructuring plans, and/or have announced postponements. New Mexico, for example, has decided to re-visit its 2002 start date. Oregon has devised and revised its own restructuring plans taking particular pain to avoid the mistakes of its neighbor to the South. The Oregon plan, which is scheduled to go into effect beginning October 1, 2001, will allow large industrial and commercial customers to choose an alternative supplier but will keep small residential customers under regulated rates.

The regulators have second thoughts because of serious questions about the costs and the problems associated with establishing new markets, with no guarantees that they would perform any better than the regulated ones they replace.

A number of industry observers are now of the opinion that most of the benefits of competition may be captured in the wholesale market. According to this line of argument, *retail* competition is simply not worth the bother.

The logic of this argument is simple. When considering all the costs and benefits of implementing competitive electricity markets, it is generally agreed that *most* of the benefits accrue at the wholesale level and are captured by large customers. By contrast, *most* of the costs result from extending choice to the small customers, for whom the benefits are small relative to the costs. If this is true, then why not limit customer choice to large customers (as proposed in Oregon) – and leave it at that – unless there are overwhelming reasons to extend it all the way to residential customers.

What are the costs of converting to competitive electricity markets?

- The implementation costs of new infrastructure, such as establishing competitive wholesale auctions and independent system operator (ISO) or regional transmission organizations (TSO);
- Significant costs in unbundling vertically integrated utilities and many of their internal systems;
- Costs associated with unbundling metering and billing functions and developing duplicative customer record-management systems; and
- Costs associated with monitoring market performance and compliance – in addition to maintaining the old regulatory bureaucracy to watch over the regulated monopoly functions.

A few years ago, when restructuring, deregulation, and market liberalization were in their infancy, such issues were not widely recognized. The policymakers had naïve, perhaps unreasonable, expectations. It was thought that by the strike of a pen, market discipline would take over all the functions previously performed by regulatory bureaucracies, hence the term deregulation. In reality, it is re-regulation, which often results in more regulations, not less. If the benefits are nebulous and only marginal, then the status quo may be preferable – and certainly less risky.

These are not necessarily views which this author espouses. The experiences of the past few years in California and elsewhere, however, have provided a number of sobering lessons – which any prudent policymaker must now take into account. Competitive markets have their advantages, and tend to self-regulate in the long-run if they are well-designed and well-structured. But there is no consensus, even among the experts, as to what model or market structure is the best. Nor is one solution likely to work in all cases.

Blaming the markets for what has happened in California is unjustified. The profit motive is alive and well, and powerful as ever. It must, however, be properly channeled to do some good. If anything, the main lesson for California is that there is still too much regulations, and not enough competition.

Why Customers Love Rate Stability

In the name of political expediency, the regulators in California in great haste passed a couple of measures to placate the irate customers in San Diego. The legislators sent a bill to Governor Davis to limit electricity prices to 6.5 cents/kWh

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for San Diego residents. This is significantly higher than the average prices for the months of June and July in 1999, which were 2.3 and 2.8 cents/kWh respectively. But considerably lower than the corresponding prices this year, which were 12 and 10.5 cents/kWh, respectively.

The rate caps can be adjusted by the California Public utilities Commission through December 2002, when it expires. What happens after that? That is for future politicians to answer. Nor is it entirely clear if the same would apply to PG&E and SCE customers, once their rate freeze ends. The legislature has also set aside $150 million to subsidize San Diego ratepayers should power costs greatly exceed the new rate cap, but it is not clear what that would be.

Sempra Energy's Chairman, Mr. Steve Baum is not a great fan of the new price cap, and for obvious reasons. The rate cap sets a new limit to how far the prices he charges his customers can rise. But it sets no floor below which they cannot go. Consequently, SDG&E stands to under-collect a significant sum under the wrong circumstances. Nobody said regulators had to be fair, or open minded. Clearly, everyone sees the rate cap as a temporary measure, until more fundamental solutions can be implemented. But as with all regulations, once it is instituted, it will be hard to remove it.

To understand why, all you have to do is take a look at a typical California customer bill in Pacific Gas & Electric (PG&E) or Southern California Edison (SCE) service areas. During the summer, these two investor-owned utilities have been collecting negative competition transition charges or CTC. Under the California's restructuring law, when the average monthly PX prices are high, the CTC shrinks to produce the mandated 10% customer bill reduction.

