“The Perfect Mess”
How California’s Energy Markets Sank

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“The Perfect Mess”: How California’s Energy Markets Sank

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Abstract

California's current energy crisis is rooted in over a quarter-century of policy decisions. Restructuring was the third failed attempt at reforming the state's electric utility industry, with each of those failures setting the stage for the next attempted reform. Federal policy has had an important role in both encouraging these reforms and in stymieing their success. The bust-to-boom state economy in the 1990s obscured many of the hazards in restructuring. A lack of trust among the utilities, regulators and customer groups blocked opportunities to resolve key issues. Ultimately, prices exploded due to a combination of many factors in a "perfect mess." Important lessons from California’s restructuring experience go beyond the usual adages about market design into the political economy and institutional settings that lead to disaster.

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Introduction

A wide range of opinions has been expressed as to why California suffered through an energy crisis of unprecedented magnitude, starting in May 2000. Some claim that setting up a market was inappropriate for managing electricity. Others say that too many regulations were left in place, and market forces were not allowed to operate properly. Yet others point to rapidly rising demand and fuel prices as the main explanation. But a closer examination finds that the answer is much more complex than the casual observed might think.

Apparently unbeknownst to many, the voyage to this disaster has been long and arduous. As in the "Perfect Storm," a confluence of policy and corporate decisions, economic trends and even the weather has created the "perfect mess." Over the last 25 years, California steered an erratic course, first swinging the helm one way and then the other to respond to shortages and surpluses. In the end, the ship of state has foundered on the rocks of procrastination and hubris.

The original "energy crisis": 1973-1985

The roots of the current crisis extend back to the original 1973 energy crisis created by the Arab oil embargo. Gasoline prices tripled by the end of the decade, and other energy prices rose commensurately. Both the federal and California governments started programs and regulations that still affect energy policy today. The California Energy Commission (CEC) was created in 1974 to develop statewide energy plans, and to review whether new electricity generation plants were "needed"—the first time the state ever took that step (California State Legislature 1974).

The influence of that first crisis on economic trends was equally profound. Utility companies discovered that producing electricity was not going to get cheaper endlessly, and that consumers reduced consumption when prices rose. Given that utilities traditionally made more money on every additional kilowatt-hour they sold, this threatened the core of their business strategies.

These two profound shifts collided in California in the late 1970s during the application for a permit from the CEC for the last nuclear plant proposed in this state, San Diego Gas and Electric‘s Sundesert Nuclear Generating Station (San Diego Gas and Electric Company 1978). The CEC staff used its new demand forecasting methods to show that California did not need the Sundesert plant. SDG&E, under pressure from numerous parties, including the neighboring larger utility, Southern California Edison, eventually withdrew its proposal. In fact, the utilities viewed the new siting process as so arduous that they never again proposed to build a large new power plant to be owned within a regulated company, even as the energy crisis continued into the 1980s. (More on *unregulated* ownership later).

Deregulation—round one: 1978 to 1988

Meanwhile, the Federal government went on a deregulation tear in 1978. Industries that had been closely regulated for decades—railroads, trucking, airlines, and natural gas production—were set free of price controls. As part of that trend, Congress enacted the Public Utilities Regulatory Policy Act of 1978 (PURPA). PURPA encouraged states to allow electricity generation to be owned by non-utility companies, such as oil refineres and lumber mills. This policy intended to improve energy efficiency through use of cogeneration—the simultaneous production of power and heat--and renewable resources.

California, ever the trendsetter, embraced these principles like no other state. In 1982 and 1983, now looking at a potential shortfall, the California Public Utilities Commission (CPUC) required the state's investor-owned utilities (IOUs) to sign "standard offer" contracts with any "qualifying facilities" (QFs) that met the federal criteria under PURPA (California Public Utilities Commission 1982). The standard offer payments supposedly were based on the utilities' "avoided costs"—how much it would cost a utility to build and run an equivalent power plant.

Unfortunately, the CPUC made two mistakes in establishing the payment terms. The first was a conceptual error that led to, in some cases, almost doubling annual fixed payment to certain QFs. The second was to peg the energy payment for renewable resources (i.e., solar, wind, hydro and biomass) to an oil price forecast that predicted $100 per barrel by 2000 (California Public Utilities Commission 1983). Eventually these mistakes led to paying renewables up to six times the true value of their energy.

QF power developers quickly recognized how lucrative these contracts were, and proposed thousands of megawatts[i] of new plants. The CPUC wavered about whether too many QFs had signed up. Developers used the delay to take part in a new "gold rush" in the last few weeks before each standard offer was withdrawn (California Public Utilities Commission 1985). Southern California Edison Company set up an unregulated subsidiary, Mission Energy, to partner in many of the larger projects to also take advantage of this opportunity. In the end, over 11,000 megawatts of QFs—almost a third of the state's generation--were built and paid for at these extraordinary prices. Most of these plants are still operating today, and paying for their energy has been one component of the current crisis.

