Introduction

Unanticipated demand growth, volatile hydro supplies, dilatory planning, bungling regulation, and political myopia have combined to make a shambles of Western electricity and gas markets. Critics complain that the market is “broken,” and if wholesale prices are the thermometer, clearly the patient is mortally ill. The cost of power has risen steadily since May 2000 and has sustained a level ten times that of comparable prices elsewhere in the U.S. Defaults and the threat of insolvency have combined with beggar-thy-neighbor actions by the region’s politicians and regulators to reduce trade to a fraction of normal. The retreat to autarky and resulting uncoordinated behavior has reduced effective reserve margins, increased cost, and diminished reliability. Power shortages could easily spread throughout the West as summer peaks approach.

The tortured attempt to unwind California’s market experiment postponed price increases for its consumers, but granted them no pardon. Realizing too late that its market structure was overly dependent on spot trading, California moved aggressively, but awkwardly, to secure needed power supplies through long-term proprietary contracts. Likewise, the Federal Energy Regulatory Commission (FERC) effectively terminated the California Power Exchange, the region’s largest hourly spot market, presumably because it disliked the messenger as much as the message. These quick fixes are likely to be regretted, however, because they bind the State to inflexible, high-cost supplies—the very thing it sought to eliminate when it restructured in 1998. Mature, healthy markets depend on a robust mix of spot and forward trading; in contrast, many of the actions taken by federal and state regulators actually reduce liquidity and reliability and will contribute to higher costs and prices.

Only a year ago California was frequently cited as a leader in energy market restructuring. Now politicians from Japan to Italy are rethinking their position on market liberalization, because obviously something has gone terribly wrong. Before concluding that market liberalization is the cause of California’s woes, however, it is essential to analyze the fundamentals of demand and supply. The overwhelming reason for high power prices is scarcity, borne largely from sharply higher than expected demand growth and the savage downturn in hydroelectricity supplies. The influence of any particular market structure is

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minor when a commodity is in severely short supply. In the end, consumers will experience the scarcity through increasing prices, shortages, or some combination. Public officials can exaggerate the problem by shifting blame or they can help mitigate pain by bold measures to encourage conservation and the responsible expansion of transmission and generation capability.

The rolling blackouts and contentious wrangling that have plagued the California energy scene for nearly a year are often portrayed as the symptoms of complex problems and an imperfect market structure. Nothing could be further from the truth; the problem is very simple. The richest state, in the richest country in the world, does not want to pay its bills.

The Collapse of Trade

Celilo station on the Columbia River is the northern terminus of the DC line that interconnects the electricity grids of Southern California and the Pacific Northwest. The Celilo station is aptly located at what was once Celilo Falls, where the Columbia River plunged over abrupt cliffs in a swirl of white water and spray, blocking navigation upstream. The falls are now covered by a subdued reservoir behind the The Dalles Dam.

Figure 1 – Celilo Falls in the 1950s
Celilo Falls was once one of the great trading hubs of the North American continent, where as many as 10,000 natives would gather to fish and trade. At the end of the Columbia Gorge, the falls marked the breach between the lush Pacific Coast with its blackish loam, wild rhododendrons, honeysuckle, roses, fern, moss and evergreen firs, and the bleak interior with its sun-bleached soil, barren lava, sagebrush oak, and pine. At Celilo Falls, the principal medium-of-exchange was dried salmon, preserved to carry families through long cold winters. Here the boat people from the Lower Columbia, Puget Sound and the Inside Passage would trade salmon for the Navajo’s bright turquoise and silver. They would trade for Aztec corn and the Buffalo hides of the Plains Indians. The Celilo Falls trading hub is only vaguely remembered, rendering it an ironic symbol for the possible demise of the Western power market.

![WSCC Interconnection](image)

The healthy benefits of trade that have been bestowed on the West’s power consumers are now threatened as confusion, mismanagement, fear, greed, and parochial interests govern decision-making. Trade is essential to the Western power system, because the transmission network was designed to take advantage
of diversity in seasonal load and generation costs. For the first two decades after
the North-South Intertie was built, the bulk of trade was arranged through long-
term exchanges and the sale of “economy,” or surplus hydroelectric power.
Through this trade, utilities in the South would make power available to utilities in
the North during the winter and the flow would reverse in the summer. The
interconnection also allows consumers and generators to take advantage of
significant differences in variable cost. The West’s transmission lines traverse
vast empty spaces to connect population centers with far-flung generation. Unlike
many of the power pools of the Eastern and Midwestern United States, the
Western power system has distinct directional flows. The benefits of exchange
and trade are substantial—the pieces fit together like a jigsaw puzzle, allowing
individual utility seasonal peaks to be smoothed and cost reduced.

