Simulation Scenarios for the Western Electricity Market

A Discussion Paper for the California Energy Commission Workshop on Alternative Market Structures for California

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Professor Andrew Ford
Program in Environmental Science and Regional Planning
Washington State University

Summary

This paper was written to promote discussion at a workshop on alternative electricity markets in California. Workshop participants will discuss changes on both the supply side and the demand side of the wholesale market. On the supply side, participants will comment on incentives to promote more timely investments by private developers. They will also discuss the appropriate role of the California Power Authority. On the demand side, participants will discuss ways to encourage electricity consumers to participate more actively in wholesale markets, and they will comment on the impact of the legislated freeze in retail rates.

This paper argues that competitive electricity markets are prone to the same cycles of boom and bust that appear in commodity markets and in specialized industries like real estate. The paper presents simulation scenarios of how boom and bust could appear in the western electricity system. The “business as usual” scenario envisions a system at the crest of a building boom and on the verge of a bust in wholesale prices. The system would then experience a lull in construction before the next building boom. Without fundamental changes in the wholesale markets, the next construction boom would come too late to prevent a decline in reserve margins and the reappearance of price spikes. If we continue with the current market structure, we run the risk of exposing the western electricity markets to another round of reliability alerts and price spikes.

This paper argues that western markets could be improved by capacity payments to promote more timely private investment in new power plants. The Power Authority could also make the needed investments, but it must be prepared for a large and permanent commitment.

On the demand side, the paper argues that removing the legislative freeze on retail rates does not lead to long-term improvement in wholesale market performance. The more effective approach on the demand side is to implement programs to allow selected customers to respond to wholesale prices in real-time.
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Introduction

The blueprint for a competitive electric industry in California was issued in 1994 and implemented by the Legislature in 1996. The new markets opened for business in 1998. By the summer of 2000, a full-blown crisis had emerged in the form of unprecedented outages and price spikes. The crisis conditions continued through the fall of 2000, spread throughout the west, and continued into the winter and spring of 2001. Then, to the surprise of many, chronic outages and price spikes did not appear in the summer of 2001. New power plants came on line, and many more entered construction. As the year 2001 draws to a close some are predicting that the current building boom will lead to a glut of electricity supply. It appears that the western electric system is experiencing the boom and bust pattern that has appeared in other industries.

Industries with Boom and Bust

Many industries have experienced persistent cycles of boom and bust. The cyclical tendency is especially strong in the commodities. A commodity is usually defined as an undifferentiated product, often supplied by many small, independent producers. Examples include mineral products (i.e. aluminum and copper), forest products (i.e. lumber and pulp) and agricultural products (i.e. coffee and cattle). The instability in the commodity industries is costly for each industry, for its customers and for the nations that depend on commodity exports for the bulk of their hard currency (Sterman 2000).

The commodity industries suffer from chronic instability despite the fact that their products may be stored in inventory as a buffer between production and consumption. Buffer stocks do not exist in the electricity industry because electricity cannot be stored (except at great cost). Lacking buffer stocks, the electric industry looks to extra generating capacity to absorb the variations in supply and demand. In this sense, the electric industry is similar to the real estate industry with the reserve margin in the electric industry corresponding to the vacancy rate in the real estate industry. The industries are similar in several other respects as well. Developers in both industries confront significant delays for permitting and construction. Also, both industries are capital intensive, so developers face the challenge of recovering high fixed costs. Real estate developers strive to recover their investment by renting space in a competitive market; power plant developers aim to recoup their investment by selling electric energy into a competitive market. But the two industries are quite different in age. We have less than a decade of experience with restructured electricity markets in the USA, but real estate has a long history of competitive markets.

The Real Estate Construction Cycle

The long history of real estate is dominated by a series of exuberant building booms and subsequent busts. To illustrate, Figure 1 shows the pattern of boom and bust documented in Homer Hoyt’s detailed account of land values in Chicago. The chart shows land values, new construction and business activity, all scaled in percent variation from a normal value. Land values show the greatest variation. For example, land was valued at 80% below normal in 1830; reached normal values by 1835; then shot off the chart. Within a few years, land values were 80% below normal. This was the first of five booms in land values over the one hundred year period. Hoyt’s data on new construction begins in 1854, and Figure 1 shows four construction booms in construction over the 80 years. The final boom in the 1920s was the most sustained with unusually high construction continuing in 1926-1928 even though land values were declining.