At the same time, Pacific Gas and Electric Company was muddling through the construction of the last nuclear power plant built on the West Coast, Diablo Canyon. Through a series of misjudgments and mistakes (including reversing the blueprints for one unit), PG&E managed to surpass the original cost estimate by ten-fold to over $6 billion. The state decided that PG&E should take some of the risk of recovering those costs, rather than simply passing them directly on to ratepayers. A consultant advising the state believed that PG&E never would get the plant to run properly. Based on that advice, in 1988 the state offered PG&E an agreement based on a QF standard offer (1988). However given the strong economic incentive in that agreement, Diablo Canyon has generated 30% more energy than the average output for a U.S. nuclear plant—well beyond the state's expectation. The payment to PG&E was about three times the value of its energy until the recent market price spike. PG&E has now recovered about $8 billion of its $6 billion investment, having fully recovered its investment by January 1998.[ii] This debacle was the final nail in the coffin of regulated generation in California.

The age of surpluses: 1986-1998

Costly generation translated into higher rates. Growth in electricity demand slowed, just as the CEC had forecasted in the 1970s. California's economy probably could have simply absorbed the higher electricity rates, albeit with increased conservation, if industrial customers had not become extremely sensitive to energy prices during this

[i] One megawatt equals 1,000 kilowatts. The typical home uses an average of about 500 kilowatts per hour.

[ii] Based on the author's calculation using CEC and CPUC data.

period due to two events.

The first event that increases this sensitivity was the emergence of the "gas bubble"—an oversupply of natural gas in North America--in the mid-1980s created by deregulation of the industry. Several federal rulings allowed any one to use interstate pipelines to ship cheap gas (1992; 1985). As a result, natural gas became a prime fuel for generating electricity. An industrial customer now could build a new power plant and run it for less than half the cost of a utility's nuclear plant. Utilities faced the prospect of losing industrial customers, which would lead to higher rates for their other customers.

The second event was the 1990 recession, which hit California particularly hard. The state did not emerge from the recession until several years after the rest of the nation. Electricity demand actually fell in Southern California between 1991 and 1995 (California Energy Commission 2002). As a result, the state looked like it would have a tremendous surplus of energy for at least the next decade. This apparent surplus was accentuated by an overoptimistic assessment of how much conservation would occur during that time (Dale 2001). That overestimate was rooted in a misplaced belief in the effectiveness of government-mandated, utility-managed conservation programs.

The state still realized that it needed to have a process in place to acquire new generation in the future when new resources would be needed and to encourage renewable resource development. Instead of issuing standard offers again, generation developers were asked to bid against proposed plants that might be built by the utilities (California Public Utilities Commission 1988).[i] The bidding process was heavily weighted toward renewable resources as a means of encouraging environmentally-friendly development. Eventually bids were awarded for about 1,400 megawatts, or about 1% of the state's total (California Public Utilities Commission 1988). But the utilities successfully argued to the Federal Energy Regulatory Commission (FERC) that California did not need new generation until 2005. FERC overruled the state awards in 1995, more than six years after the start of the process.[ii]

This setback forced the state back to the drawing board. With restructuring already

[i] Known as an "identified deferrable resource" or IDR.

[ii] FERC issued its initial decision in 1992, and the final appeal was denied in 1995.

proposed in 1994 and an apparent generation surplus, the CPUC decided to wait rather than fix the process then (California Public Utilities Commission 1994). However, the creation of a deregulated market that could sustain new generation waited until 1998. In the end, the delay in proposing new generation added up to a decade. Little of this slippage arose from environmental regulations; it was much more the result of "changing policy horses in midstream."

Deregulation—round 2 "Restructuring as the "solution": 1994 to 1997

So restructuring was negotiated in 1995 and 1996 with a backdrop of a lingering recession that depressed energy demand, an apparent excess of generating capacity, an overhang of expensive power contracts, abundant and cheap natural gas supplies, and an increasing push from the federal government to open up electricity markets. The utilities, regulators and legislators cut a deal to start deregulation, while supposedly creating a "win-win" situation in Assembly Bill 1890 (1996). Customers would get to choose their power providers. In return, the utilities would deliver power at a relatively high guaranteed fixed retail price from January 1998 to March 2002—the "transition" period to competition--but the utilities would be able to keep the difference between this guaranteed rate and the lower actual cost of wholesale power to pay off their "stranded investments." Stranded investments are the costs of power plants that would not be recovered if the utilities were forced to charge a market-based rate, rather than being allowed to recover their full, higher costs directly in rates.

The utilities (and the regulators) made a bet that the power surplus would last through 2002. At the time, the utilities owned most of the generation so that this did not seem so risky to most everyone. With such a surplus, the short-term market price would stay well below the fixed retail rate negotiated with the regulators. This would increase the probability that the utilities would fully recover their stranded investments. To "lock in" low prices during the transition period, the utilities pushed for all power to be bought and sold through a day-ahead or "spot" market called the Power Exchange. The utilities were so sure that the surplus would last that they agreed to Public Utilities Code Section 368(a). This section states:

The electrical corporation shall be at risk for those costs not recovered during that [transition] time period.

Essentially, the utilities took on the full risk of supplying power at the "frozen" rate during the "competition transition period." The underlying problem today is that the utilities failed to hedge their bet. (More on this later.)