Perhaps nothing is more revealing about the dependence of the region on
trade and the unfortunate myopia that accompanied it, than the analysis published
by the Northwest Power Planning Council in March 2000, just two months before
the disruptions began. In early 1999 the Administrator of the Bonneville Power
Administration alerted the Northwest Power Planning Council about the
possibility of an energy shortage. The Region’s reaction to the warning was tepid
and while the Council concluded that there was a 24% probability of not being
able to serve the load at some time before 2003 it also commented:

Bonneville’s White Book analysis is very valuable in terms of signaling the need
for concern. However, there are several assumptions that could result in the White Book
analysis painting an overly bleak picture. First, the analysis does not account for imports
beyond existing firm contracts. In reality, the Northwest is part of a Western system with
a good deal of seasonal diversity in loads that makes a certain degree of reliance on
imports a cost-effective choice. Second, the White Book analysis does not reflect how
the hydroelectric system can frequently (but not always) be operated to manage through
relatively short-term supply problems. Finally, the White Book chooses not to speculate
about possible new resource development.

The analysis demonstrated that the Pacific Northwest could be expected to
run substantial deficits – that is, rely on imports – from October to March unless
water conditions were well above average. It seems as if everyone in the Western
Systems Coordinating Council (WSCC) was planning on importing power during
peaks, but no one planned for exports. The WSCC is not just interconnected, it is
interdependent – much more so than the relatively self-sufficient systems in other
areas of the U.S. When trade collapses, each sub-region of the WSCC is forced to
rely on its own resources; apparent abundance is replaced by forced outages and
capacity constraints.

2 Most other U.S. systems have limited interchange capacity, even in key market areas like the New York
City metro area. The direction of flows in the WSCC, of course, varies with the season and other factors.
California represents less than half of the Western states’ electricity load, but, unfortunately, is the lynchpin of regional trade. California is the geographical hub connecting the winter-peaking system in the North with the summer-peaking system to the South. Moreover, the significance of California has been heightened over the last decade as the state has become more and more dependent on out-of-state imports to keep its system in balance. Thus, when the California power market tottered on the edge of collapse, the entire Western market suffered.

The parochial reversion to autarky underpinning California’s decisions to delay or impede the construction of generation capacity has proven addictive. On February 16, the Washington Energy Facility Site Evaluation Council turned down National Energy System’s application to construct a 660 MW gas turbine at the Washington-Canadian border. The Council determined that, “On balance, the significant environmental and social costs of the facility, if located at the site proposed, outweigh the resulting energy benefits it would provide only to the most competitive bidders of the Western states power grid.” Put another way, the Council concluded that local residents should not be expected to bear the environmental costs of a new merchant plant that would simply sell power for the highest price, presumably to residents of California. Both the decision and its underlying reasoning are chilling. In an interconnected market, reduced supply means higher prices for everyone, not just for Californians. Attempts by each state to husband local supplies are myopic and counterproductive.

**Market Fundamentals**

Virtually no one was prepared for the rapid demand growth experienced by Western states in 2000. Power generation, as measured by the Edison Electric Institute (EEI), increased 7.6% in one year. The pace was more than double the year before and radically different from the one to two percent growth rates that had been both the historic norm and the planned growth for the next 10 years. There were several reasons for the rapid growth. The summer of 2000 was hotter than the previous year, particularly in Nevada, Arizona, New Mexico and Utah; the early winter in December was much colder than normal. The sky-high growth rate is not, however, explained just by abnormal weather. Electricity growth rates have been higher than usual even in off-peak periods, driven by an overheated high-tech economy. The rapid creation of jobs has accelerated population growth at the same time that the breakneck installation of servers, routing stations, and assorted communication facilities to support the Internet has kindled a rapid increase in power demand. This reflected a booming economy for the whole

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5 Edison Electric Institute, Weekly Power Output.
region: rough estimates of regional GDP growth from 1999 to 2000 are around 8% for all the Western states, with much of the growth centered in California.