Hoyt described surges in population as an important external factor, but the key to the boom-bust pattern was the way investors reacted to the population surges. In a typical example, developers did not react in time to prevent land values from increasing far beyond the increase in population. The high prices then led to an exuberant response, described by Hoyt (1933, p 387) as follows:

*Developers scramble to build at many locations around the city, and a great many men work secretly and independently on a great variety of structures in many sections of the city. There is no central clearing*
house to correlate the impending supply of buildings with the probable demand, so that when all these plans came to fruition, an astonishing number of new structures had been erected.

This overreaction sets the stage for the bust: “Gross rents fall, and net rents fall even faster. Land values plummet, and foreclosures are everywhere.”

![Figure 1. Land values and construction cycles in Chicago. (traced from Homer Hoyt’s One Hundred Years of Land Values in Chicago.)](image)

Hoyt concluded his study by speculating that the “real estate cycle itself may be a phenomenon that is confined chiefly to young or rapidly growing cities.” But population surges are just one of many external factors that might set the stage for a boom and bust in construction. In more fully developed cities, the external factor may take the form of a surge in income, as happened in cities like Dallas and Boston during the 1970s. The Boston housing market was the focus of a modeling study to understand the developers’ response to surges in income and employment. For example, an increase in employment caused housing prices to rise and construction to increase. “Prices peak when so much construction occurs that the stock of housing overshoots its target; prices then decline. This process sets off a repeating cycle in prices, construction and housing stock” (DiPasquale 1996).

It is natural to attribute a particular building boom to an external event like a surge in population in Chicago or a surge in income in Boston. But a full understanding requires us to look at internal as well as external factors. Hoyt looked closely at developers’ decision-making in Chicago and concluded that there was no way for developers to keep track of the number of buildings that were under construction. When all the buildings were finally completed, “an astonishing number of new structures had been erected.” DiPasquale looked at developer’s decision-making in Boston through the lens of structural models. The model with the best statistical explanation of housing construction tells a similar story as Chicago – the developers simply built too much housing during the boom and “the stock of housing overshoots the target.”

The overbuilding observed in Chicago and Boston arises, in part, from developers ignoring or discounting the future impact of construction “in the pipeline.” The tendency to understate the impact of the “pipeline” appears in industries, ranging from “A to Z, from aircraft to zinc” (Sterman 2000, p. 792). In the case of real estate, developers from the 1980s and 1990s concentrated on picking the best location and bringing the project to market. Student interviews summarized by Sterman (2000, p. 702) revealed that developers focused on selecting an attractive building site, winning financial backing and navigating the permitting process. According to one developer:

*Location is a bigger factor than the macro market. I know it’s cliché but really the key to real estate is location, location, location.*
Unless prompted by the interviewers, none of the developers mentioned cycles in construction or the impact of the construction pipeline. When prompted to comment on construction cycles, developers admitted that they “never looked at cycles” or “really had no sense for cycles.” One developer responded:

*Quite frankly, I am lousy when it comes to cycles. I think they exist but don’t pay a lot of attention to them. There are too many other factors that affect supply and demand. External factors make it difficult to look at cycles. In fact, I think they probably negate them.*

The interviews revealed that developers would sometimes use computer models to keep track of vacancies, rents and cash flow. However, these models were not designed for learning about the dynamics of boom and bust. Their real purpose was to build the case for financing:

*Market analysis was not done for decision-making: it was done to obtain financing ... Frankly, during that period of time [the boom of the 1980s] you were concerned about getting the deal done and didn’t really care about cycles – it was all ego and pressure to do the deal.*

The interviewers also revealed a tendency toward herding behavior during the peak of the boom. One developer described the psychological pressures as follows:

*There is a tremendous pressure to follow the crowd. If you are standing on the sidelines and not making investments and your competitors are collecting fees and placing funds, what are you going to do?*

**Learning from The Real Estate Construction Cycle**

This brief review has focused on real estate developers’ decision-making to gain insight as to how construction cycles might unfold in the electric industry. As we think about power plant construction, it’s certainly important to account for the physical factors such as capital intensity and construction lead times and to account for the tendency of developers to not fully account for construction “in the pipeline.” We should also expect psychological factors to play a role in shaping investor behavior. The key psychological factors that contribute to instability in markets include a focus on external events, a tendency for “herding” and “groupthink,” and simple denial that cycles could exist (ERPI 2000).

Although we have learned to live with construction cycles in the real estate industry, it’s not at all clear that we should tolerate construction cycles in the power industry. A fundamental difference in the two industries is the flexibility of the demand side. In real estate, we deal with the periods of low vacancies and high rents by adjusting our demand for floor space. When rents are unusually high, we squeeze into smaller quarters and wait for the boom in construction to bring rents back to normal levels. In electric power, however, customers have little ability to react when reserve margins are low and prices are high. (When wholesale prices are high, we can’t “squeeze” fewer kilowatts through our appliances.) With the current market structure, our ultimate response to dangerously low reserve margins is to schedule rolling blackouts to protect the integrity of the system.

The extraordinary reliability requirement of the electric industry sets it apart from industries like real estate. The challenge for the workshop participants is to suggest changes in wholesale markets that will allow the electric system to grow without the periods of tight supply that appear during the course of a construction cycle. The west needs new market structures that will avoid a replay of the price spikes and outages that appeared in 2000-2001.

**History of the Electric Industry**

It’s been over one hundred years since Edison invented the incandescent lamp and almost as long since Thomas Insull invented the investor-owned utility (IOU). The IOUs have managed to expand the nation’s generating capacity to keep reserve margins at safe levels during times of extraordinary change. The nation has experienced several wars, a major depression, an extreme drought and the IOUs have experimented with the introduction of complex, long-lead time technologies such as nuclear power.
Throughout this period, the IOUs have expanded the generating capacity to provide the margin of reserves needed for reliable service. Their success is due, in large part, to rate of return regulation and their clear obligation to serve the demand within their service territories.

With restructuring, we look to the markets to build the power plants that will be needed in the future. The IOUs obligation to expand capacity has been replaced by competition among suppliers. Some believe this decision was taken without serious debate. According to the San Jose Mercury News (Nov 30, 2000), for example:

*California’s deregulation effort was based on an unquestioning faith in the power of the free market. Despite official state forecasts that electricity demands would increase, for example, there was virtually no discussion of whether California’s generating capacity would keep pace.*

The crisis conditions of 2000-2001 have revealed the serious consequences of insufficient power plant construction in the western system. The lag in construction is documented in a recent report by the Northwest Power Planning Council (NPPC 2000) and in Senate Testimony by Steve Oliver (2000). Oliver suggests that the lack of construction might be attributed to numerous uncertainties that surround the transition to competitive markets. But he warned that the problem could be fundamental and persistent:

*The two-to-three year time lag in the market’s ability to respond to price signals with new generation supplies may reflect an inherent challenge for competitive electricity markets.*

Power plant developers around the US have responded to the market signals with a major increase in proposed projects. An EPRI review of proposed power plants in the US “anticipated that approximately 212 GW of new gas-fired capacity additions could appear over the next five years.” This would be approximately “two to three times more than would be needed to keep pace with demand growth. The supply-demand balance would be shifted significantly, and market prices would probably fall substantially below the level needed to support new construction.” The review concluded that different regions of the country “could move from boom to bust in just a few years” (EPRI 2000). Over time, the topic of boom and bust is appearing more frequently in the news. For example:

- An article in the Wall Street Journal (July 7, 2000) reports that Duke Energy Corp builds cycles of boom and bust into their own scenario analysis of electricity markets around the world. “There is little doubt there will be over-building. It will happen. The question is when?” says James Donnell, President of Duke’s North American Energy Unit.