Under restructuring, PG&E and SCE were encouraged to sell off half of their fossil-fueled generation to mitigate the potential exercise of market power in generation prices.[i] The plants, the newest built in 1972, were expected to fetch less than the remaining investment carried on the utilities' books. Much to everyone's surprise, almost all sold for well above "book" value. The first auction encouraged PG&E, SCE and San Diego Gas and Electric Company to sell the rest of their generation. (All three utilities sold all of their significant gas-fired generation. Legislation in response to the electricity crisis stopped the sale of PG&E's hydro, and SCE's hydro and coal plants in 2001.) The surprising auction results were a hint of what was to come. Apparently, the new owners were either foolish or recognized an opportunity that escaped everyone else.

Rough sailing during the "transition": 1998-2000

The restructured marketplace opened three months behind schedule in April 1998. In the midst of the second wettest year on record on the West Coast, market prices often hit zero (and were even negative in some ancillary-services markets[ii]) due to the abundance of hydropower through June 1998. Then suddenly prices took off. A bid of $9.99 per kilowatt-hour set the market price one hour in July 1998 and would have been higher except for a computer input error.[i] The high prices and market volatility caught the market regulators and the utilities unaware. Prices seemingly could be driven to the sky in certain situations. Bids were capped as 75 cents per kilowatt-hour as a quick fix. A seesaw of chaotic market redesign ensued that has continued to this day.

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[i] AB 1890 makes no mention of divestiture. The CPUC adopted a set of incentives to encourage the two largest utilities to divest half of their fossil-fueled generation. These gas and coal plants represented about a third of PG&E's and half of SCE's total generation. (See [California Public Utilities Commission, 1995 #317])

[ii] "Ancillary services" are needed to keep the system stable and reliable, so lights will not flicker and to backup power sources that might be lost suddenly.

Underlying the unexpected market activity was a number of interrelated issues. Parties positions on these issues generally reflected each of theirs primary objectives: for commercial and industrial customers and alternative providers, it was to hasten the beginning of “true” competition; for utilities, it was to protect their competitive advantage as long as possible; and for residential customers, it was to prevent large customers and utility shareholders from leaving them with the unrecovered costs. How each of these groups played out their strategies ultimately intensified the coming crisis and erected roadblocks to its solution.

The residential ratepayer groups struck first by placing Proposition 9 on the November 1998 ballot to rescind the stranded-cost recovery portions of the restructuring law. However, proponents were outspent 30 to one, and it was never viewed as a serious threat to restructuring.

The utilities, particularly PG&E, recognized early on that it was too their advantage to delay the end of the transition period to the last possible moment. Rates were frozen during that period, which would end no later than March 31, 2002, and potential competitors found that it was almost impossible to peel off customers under the transition conditions—they simply could not offer large enough discounts. Enron quickly decided to drop out of the residential market entirely, and only “green” marketers ever made significant inroads into that market segment. The transition period could have ended earlier if “stranded” utility investments, that is plants that cost more than the market-going price, were fully recovered. PG&E pursued a conscious policy, as noted in a 2000 CPUC decision, to extend the transition period as long as possible to protect its market share (2000).

The residual stranded asset charge gave the utilities the incentive to depress wholesale market prices initially through oligopsony. Depressing the "competitive" market price would increase the amount of stranded costs recovered during that period by depressing the true market value of the resources. Then after the end of the transition period, the utilities could let the market price rise to its true level. Because the valuation used to establish the stranded asset charge did not reflect the true market value of these assets in

[i] Average electricity rates are less than 15 cents per kilowatt-hour.

the future, the utilities would have essentially double-collected on the market rents for the generation assets they continued to own.

A second utility strategy was to deny energy service providers (ESPs) the ability to recover adequate metering and billing costs. The utilities were charging ESPs several times higher than what the utilities credited to the ESPs for directly providing the same services to the ESPs own customers (Marcus 2000). This disparity erected further barriers to effective retail competition.

Industrial customers and ESPs pressured the utilities to take actions to end the transition period earlier so that they could get out from under the transition charges. One aspect of that strategy was to oppose long-term contracting authority for the utilities until the transition was over. SCE initially applied for this authority in the spring of 1999, and the utilities pushed harder until the CPUC adopted a policy opening up long-term contracting. However, the State Legislature, at the behest of various ratepayer groups immediately vacated this decision in the state budget adopted in July 2000.[i]

The utilities did not help their cause on long-term contracting by continually refusing to pursue long-term contracts unless they were freed from CPUC review of those contracts. The utilities argued that they could be left exposed if the CPUC rejected those contracts, but the CPUC and others recognized that the utilities could manipulate those contracts to extend the transition period and enhance their competitive advantage. This tension eventually exploded with the market in the summer of 2000.

Ultimately, the utilities failed to pursue any risk-hedging strategies. Their ability to sign long-term contracts was limited for various reasons, but they did not take advantage of the opportunities that they had. Another option would have been to encourage more retail competition, so that they would not be responsible for so much of the power purchasing requirements. A third strategy would have been to implement more energy efficiency and load management programs, so that the utilities could reduce loads if prices spiked. The utilities also could have held on to a portion of their "peaking"

[i] Public Utilities Code Section 355.1 required the investor-owned utilities to continue to buy all of their power through the Power Exchange and Independent System Operator. Neither market had an adequately functioning forwards or futures market. Section 355.1 was repealed in January 2001 in Assembly Bill 1X (Keely).