Figure 3
Percent of Normal of Columbia River Water Flow, 1992 to 2000
Compared to an Index of Average WSCC Hydroelectric Generation

The general tightening of the West’s power supplies had also been obscured by much better than average hydroelectric generation in recent years. The combined Canadian/U.S. WSCC region is unique in North America for its dependence on hydropower. The resource provides about 40% of the region’s generation capacity and in most years over one-quarter of the energy. Most of the capacity is located in British Columbia and the Pacific Northwest, where hydro supplies over three-quarters of the energy. Capacity figures by themselves can be misleading, because the actual energy generated from the system is limited by annual water flow. The energy extracted varies substantially depending on the level of snow pack and reservoir fill that accumulates during winter months. In the banner year of 1997 total U.S. and Canadian WSCC hydro generation was 299 TWh, 99 TWh higher than generation in 1994, and equal to nearly one-half of California’s power demand or the output of more than a dozen nuclear plants. As Figure 3 demonstrates, WSCC hydro generation is dominated by Columbia River water flow. Generation from other hydro systems, such as the Colorado and Sierra

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6 The West Census region overlaps with the WSCC. Growth estimates are based on U.S. GDP growth during period adjusted upward to reflect greater population and job creation growth in the West.
7 Energy Information Administration, Statistics Canada, and NERC.
facilities, comes in relatively small amounts, often correlated to conditions along the Columbia.

Columbia water flows are now projected to be 54% of normal for the coming year. This is uncharted territory for the Western power market (1977 was the year of the last major drought). Because droughts are infrequent their occurrence plays havoc with the economics of alternative power supplies. During good water years many of the region’s oil and gas generators will lie idle or generate at prices not much higher than marginal cost. This means that capital costs will have to be recovered primarily during a period of drought. That, in turn, implies a spot market with many years of low-priced power, punctuated by episodes of extremely high prices.9

Following a string of high water years, supplies in 2000 were modest, with natural water flow lower than normal. In order to refill reservoirs, hydroelectric generation had to be curtailed. During the critical months of June, July, August and September, WSCC hydroelectric generation was an average of 6,079 MW per hour less than the previous year—roughly the output of 7 to 10 nuclear reactors. The drop in hydro supply occurred just when California and the Southwest were experiencing peak demand. Since California typically imports electric energy from the Pacific Northwest and the desert Southwest, the combination of lower hydro supplies and peak Southwest cooling demand meant that existing oil and gas generators inside the state had to be driven at exceptionally high rates. In California, overall power output increased 13%, as the state’s oil and gas generators were forced to displace imports that had been available in previous years. For the months of June through September of 2000, natural gas generation in Western U.S. states increased 62% from 1999. The consequence of the unprecedented increase in thermal generation output was a shortage of natural gas delivery infrastructure, a draw down of gas inventories, and a rapid depletion of emissions credits, which drove marginal production costs and prices to historic highs.

October brought cooler weather and loads dropped. However, due to the intensity of use in summer months, California’s oil and gas generators were in poor repair and many were down for maintenance, or were short on emissions credits. Likewise, nuclear and coal units scheduled maintenance or fuel replenishment during the normally low-demand shoulder season.

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8 Northwest River Forecast Center, March 29, 2000, “Early April Report.”
9 The alternative would be a mixed market with spot supplies and long-term contracts that include capacity payments. This would produce levelized prices over multiple years.
10 It is instructive to note that the loss of even one or two nuclear plants in Texas is sufficient to cause gas prices to increase.
11 Edison Electric Institute, Weekly Power Output.
12 Energy Information Administration.
California’s utilities and ratepayers might have slipped through the net, were it not for Murphy’s Law and mercurial Mother Nature. Winter in the Pacific Northwest, which is usually awash in rain, sleet, and snow, saw unusually dry weather, coupled with a severe early-December cold spell. The mere threat of the Arctic Front and its impact on gas inventories was enough to panic the market. In December the region experienced record price spikes, as illustrated in Figure 4. And, since that period bilateral prices in the Pacific Northwest (Mid-Columbia, Washington) have been the highest in the region, reflecting an increasingly serious water shortage, compared to the Southwest (Palo Verde, Arizona).