- The New York Times (August 22, 2001) reports on proposals for 350 GW of new capacity that could be on line as early as 2004, said to be enough to boost the nation’s capacity by 50%. The article reported that many energy experts expect power plant construction to run in boom-and-bust cycles.

- According to an editorial in the Sacramento Bee (September 2, 2001), the goal of California’s new Power Authority is to build enough power plants for a 15% reserve margin, a policy said to provide “anti-blackout insurance” and to “break the cycle of boom and bust.”

- A recent article in Public Utilities Fortnightly (September 15, 2001) looks at the “fears of a coming glut in energy supply” to explain the recent loss in equity values in the power generation industry.

These recent articles have appeared around the same time as a major construction boom is occurring in the west. If we look back to the years prior to the building boom, however, we find only a few studies dealing with the prospects for a boom and bust.
Previous Studies of Boom & Bust

I have reviewed a variety of computer modeling approaches that could help one understand the potential for boom and bust in power plant construction. I found a few models that simulate new construction as an internal variable, but these relied on a combination of optimization and “perfect foresight” to calculate construction over time. This approach may appeal to a theory of “rational expectations,” but it precludes a serious consideration of boom and bust (ERPI 2000). A new approach was needed, one which represents “decision-making as it is, not as it should be, nor how it would be if people were perfectly rational” (Sterman 2000, p. 597).

I began the development of more realistic models in the summer of 1998. The first model represented the average annual energy loads and resources in the WSCC, the Western System Coordinating Council (Ford 1999). It assumed that power plant developers watch the general trend in spot market prices and extrapolate those trends into the future. The extrapolated prices were compared to the levelized cost of a new CC for purposes of permit applications and construction starts. These assumptions, when combined with the delays for permitting and construction, caused construction to appear in waves of boom and bust. These results were published near the end of 1999.

A few months later, the CEC released a report on Market Clearing Prices Under Alternative Resource Scenarios 2000 – 2010 (CEC 2000). By this time, a large number of power plant proposals had accumulated, and staff could see the early signs for a potential boom in construction. They designed a “rapid development” scenario and a “cautious development” scenario for power plant construction and used a production cost model to calculate market prices. Interestingly, their calculations revealed a bust in market prices in both scenarios. They concluded by emphasizing the problem of covering the total levelized cost of a new CC with the average annual revenues earned in the energy market:

A new generator’s profitability will depend largely on the prices it is paid for energy during the summer peak demand season, if it is relying solely on the energy market for revenue. Market clearing prices during the summer peak demand season may not reach a level necessary to sustain new market entry until reserve margins drop below historic levels usually regarded as necessary for reliable service.

This conclusion is of fundamental importance, and it has been reemphasized in the recent California Energy Outlook (CEC 2001, Appendix B) and in the announcement for this workshop.

My simulation of power plant construction was expanded in the summer of 2000 with a model to represent construction and market prices in a summer peaking system with approximately the same loads and resources as those in California. The model simulated market prices on an hour-by-hour basis to represent the combination of the PX day-ahead price and the ISO real-time price for energy. The new model allowed for several types of investors who would apply for permits and commit to construction. The simulations revealed that construction could appear in a steady, even fashion, causing power plants to come on line exactly in time to meet the profitability goals of the investors. But this was not the dominant pattern. The more likely pattern showed construction lagging behind the growth in demand, allowing prices to climb to surprisingly high values during peak periods in the summer. When power plants are completed, they tend to come on line in great numbers causing a bust in wholesale prices (Ford 2001). The previous article concluded that the lack of power plant construction is a western problem (not just a California problem), and it called for an expansion in the model boundary to include loads and resources throughout the west. The expanded model, the “Western Market Model,” is used in the remainder of this paper.
The Western Market Model

The western market model was constructed using the system dynamics approach which proved useful in the previous models of power plant construction. System dynamics was pioneered by Forrester (1961) and is explained in texts by Ford (2000) and Sterman (2001). It is valued as a strategic tool for a rapidly changing electric industry with high uncertainty and high risk (Dyner and Larsen 2001). The western market model is designed for highly interactive use to promote experimentation and discussion. The goal is general understanding, not precise forecasting.