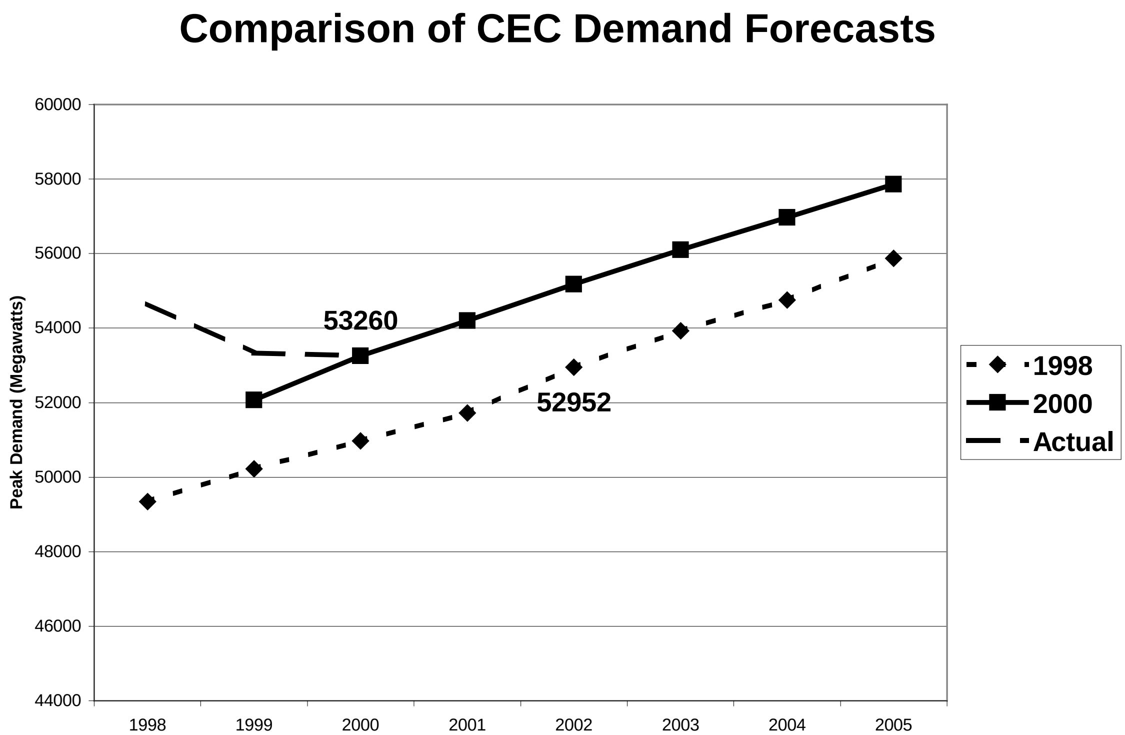
resources rather than selling them. This would have allowed the utilities to better control market prices during the highest-priced peak periods. Despite overlooking all of these opportunities, the utilities did not even take the most fundamental and prudent step of conserving their cash for a "rainy day." PG&E and SCE each collected as much as $5 billion and $2 billion, respectively, above direct costs by May 2000, but rather than conserving cash, they transferred all of it to shareholders or acquisitions (McCann 2001). Failure to adopt any hedging strategies led to the financial crisis.

The most serious aspect of this transition period was the erosion of what little trust existed among the utilities, customer, regulators, and the Legislature. Ultimately, this lack of trust prevented the adoption of preventive actions, and slowed responses to the crisis.

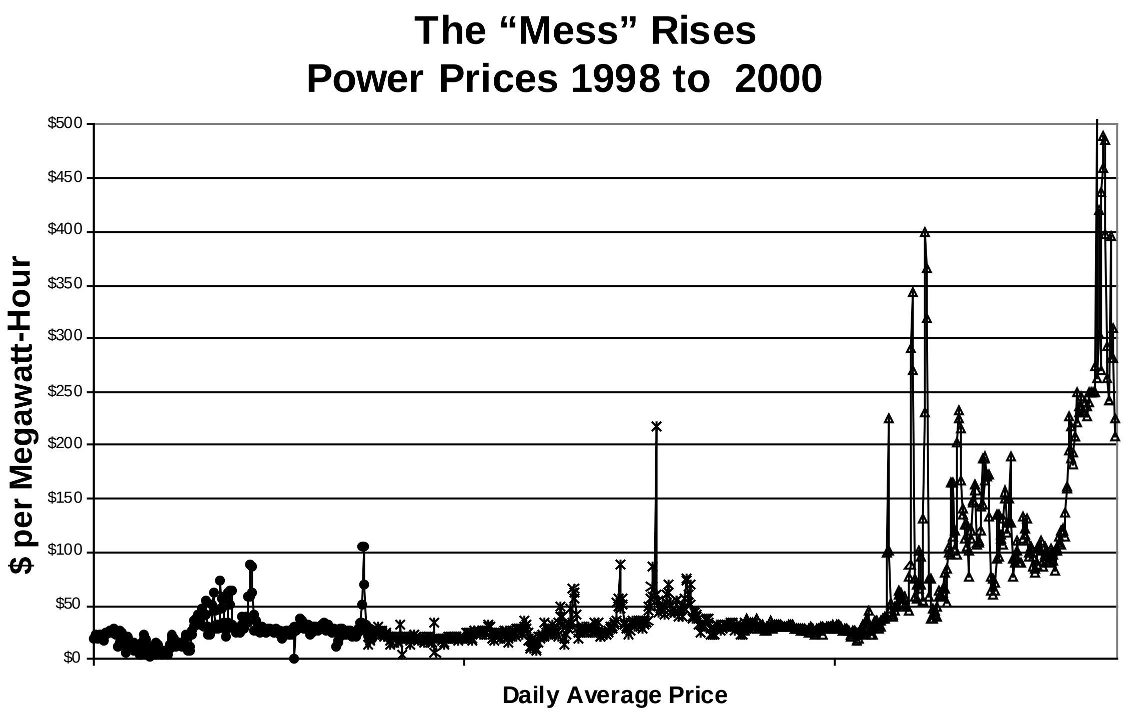
The storm descends--the second energy crisis: May 2000 to May 2001