The consequences of the December price spikes were immediate and serious. California’s two largest utilities were forced to buy large volumes of power at prices that they could not pass on to consumers. Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) were already weakened from the summer spikes and the new round of price increases rang alarm bells on every trading floor in the region. As a consequence suppliers began to question whether or not they would ever be paid. On December 13, the “dirty thirteen” bluntly refused to sell to the California Independent System Operator (CAISO), which provoked a Stage 2 Emergency and threatened blackouts and chaos over the Christmas holidays. A day later on December 14, the Secretary of Energy, under

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13 At least as of April 2001, their fears have been confirmed. Most have received only partial payments for supplies delivered since November.
the auspices of the Federal Power Act, ordered power suppliers to continue sending energy to California. The Department of Energy’s (DOE’s) action was followed a day later by FERC’s December 15 order aimed at restructuring the California market, which among other things implemented “soft price caps.”

The combination of cold weather and Federal action took its toll. Hydroelectric generation in the Pacific Northwest increased in order to meet local load and to supplement California supplies. The consequence was a rapid drafting of reservoirs, increasing the risk that the expected low runoff in May, June, and July would not be adequate to refill the pools. The power crisis was exacerbated in December by a record-setting cold spell in the South, Midwest and Atlantic states, which severely strained natural gas inventories and delivery systems across North America, and particularly in California.

As the WSCC entered the shoulder season in February and March 2001, the sense of crisis and urgency abated for a short period. Snow levels in the Sierra Nevada range improved to near normal, but precipitation in the mountains feeding the Columbia River drainage remained near record lows. Snow levels in the Cascade Mountains of Oregon and Washington are the second lowest on record. Thus, there is increasing concern about the ability of the region’s generation resources to meet summer peaks. For this reason, spot prices remain high and forward prices for the summer have risen significantly. The problem is exacerbated by the fact that California is unprepared to cope with high load levels, its interruptible load program having been effectively suspended since early 2001. Virtually none of the long-term contracts entered into by the California Department of Water Resources will begin delivering power until late in 2001 or 2002. The cost for California to procure power on the spot market from June through September will likely be no less than $2 billion per month and if the summer is hot or if Qualifying Facilities (QFs)’s are allowed to charge spot prices, that figure could approach $4 billion. Even with the 3¢ per kWh rate hike of March 26, funds are inadequate to meet such expenses. The state controller has forecast that the cost of power purchases by the state will exceed $26 billion in the next eighteen months and will likely lead to a deficit of up to $7 billion in the state budget next year (from the current surplus).

California’s Market Structure

The restructured California power market had two key characteristics that would prove to be its undoing:

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14 The soft price caps set a maximum purchase price of $150 per MWh unless higher prices could be justified on a cost basis.
• The first was a freeze on retail electricity rates charged by the state’s three largest utilities for a transition period of approximately four years, which in effect disenfranchised marketers who could sell neither cost reduction nor risk management. The retail price freeze was part of a complex deal between the utilities that wanted to recover stranded costs and consumer advocates that wanted immediate benefits from deregulation for all market segments. In addition to the rate freeze, consumers received a 10% rate cut that was funded by refinancing utility debt.

• The second was excessive reliance on the California Power Exchange’s (CalPX’s) day-ahead and real-time spot markets for wholesale purchases, while risk management was discouraged.

Under the deregulation scheme, California’s utilities were allowed to recover stranded costs by pocketing the difference between what they paid for wholesale power—originally estimated to be approximately $25 per MWh—and what they could pass on to customers with frozen retail rates—approximately $55 per MWh. The monthly rate of stranded cost recovery, along with a fee for use of wires and other charges, was also charged to companies participating in the “direct access market,” selling retail power directly to consumers. In order to jump-start a competitive market the California Public Utility Commission (CPUC) ordered the utilities to sell many of their generating assets and buy and sell exclusively from the CalPX. The first generating units sold were considered the high-cost “dogs” of the utilities’ portfolios, primarily antiquated oil and gas turbines used only to meet peak loads.