Figure 7

When the PX Price is High, the CTC Goes Negative

Sample California residential bill for the month of August 2000

ACCOUNT DETAIL

Service	Service Type Bundled Service From 07/31/00 To 08/29/00		Billing Days: 32
Total Charges			$87.44
Legislated 10% Reduction			8.74-
Net Charges			$78.70

Please see definitions on Page 2 of the bill

Electric Energy Charge	$0.19360/Kwh*	$137.26
Transmission**		6.05
Distribution		26.48
Public Purpose Programs		2.21
Nuclear Decommissioning		0.32
Competition Transition Charge (CTC		101.90-
Trust Transfer Amount (TTA)		8.28

** This rate is based on the weighted average costs for purchases through the Power Exchange. This service is subject to competition. You may purchase electricity from another supplier (Call 1-800-743-0040 for a supplier list.)*

***Transmission charges on your bill now include an allocation for Reliability Services (RS) costs. These costs were previously included in CTC and do not increase your total charges. Transmission and RS costs are defined on page 2.*

Note: All customers pay a Competition Transition Charge as part of the charge above, including those who choose an electricity supplier other than PG&E.

Source: PG&E

For the month of August, for example, the average PX price for energy was 19.36 cents/kWh, the highest it has been since the California market opened to competition in March of 1998. As shown in the sample bill in Figure 7 at this price, the customer's energy bill alone would have been $137.26, without the other charges. The only way to keep the monthly bill at the level mandated by the law is to charge a *negative* $101.90 for the CTC.

Multiplied by millions of residential customers, the numbers add up quickly. PG&E, for example, reckons it has collected $2.2 billion less from its customers this summer than it paid to buy power for them from the PX. The same applies to the SCE in the South, although the numbers are not identical.

San Diego Gas & Electric (SDG&E), of course, no longer collects any CTC, and is not subject to a rate freeze, except for the one that has just been introduced (see later comment). No wonder the two incumbent utility distribution companies don't like the rate freeze. Customers, on the other hand, love them, since it provides a free subsidy – when prices are extremely high.

It wasn't supposed to be this way. As stipulated by AB 1890, the rates were frozen at a level that were believed to be high, subject to an automatic 10% bill reduction for all small residential customers. The Investor Owned Utilities (IOUs) were allowed to use the expected extra proceeds to pay off their stranded costs, at which point the rate freeze would end. This is what happened in the case of SDG&E last year – which explains why the customers had no safety net to protect them against the abnormally high PX prices this summer.

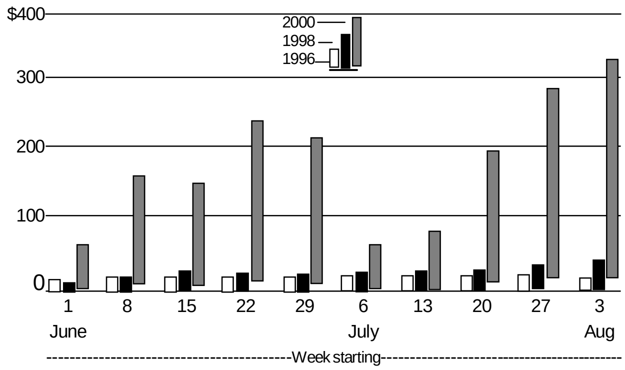
AB 1890 says that if the stranded costs are not fully collected by end of March 2002, the utilities lose out on the balance. At the time of its passage, everybody thought this was a highly unlikely scenario. The widely held view was that all three IOUs would collect all, or virtually all, of their stranded costs long before the deadline. All went well for the first couple of years. In 1998, for example, the average PX price for the period from March through December was $26/MWh. The corresponding number for 1999 was $31. PG&E was charging customers, on the average, $54/MWh – paying off its stranded costs at a rapid rate. SCE was not complaining either. Nobody knew the PX prices would shoot through the roof in 2000, forcing the CTC to go negative for months.

Now the prospects appear gloomy for PG&E and SCE. If the PX prices remain high between now and the end of the deadline, the shareholders of both companies potentially stand to lose a good chunk of change. Not surprisingly, the two companies are quietly lobbying to end the rate freeze. But at the time when irate SDG&E customers are asking for rate relief and a return to stable prices, it is hard to find much sympathy for the plea.