Despite these unexpected events, the average market price hovered in the range initially predicted by restructuring proponents through mid-May 2000. SDG&E paid off its stranded investments in May 1999, and its ratepayers enjoyed a rate reduction. However, some observers expressed skepticism about the ability of such low prices to sustain the necessary investment in new generation. Little did they know all of the forces were about to converge in the "perfect mess."

The U.S. economy rolled through a record period of growth in the spring of 2000. Much of that growth was concentrated in the West, which is the center of the world's technology economy. Region-wide expansion reportedly topped 8% from mid 1999 to mid 2000 (VanVactor 2000). The result was unexpected increases in energy demand, with most of it <u>outside</u> California. Even so, California's own demand accelerated, reaching 53,000 peak megawatts two years earlier than forecasted in 1998 by the CEC, as shown below. This regional spurt came just as hydropower availability in the Northwest fell from the above average conditions of the previous five years. But the low prices for electricity and natural gas had suppressed a commensurate expansion in supply. In fact, the rest of the Western states had been as remiss as California in constructing new plants. Unfortunately for California, the other states simply reduced their exports to California, thus compounding the intensity of power shortages in the state.



First natural gas prices doubled from January to April, and then an unseasonable May heat wave blew the top off the Western electricity market. Generators apparently discovered they could ask any price during virtually any hour of the day. Prices rose ten-fold overnight from 3 cents per kilowatt-hour to 30 cents, as shown below (University of California Energy Institute 2001). The Independent System Operator responded by reducing the maximum price that it would pay for power to 50 cents per kilowatt-hour, then to 25 cents in an attempt to control prices. The Southern California air emission permit market picked up the price spikes in June, rising more than twenty-fold by August. The high permit prices reinforced the high electricity prices, and these added charges probably cost state ratepayers $2 billion (Moore 2000). The El Paso natural gas pipeline suffered a major explosion in August, which reduced gas delivery capacity to Southern California just as it was needed most (O'Donnell 2000).



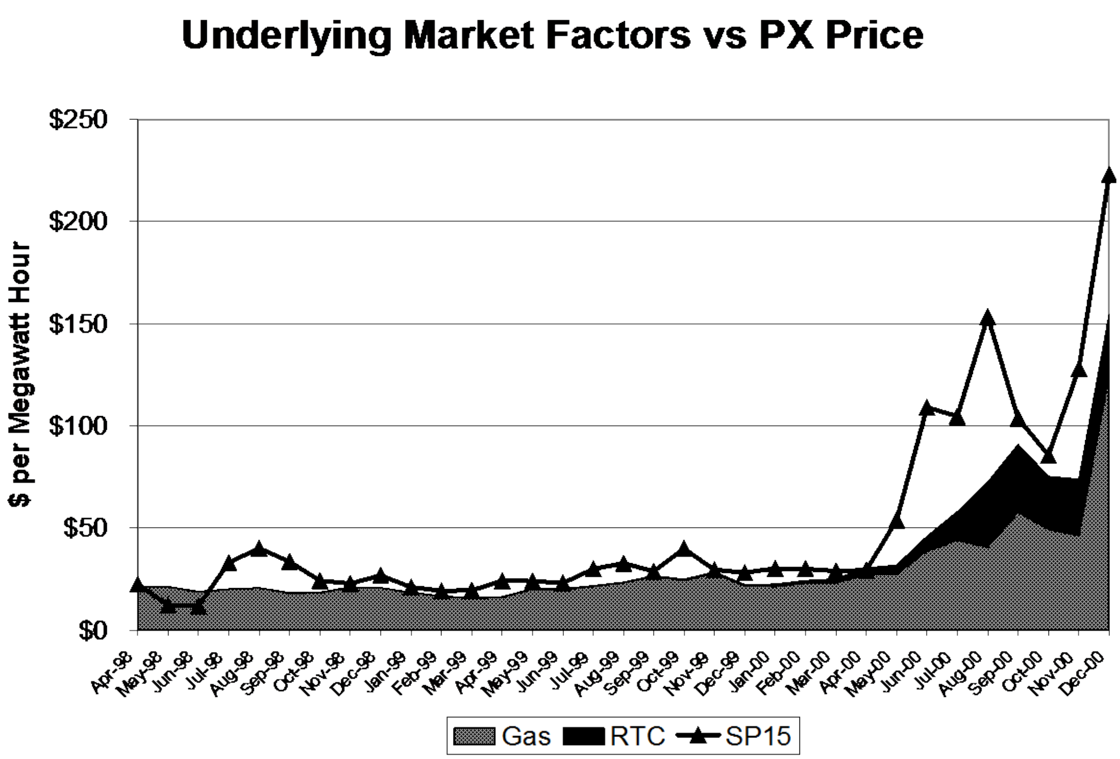
SDG&E customers were the first to suffer because their retail rates were no longer "frozen" as was the case with PG&E and SCE customers. Their rates doubled from June to July. The outcry forced the Legislature to cap SDG&E rates, and set up a mechanism to recover the excess costs starting 2003 (2000). Unfortunately, the Legislature's action probably led PG&E and SCE to believe that they also would be bailed out at a later date.