Following the transition period (not to be more than four years) any stranded costs not recovered would be wiped from the books and the requirement to buy and sell power from the CalPX would expire. Utilities would be allowed to pass on the wholesale cost of electricity plus distribution and transmission costs. The retail rate freeze was to end either at the end of the transition period or when stranded costs were recovered, whichever came first. In the case of San Diego Gas and Electric (SDG&E), the utility received a much better price for its generating units than anticipated, and its rate freeze ended in the Fall of 1999. Thus, when wholesale prices spun out of control in the summer of 2000, the extra cost was passed right along to San Diego consumers who watched, horrified, as retail rates more than doubled in the early summer months. SCE and PG&E had not yet claimed stranded cost recovery, so their customers’ rates remained frozen, with the utility absorbing the loss. With alternative suppliers unable to beat the capped retail rates, the direct access market responded in a predictable fashion; customers flocked back to the price-capped utilities. The return of retail customers accelerated the utilities’ cash drain.
Critics of the California market structure have noted that it is suicidal to allow flexible wholesale prices when retail prices are frozen. This is, however, a simplistic critique. SDG&E’s flexible retail rates were the cause of the crisis for the other two utilities. Consumer reaction in California was so deep-rooted and angry that politicians and regulators would not accept rate increases as a solution, thus setting up SCE and PG&E for insolvency. The real problem was the design of the California market, which mandated the sale of utility generating assets, while blocking development of retail market competition and risk management.

The Devil’s Elbow

Since the 1970s, oil and gas markets have transformed themselves into highly efficient and sophisticated commodity markets. Spot transactions are at the heart of these markets, and determine the daily flow of energy from suppliers to consumers. Although the system is highly efficient, it can be risky. This is because the demand for energy is highly insensitive to price in the short-run—nearly straight up and down on a chart. In the short term, consumers will pay almost anything for heat, light and motion. Prices are kept reasonable, because supplies are usually abundant. In fact, most of the time the supply of energy seems to be infinite, and is infinite, in effect, until demand approaches production capacity. Once capacity constraints are reached, the supply curve switches from a flat plane to a vertical pillar. At the transformation, energy prices explode. Abundant surplus turns to critical shortage quickly and without much warning. The kink in an energy supply curve is the “devil’s elbow” and is the principal cause of volatile energy prices.

When faced with critical demand and uncertain supply, it is wise to buy insurance. Such prudence seems to have escaped the attention of California’s regulators. California’s deregulation plan was based on the assumption that private entrepreneurs would offer “contracts for differences” (CFD) to moderate swings in spot prices. This market never developed in part because the three largest participants, the investor-owned utilities, were discouraged from such activity. Spot purchases were deemed per se reasonable, but the treatment of profits or losses from a CFD or New York Mercantile Exchange (NYMEX) futures contract (even after recovery of stranded costs) was purposely left vague. After its stranded costs had been recovered, SDG&E petitioned the CPUC for performance-based ratemaking (PBR) that would have provided an incentive for the utility to do better than CalPX prices. The CPUC turned down the request and San Diego stuck to the spot market.¹⁶

Recognizing the chasm in market structure, the CalPX introduced block forward contracts in 1999, which allowed participants to purchase peak power months or quarters in advance. These contracts were no different than a bilateral
forward contract, except that the CalPX was the intermediary and pricing was transparent. Since the power was procured through the state-sanctioned exchange, the purchases were considered per se reasonable. Nonetheless, the CPUC put strict limits on the volume of forward power the utilities could buy, limiting participation to the utilities’ “net short position,” which was defined on average quarterly volume. This left the utilities vulnerable to daily and hourly peaks—the very period of times in which protection from price spikes was critical. As late as July 2000, the CPUC continued to enforce strict limits, and turned down SCE’s request for open-ended participation in CalPX forward markets.

The reluctance of California officials to encourage forward markets flows from their experience with the gas market. In the 1980s and early 1990s, long-term gas prices were usually much higher than spot prices, because the industry had vastly overbuilt production and transportation facilities. Also, as the volume of spot gas trading grew, the market matured, liquidity blossomed, and spot transactions proved reliable. Spot gas prices would spike, but only for short periods in response to pipeline outages or unusual weather. There is no question that California’s reliance on spot gas markets for over a decade was beneficial to its industry and utilities, but it did not follow that the same posture would work for the power industry, whose markets were immature and spare capacity depended on an unpredictable hydro supply. In addition, the gas market transition from bundled services for retail customers to unbundled supply occurred over a ten-year period, starting with the largest and most sophisticated customers.