California's Problems Not Limited to California

The scale of the problem extends well beyond California, since eleven Western states, as well as British Columbia and Mexico, are interconnected. California, which has gotten used to buying cheap power from neighboring states, in effect sets the wholesale prices in the entire region now, regardless of whether a given state has deregulated its retail market or not. As shown in Figure 8 wholesale prices during peak demand periods in the Pacific Northwest have been hovering around $300/MWh in July and August as opposed to $30 in previous years.

Figure 8
Prices are High and not Just in California
Average Weekly Prices During Peak Demand Periods in Pacific Northwest,
June-Aug 1996, 98, and 2000; in $/MWh



Source: Northwest Power Planning Council (NPPC)

With so many inquiries under way, a lot more will be said about what happened and why. But it is tempting to ask why SDG&E did not see the storm coming, and if it did, why did it not take protective measures.

How Did SDG&E Miss the Coming Storm?

Rightly or not, the management of SDG&E has been under considerable fire for its mishandling of the crisis. They believe that the criticism is undeserved. After all, SDG&E did not create, nor benefit from the recent price hikes. SDG&E has sold off virtually all its generation assets and only holds a 20% stake in the San Onofre Nuclear plant, which is majority owned and operated by SCE. The company is a mere *price taker*, buying power on behalf of its customers from the PX, as required by the law, and reselling it at zero margin to its customers. Moreover, San Diego's relatively mild climate means that its customers do not contribute much to California's peak demand on hot summer days.

SDG&E management says the company is an innocent bystander in a flawed market gone mad. SDG&E would like its angry customers to direct their frustrations towards *others* including,

- the policymakers who should have devised better market rules to start with, or changed the rules before the recent crisis;
- the lax monitoring and enforcement agencies who should have cried foul once the PX prices began to swing out of control; and
- the greedy generators who took advantage of the tight supplies and lax market rules to make huge profits.

In fairness, there is plenty of blame to go around. But the central question remains why did SDG&E not see the storm coming, and if it did, why did it not do more to reduce the damage by protecting, or at least warning its customers. There are several reasons for this.

- First, SDG&E, like most everyone else, was caught off guard by how precarious the supply situation was going to get and how high prices were going to go.

Despite dire warnings from the California Independent System Operator nobody, it seems, was ready for the inevitable. With triple digit temperatures (in Fahrenheit, that is) in June and July, the ISO had to scramble to fill in as much as a 3,000 MW shortfall in generation capacity on a daily basis. As a result, California energy costs in the month of June alone exceeded $3.6 billion. The total energy costs for all of 1999, by comparison, were approximately $7 billion.

- Second, under California's peculiar market rules, Cal ISO is obligated, and willing, to pay any price to keep the lights on.

The independent, non-profit ISO has a highly focused duty (and desire) to maintain system reliability *at all cost*. Generators have learned that they can make a lot more money by withholding their units from the PX's day ahead *energy market* by bidding scarce reserves in the ISO's *ancillary services market* instead. With capacity in short supply in both California and in neighboring states, every day has been a struggle for the ISO to maintain minimum reserves. Under such conditions, the generators can name their price and get away with it. It is perfectly legal, as far as we can tell.

As obscene as the recent prices may appear, generators simply did what any profit maximizing firm would do, namely, maximize profits. In fact, no private generator can be expected to do otherwise. There are no indications of illegal collusion or price fixing. They may be called greedy, but greed is not illegal.

Legal or not, the consequence has been a dramatic bill for so-called *reliability services*. During a 10 day hot spell in June, ISO paid $387 million for reliability services; the comparable number for *all* of 1999 was $384 million. These costs, along with high energy costs, show up on customers' bills. The net result? Average energy prices in the 13-20 cents/kWh this summer – just for energy. Adding distribution, transmission, and other costs, makes the total exceeds 20 cents/kWh. Even for a high cost state like California, this is too high to bear.

As shown in Figure 7, for the past several months, PG&E and SCE customers have been getting bills with bloated energy charges and hugely negative CTCs. With the rate freeze and the legislatively mandated 10% bill reduction still in effect, PG&E and SCE customers' bills did not go up significantly. The cushioning effect of the negative CTC helps. But for the unfortunate SDG&E customers, there is no rate freeze, no 10% bill reduction, and no negative CTC.

- Third, mixed signals and mishandling of procedural matters led to missed opportunities to secure fixed prices.