Just as the market looked like it might start to settle down, a cold wave hit the western U.S. in mid-November. A subsidiary of El Paso owned most of the available capacity, and "coincidentally" prices for pipeline capacity into Southern California rose from $8 per thousand cubic feet to over $50 in a space of week (O'Donnell 2000). Electricity prices again went wild. Market prices hovered near the price cap around the clock by late November. The utilities were now spending more to buy power than during the previous summer's crisis.[i] Due to their lack of risk hedging, they were fully exposed and on the brink of bankruptcy.

Throughout all of this, the new "merchant" generation plant owners, such as Duke,

[i] About 40% of the purchased power came from generation resources that they either owned. This meant that much of the money the utilities owed was to themselves.

Reliant, Mirant, Dynegy, AES, and Williams, were accused of manipulating power prices. While these plant owners could point to high natural gas and emission permit prices (and there are questions about whether these markets were manipulated as well), power prices still appeared to be at least double the underlying costs of power production, as shown below. Whether through collusion or not, it appeared that generators had found how to influence market prices without fear of losing market share. Whether this violates the Sherman Anti-Trust Act or the Federal Power Act is at the heart of the current dispute at FERC.



FERC finally initiated an investigation in August, but its final order in December imposed a so-called "soft" price cap of 15 cents per kilowatt-hour, which never actually was effectively implemented by the California agencies (2000). FERC also allowed the utilities to avoid selling their own generation and contracts into the Power Exchange, thus potentially saving 30% off purchased power costs. Without these "self pass-through" sales to cover its high operating costs however, the Power Exchange was doomed, and it closed down in February. In 2001, FERC has issued orders for minor refunds by power generators, and another quasi-price cap order with numerous conditions. Otherwise, FERC stood on the sidelines throughout the winter and spring of 2001.

Finally, with no real relief coming from the federal government, the state stepped into take over power purchasing on January 17 (Davis 2000). The State Legislature authorized the continuation of short-term purchases and the acquisition of long-term power contracts in Assembly Bill 1X signed January 31. Californians all became public power customers at that moment. About one-third of the state's power comes from generation still owned by the utilities—most hydro, nuclear and coal. Another third comes from the costly QF generators. The remainder now is purchased by the state Department of Water Resources (DWR), and is directly billed to consumers. Contracts buying power have been signed for most if not all of the state's power needs for the next 10 years (Navigant Consulting and Montague DeRose 2001).

Muddling through in 2001

The crisis actually was two crises. The first was financial, as to how costs will be recovered and the utilities made solvent. The second was an actual physical shortage of generating capacity that became evident in May 2000. The rolling blackouts during the relatively low-demand winter and spring periods were the result of the financial crisis, as generators withheld power. The blackouts forecasted in the summer of 2001 reflected an expected continuation of the physical crisis. A forecast by the National Electricity Reliability Council called for up to 260 hours of rolling blackouts (North American Electric Reliability Council 2001). Demand rises 50% over wintertime levels due to air conditioning loads. However, available generation increases only a small amount. The state managed to stem the physical crisis however, and is now left with how to pay for this mess.

The state government was slow to respond to the physical crisis, and the federal government seemed to believe that massive new generation could be thrown up overnight. The state finally moved to a crash building program and waived many environmental regulatory obstacles. Many of those waivers remain place today despite the apparent end for their need.

Fortunately, the state skated through the summer of 2001 through a combination of factors. Primarily, consumers cut usage by 5 to 10 percent starting in January (California Energy Commission 2002). Their response echoed the reduction in water demand during the early 1990s drought—most of it was the sum of simple uncoordinated individual actions. A relatively cool summer, with heat spells well timed to coincide with holidays, helped as well. On the supply side, DWR had bought substantial power for the summer, taking pressure off the spot market. FERC finally imposed effective price caps June 19, which took further steam out of the market (2001). And the political heat on the unregulated generators forced them to reduce their plant outage rate back to historic levels, which were one-third the rates experienced the previous summer.

In response to the financial crisis, the two utilities chose two different paths for resolution. In early April, PG&E declared Chapter 11 bankruptcy—the largest ever by an energy utility (2001). The Governor then hastily signed an agreement with SCE to purchase its transmission lines, and to allow SCE to recover much of its past expenditures (2001; 2001). PG&E is pursuing legal remedies in the belief that a judge is more likely to give it a fair ruling. SCE is using political means in the theory that it can better control the outcome.