Energy and Capacity Shortages

In thermal electricity systems, power prices tend to extremes—prices spike to extraordinary levels when load reaches system capacity or fall down to more or less the cost of fuel when demand abates. Hydro systems can be very different. Usually there is more than enough capacity to meet peak demand, however, the system can be “energy” constrained. The energy constraint arises because natural stream flow plus the water stored in reservoirs may not be adequate to meet the load over an annual cycle. In a market setting, this means the alternative cost of generating power today depends on the value foregone of generating some time in the future. There are, of course, all kinds of other constraints—fisheries management, shipping, irrigation, recreation, etc. Nonetheless, hydro systems ought not to produce pricing extremes except in the most extreme high demand/low supply situations. In theory, if water (rather than capacity) is short, both off-peak and on-peak prices will rise, until the current price is more or less equal to the net present value of expected prices in the future. In this case, however, expectations for load and replacement energy are critical, because precipitation in future water periods is unknown.
Since market disturbances began in May 2000, the Western power market has been acting like an energy-constrained hydro system. Prices often peaked in response to capacity constraints, but did not return to fuel costs plus a small margin. Instead off-peak prices have remained high, acting as if the system had an energy constraint. In fact, it often has. The fundamental increase in demand described earlier and the drop in hydro generation have meant that oil and gas peaking units have had to increase utilization far beyond expectations. These units, however, depend on the availability of fuel, storage capacity, and the pipeline delivery infrastructure. These constraints frequently limit the total number of hours, or proportion of time, a unit may generate. Most generators contract in advance for a given volume of gas, and arrange storage based on expected utilization. Sometimes they may simply not be able to exceed their planned level of utilization. Other times, over-generation means that they will have to rely on spot market purchases of fuel, pipeline deliveries, storage, and emissions credits. These constraints may combine to create an economic limit on the energy that can be produced. The limit can only be exceeded at very high price levels. Thus, off-peak prices do not decline because part of the cost of generating is the opportunity foregone to sell into peak market conditions.

Often, there are outright restrictions on generation that arise from environmental regulations that limit annual emissions or by local ordinances that constrain activity to particular times of the day or season. For example, the City of Pasadena limited the use of combustion turbines in its jurisdiction to 300 hours per year in 2000. The City has recently increased the limit to 1300 hours per year. It has 226 MW of oil and gas fired capacity, but these generating units are old, heavily polluting, and not suitable for prolonged use. The problem of obtaining emission credits has also been identified as a major contribution to rising marginal cost. During the course of the summer emission credits in the South Basin environmental district increased more than forty-fold from a monthly average of $.85 in January to $36.93 per pound of NOx emissions in September.

How to Fabricate a Crisis

The rise in demand and contraction in supply that has gripped the Western power market was an unexpected and serious problem. It need not have been a tragedy. But the failure by politicians and regulators to heed or understand market signals has compounded the problem and created a crisis. Because a variety of federal and state decision-makers did not understand the nature of trade in the WSCC, their decisions have greatly inhibited the normal flow of electricity.

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16 Los Angeles Times and personal communication with City officials.
17 Monthly averages from the South Coast Air Quality District, as analyzed by Robert McCullough.
False signals. When prices first rose in May 2000, the CAISO had a $750 per MWh real-time price cap, high enough to have little or no practical impact on the market. As higher wholesale prices began to be rolled through SDG&E’s retail rates, however, politicians began to apply pressure on the CAISO Board to lower the cap to $250 per MWh. The Board compromised and on July 1 lowered the cap to $500, followed on August 7 by a drop to $250. The lower caps did have serious impacts, though not those intended by its architects.

Because the CAISO had price caps, the CalPX did not have to. Those purchasing power in the exchange would never bid more than the CAISO cap, instead they would shift demand to the real-time market. In a normal market this would not have been a problem—one or two days of dislocation. But problems in the Western power market compounded as shortages continued through most of June and into July and August. As a consequence, more and more of the load was served in the real-time market, which is highly prone to panic buying. On July 28 the phenomenon peaked, when as much as 28% of the load had to be met by real-time purchases.