As a regulated utility, SDG&E is not free to do what it believes is right for its customers. It must either get prior permission from the California Public Utilities Commission (CPUC), or it can second guess what the regulators may say after the fact. The latter option is risky. For example, suppose SDG&E had locked in early in the spring prices for its customers at 5.5 cents/kWh (which Enron Corp was apparently willing to offer on a long term basis). Now suppose the summer turned out to be a mild one (as in 1999) and the PX prices averaged 4 cents/kWh over the summer. Guess what the CPUC and the consumer advocates would be saying about the wisdom of SDG&E management's decision? Guess who would be eating the difference between the average PX price and the contracted price after a noisy inquiry?

(continued on page 12)

California's Flawed Market *(continued from page 11)*

With these regulatory realities in mind, earlier this year, SDG&E management sought CPUC's blessing before buying price insurance or hedging its risks by locking fixed price contracts in the PX's block forward market. For reasons that are not entirely clear, this critical procedural matter requiring the approval of the CPUC was fumbled. In hindsight, both sides deserve blame in not sorting things out before the summer's crisis hit.

This left SDG&E management in an awkward situation of not knowing whether, nor how, to seek price protection for its customers. This regulatory uncertainty, SDG&E claims, prevented them from buying price insurance prior to the recent episode. Even now, the company is unsure how much risk it can, or should, assume on behalf of its customers in hedging the risk of future price fluctuations. It is a sorry state of affairs, but that's how things currently are in the Golden State.

This illustrates one of the fundamental dilemmas of a market which is neither fully regulated nor fully competitive. The wholesale market is competitive, but once prices get too high, price caps are instituted. The retail markets are anything but competitive, which means that the incumbent utility distribution companies (UDCs) pass on the wholesale prices to customers as required by law. They obviously don't have enough of an incentive to protect their customers from price fluctuations, nor a clear authority to do so.

- Finally—and most importantly—prices, which normally regulate demand in competitive markets, currently have no opportunity to do so even when prices soar.

This means that the great majority of customers have no opportunity, nor any incentives, to curtail demand when prices are high and it is economically efficient to do so. As elementary economics predicts, when demand is fully *inelastic*, there is no response in demand even when prices soar. For the past few months, prices have been soaring, particularly prior to the reductions in the caps from $750, to $500, and subsequently to $250, with no effect on demand. Until this most fundamental flaw of the market is addressed, there is no real hope of fixing the problem, no matter what the politicians say or do.

Where Do We Go From Here?

The fundamental problems of California market are not likely to be easily solved – certainly not through mandated price caps or other artificial constraints. Late in October, the California ISO voted a new variable price cap. The Federal Energy regulatory Commission (FERC) is expected to release a major report on the subject – including a number of recommendations, in early November. This is a market that will be in turmoil for some time before solutions to the problems can be found.

In the mean time, regulators and policy makers in other parts of the world should take notice of what went wrong here, and why. If nothing else, California's mistakes can provide many useful lessons for others who are wise enough to learn from it.

Editor's Note: This paper is based on several articles which originally appeared in the September and October 2000 issues of *EEnergy Informer*.

IAEE Meeting At the Annual ASSA/AEA Conference

The International Association for Energy Economics will be having its 3rd Annual Session at the Allied Social Science Association in New Orleans, Louisiana, USA January 5 - 7, 2001. If you attend the ASSA meeting please register as a member of IAEE. With more members attending we will be able to increase the number of sessions. We hope to see you there.

Session Title:

Current Issues in Energy Economics and Energy Modeling (Q4)

Presiding: *Carol Dahl*, Colorado School of Mines

Boris Cournede, Ministry of Economy, Finance, and Industry, Paris, France—The Special Economics of Gas Deregulation on the European Continent.

Prakash Loungani, International Monetary Fund—21st Century Oil Shocks: Will They Occur? Will They Matter? Will We Be Prepared?

Prasad Rao, The Pennsylvania State University—The Choice of Crude Oil Quality in Petroleum Refining

Anne Epaulard and *Stephane Gallon*, Ecole Nationale de la Statistique et de l'Administration Economique, Malakoff, France and Ministry of Economics, Finance and Industry, Paris, France—A Model of Competition Between Nuclear and Gas-Fired Plants Using Real Options Theory to Assess Nuclear Investment Value

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