DWR signed enough long-term contracts so that 85 to 99 percent of California's power needs are covered through 2010. Unfortunately, the state appears to have "bought high, sold low," and a substantial portion of the $43 billion in commitments will likely be another set of "stranded costs."

The State Legislature, the CPUC, the FERC, and the Bankruptcy Court are all considering how to recover both past and future costs in rates. Whether and how the utilities might recoup their purchased power costs before January 17 is at the core of both these hearings and the negotiations over the transmission system purchases. These decisions largely will turn on a single question: Did the utilities agree to guarantee to deliver power at a frozen rate in exchange for the enhanced opportunity to recover their past investments?

What did NOT happen in California

Many commentators have opined on what "went wrong" and how it could have been fixed. However, they often have their facts wrong and fail to understand the political and institutional dynamics that shaped restructuring.

Perhaps the favorite explanation is that retail rates were frozen while wholesale prices fluctuated. First, any sensible person would say that allowing retail prices 30% above actual costs should be sufficient margin. Both PG&E and Edison still had collected more than they had spent from April 1998 to December 2000. The financial crisis was in fact created by the utilities transferring the excess funds to their parent holding companies, PG&E Corp. and Edison International, and then refusing to return those funds when needed. Second, electricity demand in the short run is extremely inelastic, i.e., unresponsive to changes in prices, and consumers would not have reduced demand substantially during the summer of 2000. SDG&E customers faced a doubling in their rates because their rates were no longer frozen, and they reduced demand by only 2 to 6 percent. Allowing retail rates to float with power prices only would have taken pressure off utility shareholders.

A second favorite explanation is that California failed to responsibly build power plants. The fact is that none one would seriously consider building generation during the long recession in the first half of the 1990s, and the uncertainty surrounding the first restructuring effort in the nation lead to more caution by developers. Once restructuring was underway, proposed generation flooded the state. By mid 2000, over 15,000 megawatts was in various stages of construction and permitting in the state (2000; 2000). An associated problem was that the waiting period for a generation turbine set was 18 to 36 months (Savage 2000). In other words, California could not have put up new generation in 2000 or 2001 beyond what was already being built unless it had bought out planned plants in other states.

Finally, these commentators ignore the importance of paying for the utilities' past investments or "stranded costs." The magnitude of these costs dwarfs those of any other state—a common estimate used in 1996 was $28 billion. The "headroom" created by the frozen rates was the mechanism chosen to pay for these costs. Without stranded cost recovery, the state's two most politically-powerful corporations, PG&E and SCE, would have blocked any reform of the industry. Failing to propose a workable solution to this problem undermines the credibility of any other discussions about the California crisis.

A look back at what restructuring wrought

In a perfect world, a centrally-planned cost of service utility system and decentralized competitive market both should deliver electricity at the expected least cost (Blanchard and Fisher 1990, pp. 76-77.). However, the experience with cost of service regulation revealed significant and obvious flaws. Under cost of service regulation, utilities have a strong incentive to overbuild capital-intensive power plants that generate the greatest guaranteed return on investment to its shareholders. The construction of numerous unneeded, expensive nuclear plants is one example of the so-called "Averch-Johnson Effect" (Kahn 1988, pp. 49-59). The assurance of full-cost recovery reduces the incentive for the utility to choose a new, lower cost technology. Such innovation in fact can reduce gross investor returns. Further, cost of service regulation concentrates forecasting and decision making into a few individuals and agencies. This meant that little was done to insure against a range of potential outcomes in the future. An example of this failure to diversify generation portfolio resources is California's Interim Standard Offer 4 Qualifying Facility contracts which paid most renewable energy generators on the assumption that oil prices would rise to $100 per barrel by 2000. The potential errors from the concentration of decision-making are exacerbated by the fact that ratepayers bear virtually the entire burden of those errors. Traditionally, utilities have suffered little in disallowed ratebase from plant cost overruns and other problems. Thus, utilities, and even regulators, have little incentive to hedge against future events. In addition, cost of service regulation introduces an element of political influence and rent seeking into the resource development and price setting process. Influencing regulators, who make decisions for millions of ratepayers, becomes paramount and such cases need not be decided solely their merits, just as in any other governmental rulemaking.

Deregulation and restructuring of previously regulated industries, such as telecommunications, railroads and natural gas, have produced dramatic benefits. However, the competitive markets that underlie these policy initiatives require several attributes to be implemented successfully. Unfortunately, the Western grid markets never developed these characteristics sufficiently.