The migration to the real-time market was compounded by the CAISO’s actions. Initially, the CAISO procured reserve capacity at a price up to $750 per MWh, and could pay up to $750 per MWh if the energy was called upon. As load migrated to CAISO markets, unscheduled demand became highly volatile which, of course, increased the need for reserves, taking energy out of day-ahead markets where the extra supply would have dampened prices. Moreover, the CAISO was authorized to make “out-of-market” purchases from out-of-state suppliers at whatever prices the market would bear. It did not take in-state suppliers long to discover that they could sell higher-priced power to marketers in Oregon and Arizona, which could then be resold to the CAISO. Normally power flows south from the Pacific Northwest to meet summer air conditioning loads. In the summer of 2000, day-ahead schedules indicated huge congestion differentials for moving power north instead of south. This was “paper” congestion, however, because the day-ahead contracts were resold to the CAISO in real time and the power never actually left the state.

Misallocation. The CAISO attempted to clamp down on such market aberrations by lowering the cap paid for reserves. As a consequence, reserve margins declined, signaling successive stage 1 and stage 2 emergencies. Dwindling reserve margins had other unintended impacts. Hydropower capacity is an excellent reserve facility, because it can generate almost instantly without the ramping-up time of thermal units. Hydro generators could not, however, offer capacity to the CAISO, because in the event of an emergency, they would be

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18 WWW.CAISO.COM
forced to generate even if reservoir levels dictated that the water be held back. As a consequence, bids into the CAISO reserve market were based on thermal capacity, which when unused took available energy out of the market.

In an effort to maintain reliability, the Northern California hydroelectric system was significantly overused. During November and December 2000, the CAISO complained that some of California’s reservoirs were drawn down to the intake valves, providing a vivid picture of sputtering sand and mud. These facilities, however, did more than just provide energy. Their location helps balance load and generation centers in the grid. The lack of balance increased congestion on “Path 15,” the major transmission line running between Northern and Southern California, once again reducing available energy.

Chaos in California disrupted normal trade flows in the Western market. When the new California power market opened in April 1998 its two principal load zones were Northern California and Southern California. Path 15, which connects the zones, was seldom congested. What little congestion occurred was usually restricted to a few off-peak periods in a south-to-north direction. The northerly flow allowed hydro reservoirs in the North to be refilled during off-peak periods by thermal units in the South. However, Path 15 was not the only way to move power from Southern to Northern California. Oregon is interconnected to California through its high volume DC line that runs from the Celilo Station to Los Angeles, and by AC lines that run from the Oregon border to Northern California. These lines can be used to bypass Path 15 and wheel power to Northern California. As the regional power crisis has unfolded, this bypass has seen less and less use, not for technical reasons, but to avoid the risk of default or underpayment. Power can only move on this path by changing title through multiple owners, which of course compounds financial risk. As the credit risk of selling to California’s utilities increased, trade in the WSCC dried up, exacerbating the crisis and pushing Northern California into rolling blackouts.

**Missed opportunities.** The response of regulators and politicians to the unwinding crisis has been astonishing. The gas and power prices increases in May could have been taken as a signal of looming infrastructure problems. Instead, the nearly universal reaction was to accuse suppliers of gaming, withholding supplies, conspiring, and jacking up prices. Obviously, new generating units could not be built in a few months, but California could have implemented conservation measures, industry buy-back programs, life-line rates or any number of policies aimed at bringing the market back into better balance. Even if suppliers were responsible for the price spikes, they would have far less leverage following the implementation of conservation programs. Instead, industrial interruptible programs were over-used in 2000 and early January 2001, and suspended altogether as the tariffed limit on interruption time was approached and customers
protested to the extreme penalty charges. The CPUC has changes finally underway but, given the time needed for customers to set up response efforts, the turmoil damages the effectiveness of the interruptible programs for 2001.

The price spikes experienced in November and December were unexpected, and they provoked a political response that led to a financial crisis. It was evident to SCE and PG&E that they would be unable to continue purchasing high-priced power if the costs could not be passed along to the retail market. Summer peak purchases had already exhausted most liquid funds and their borrowing capacity was rapidly reaching its limit. In November and December, SCE and PG&E applied for a rate increases in excess of 30%, the minimum they believed would be necessary to reassure lenders and allow them to continue purchasing power. The CPUC turned down the request and instead granted a temporary rate increase of approximately 7 to 15%, depending on customer class. The rate increase was so modest that it unraveled the tenuous finances of SCE and PG&E.

California’s utilities have three sources of supply—their own resources not sold off in the restructuring, long-term purchase contracts (mostly QFs previously approved by the CPUC), and outright purchases from Independent Power Producers (IPPs). The deregulation scheme required the utilities to purchase their loads from the California Power Exchange during a four-year transition period. In order to ensure a robust and liquid exchange, the utilities’ resources and contract purchases were also bid into the exchange as supply. The CalPX price, used for valuing utility supplies, simply washed out. The important cost components for the utilities were their own cost of generation, contract purchase prices, and incremental load served by net purchases from the CalPX or the CAISO. Typically, generation cost did not increase, but contract purchase prices did, because most were tied to spot natural gas prices. Thus, the actual costs of about two-thirds of SCE’s and PGE’s supplies were significantly above the prices that could be passed on to the consumers, even after the modest CPUC rate increase. In December, when the CPUC limited retail rate increases, they did nothing about wholesale prices in QF contracts, even when it became clear that the formula would result in valuations three to four times above the level included in retail prices. The nuances of the regulatory failing may have been lost to the general public, but it did not take long for Wall Street’s analysts and IPP suppliers to conclude that the utilities were headed for insolvency, thus propelling the state headlong into a financial crisis.

The FERC did no better in managing unfolding events, focusing on market structure rather than on market fundamentals. As a consequence, both the cause

19 As of April, the quagmire is still not resolved and most of the QFs have received only a tiny portion of their expected revenue. This has been especially difficult for cogenerators, who face extremely high natural gas prices and many have had to shut down.
and cure of California’s market collapse was misread. Beginning early in the summer of 2000, it was obvious that forward contracting should have been an integral part of the original market design. In their December 15, 2000 Order, however, the FERC jumped to the conclusion that there was a single market structure flaw: the utilities’ mandated dependence on purchases from the CalPX. The Commissioners concluded that, by terminating mandatory buy-sell, they could somehow terminate high spot prices. Nothing, of course, could be further from the truth. Prices in the CalPX simply mirrored spot prices in the far larger bilateral markets, which in turn reflected market fundamentals.

Along with ending mandatory purchases and sales in the CalPX, the FERC ordered the exchange to implement soft price caps, with no corresponding requirement for alternative suppliers in the bilateral market. The FERC Order, in combination with the inability of SCE and PG&E to pay for power purchased from the CalPX, caused the exchange to terminate its operations at the end of January 2001, and declare bankruptcy on March 9, 2001.

Closing

Crises create confusion, and confusion leads to poor decisions. Both federal and state regulators are deeply confused about the differences between contracts and markets. Pushing utilities (or State Agencies) into long-term purchase contracts does not eliminate the need for reliable and transparent spot markets: it makes them all the more necessary. Electricity demand, more than any other commodity, is subject to the vagaries of weather. If utilities plan to meet extreme demand peaks, either through their own resources or through contract purchases, they will frequently have substantial surpluses. Such surpluses can often be economically disposed through spot sales. In parallel fashion, if a utility is short, it may plan to supplement supply through short-term purchases. Which strategy will prove the most cost effective depends on the skill of the utilities’ planners and traders. In all cases, however, an interconnected region is better off to encourage diversity of strategies and trade. Otherwise, the consequence will be significant under utilized capacity and higher costs.

The WSCC was unprepared for the simultaneous onslaught of reduced hydro supplies and an unexpected spurt of demand growth in 1999 and 2000. The institutional framework for solving the shortfall was an immature and heavily regulated wholesale market. Despite the imposed constraints and market immaturity, the WSCC achieved what all markets are supposed to do. It reallocated resources and balanced the system, however imperfectly. The market has, however, failed in a more important arena. It is causing politicians, regulators, and the public to lose confidence in market liberalization and the deregulation process in the U.S. and worldwide. This would be an especially
disappointing outcome, because California’s energy problems are unique and should not be used as an excuse to return to inefficient and distorting regulation.

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