First, competitive markets require that prices reflect well-informed decision making and be transparent for the product or service being purchased. Too often market rules required confidentiality that benefited one set of participants over another. The sequential, multi-product markets made price comparisons difficult. Second, competitive markets exist only if many sellers are participating and do not control a significant share of the market, or if entry into the market is relatively easy and costless so as to discipline existing sellers. Unfortunately, the California market was dominated by a half dozen generators who controlled virtually all of the price-setting units. Entry was extremely difficult due to a combination of transmission interconnection issues, a two to three year backlog for generator turbine sets, and state and federal environmental requirements for plant certification and construction. Third, buyers in the market must have real choices. The combination of the rate freeze, used to recover stranded assets, and suppression of the retail market greatly constrained those choices. As a result, generators faced a highly inelastic demand, and only competed with a small number of other generators. In addition, the market never matured to the point to offer a diversity of products and services that would have been available with true retail competition. In fact, this ability to reveal the true range of preferences by consumers can be the greatest single benefit of such a market. This diversity can manifest itself in a mix of different contract periods and pricing terms, and can be used to hedge against future risks. Finally, the market must equitably share risks among participants to provide efficient decision-making incentives. Generators must be allowed to suffer losses and even fail, and ratepayers must be allowed to suffer through high prices when true scarcity occurs. The utilities are meant to be only agents in the transactions between generators and ratepayers, but the failure to convey rational price signals and the lack of a true retail market instead put the utilities into the role of the de facto consumer. The California market design became a recipe for disaster due to its failure to meet these requirements for a competitive market.

In the end, the California market was a set of oligopolist generators selling to oligopsonist utilities. The generators opposed wholesale market reforms that would increase market transparency and reveal confidential data while the utilities believed that they could pass all power purchasing risks on to ratepayers. Meanwhile, the utilities opposed retail market reforms that would have provided ratepayers with other options, and attempted to manipulate their costs so as to extend the stranded cost recovery period, and thus raise barriers to entry by competitors.[i] Such a situation is far from a competitive market situation, and in fact, predicting the outcome in such a market with limited participants is difficult (Saleth, Braden, and Erheart 1991).

Warts and all, at least cost of service regulation mitigates against the risks of excessive costs or loss of investment. The failure to establish and maintain the necessary conditions for a workably competitive market leads to a situation where either buyers or sellers can dominate. The result is a socially-inefficient and inequitable outcome. In addition, neither consumers nor sellers gain confidence in such lopsided markets, and any potential efficiency gains are lost due to their aversion to participating and investing in such markets. Cost of service regulation places upper and lower bounds on what consumers may pay, and the return on investment. Such regulation provides a "safety-first" refuge from the ravages of misbehaving markets.

The CDWR contracts could hinder the development of mature competitive markets in the Western U.S. by creating artificial incentives to overbuild generation capacity, some of which may be inefficient technologies, and leading to large power surpluses that suppress development of other resources that do not have CDWR contracts. California's load need increase by only 1% per year rather than the forecasted 2% to lead to this outcome. The state experienced similar sluggish growth from 1988 to 1998 after its last utility reform effort, also compounded by a recession. When the contracts end by 2011, California will have had little experience in using markets to meet its electricity needs. The lesson the state is most likely to learn from the 2000 energy crisis and the subsequent contracting situation is that markets cannot be trusted to deliver potential benefits. The result could be either a highly imbalanced system that is primed for another disaster when the CDWR contracts end, or a return to entirely centrally-planned, and even government-owned, generation resource development.

Useful lessons in California's shipwreck

From California's disaster, we may be able to better identify the necessary ingredients for a successful market transformation. There were a myriad of mistakes; however, most

[i] See CPUC decision on PG&E's General Rate Case, D.00-02-046, p. 85.

could have been addressed with proper cooperation and anticipation by the involved parties. Some important principles are necessary for restructuring to work:

- Successfully moving to a restructured market must result in winners and losers. Pain cannot be avoided--if it can, then one should ask "did anything change?" The politician's favorite "win-win" outcome actually means either nothing has changed or disaster is looming.
- The market must either be transformed quickly to a fully-competitive model by removing any competitive advantages for the incumbent utilities (as was done with telephone long-distance, airlines, trucking and other successful deregulation efforts), or small customers must be completely insulated in the initial steps with utilities remaining responsible for procuring their energy and providing full services. In either case, oversight by a strong "policeman," whether it is Judge Green or the FERC, is a necessary component of a successful transformation. Attempting to straddle market transformation is like having one foot on the dock while the boat is leaving port.
- Power should be purchased largely through longer-term bilateral contracts of varying lengths, with short-term spot markets only filling a small portion of demand. Long-term contract prices will often be higher than "spot" prices because the sellers are accepting more of the risk associated with power generation costs. Short-term markets must be designed to limit "gaming" among the energy and reliability markets.
- When restructuring the electricity market, not only must there be sufficient generation capacity initially (or at least substantial forward contracting of capacity), but also sufficient capacity in fuel supplies and delivery capability, water supplies, and environmental permitting conditions. Only with this cushion is it possible to carry out a successful transition, particularly in what is probably the most complex single industry in the world.
- Utilities' stranded investments costs must be recovered in a manner that does not distort the market price or the incentives for competitors to enter the market. Using

the difference between “frozen” and market rates to recover past investments is a recipe for disaster.

- Third-party providers must be legally and contractually bound either to provide power to their customers or to pay the utility the full costs of purchasing replacement power when customers are returned to default service.
- Conservation and load management should be implemented at full value for customers. Savings should be considered not only in reduced power generation, but also in reduced investment in the delivery grid. To eliminate the conflict of interest from reducing demand, these services should be administered by entities other than the utilities.

Restructuring had promised to navigate California out of the quandary that the state had created over the last quarter-century. Instead Californians find themselves tossed in high seas, waiting to be thrown on the rocks at any moment. Even now, yet more energy policy decisions likely will hound the state for the next quarter century with no rescue in sight.

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