The simulations begin in the winter of 1998, with information on existing generation taken from the WSCC. The model simulates a typical 24 hour day for the winter of 1998, records the results as representative of the winter quarter, and proceeds to simulate a typical day for the spring of 1998. (Further information on the hourly operations is given in Appendix A.) The model simulates the interval from 1998 to 2001 before proceeding into the future. The historical period is simulated to allow one to compare simulated results with historical results. It’s also useful to simulate the historical period to give the model time to develop the proper “momentum” as it enters the future.
Simulated Prices for the Past Four Years

Figure 3 shows simulated market prices over the interval from 1998 to 2001 with the vertical axis scaled from 0 to 400 $/mwh. The hourly prices tend to increase in the day and fall at night, but these hourly variations are not readily apparent in 1998 and 1999 because of the scale. The hourly variations are much more discernable during 2000 and 2001. The first price spike appears in the spring of 2000 (as highlighted by the button). The price peaks at nearly 200 $/mwh during the typical day in spring of 2000. Figure 3 shows larger and more persistent spikes in the remainder of 2000 and in the first half of 2001.

The model calculates averages over the 24 hours in a typical day for each quarter. These quarterly results appear in Figure 3 as abrupt changes when the model posts new results at the conclusion of each quarter. The quarterly price climbs to around 130 $/mwh in the summer of 2000 and even higher in the fall of 2000 and the winter of 2001. The winter price is around 250 $/mwh, nearly ten times higher than prices at the start of the simulation.

These prices may seem shocking, but they are similar to quarterly prices reported by the ISO (see Appendix B for more information). The model calculates averages over the entire year as well. The annual results appear in Figure 3 as abrupt changes when the model posts new results at the conclusion of each year. Figure 3 shows an average of 27 $/mwh in 1998, 26 $/mwh in 1999. The average for 2000 is 113 $/mwh.

The final curve in Figure 3 is the investors’ expected levelized cost of a new CC. This is displayed along side of the market prices to provide perspective. In the first two years, the model shows investors’ expectation for a new CC at 31.5 $/mwh. This is significantly higher than the average annual market clearing price in the first two years. The price of natural gas increases dramatically in 2000, and
The investors react with an upward adjustment in the expected levelized cost of a new CC. Figure 3 shows their expectation peaking at around 54 $/mwh mid way through 2001. This value turns out to be less than half the average annual price for 2000, and it is nearly five times smaller than the average price in the winter of 2001.

The lower portion of the main screen is filled with operational and navigation buttons. There are buttons to run or stop the simulation and a row of buttons to jump to other screens for setting the inputs or for viewing the results. Figure 4 shows the main screen for setting model inputs.

Initial loads are based on the WSCC data for each reporting area, and the user specifies the growth in demand using the four sliders in the upper left portion of Figure 4. The historical simulation assumes a general trend of 2 % annual growth in each of the four years. Variations from this trend are imposed to account for changes in the weather. For example, the summer of 1998 was somewhat hotter than normal; the summer of 1999 was somewhat cooler than normal.

Figure 4 shows four additional controls to allow one to impose the unusual reduction in loads that have appeared during the past few years. The top control is used in this simulation to lower northwest loads near the end of 2000 and into 2001. This represents the major shutdown in industrial loads (such as the aluminum smelters normally served by Bonneville).

Additional “demand inputs” in Figure 4 are the price elasticity of demand and lag for consumers to respond to changes in retail prices. The long-term price elasticity is set at 0.2 (which means that consumers would lower their demand by 20% if retail prices were to increase by 100%). The retail rate for the hypothetical distribution company is frozen at 87 mills/kwh, however, so there is no consumer response in this simulation.
The right side Figure 4 shows the key parameters for representing market design and market behavior. The first input is the price cap, expressed in $/mwh. I assume that the cap in the ISO real-time energy market serves as the defacto price cap in the California markets and for the entire western market. The historical simulation begins with the cap at 250 $/mwh. The cap was raised to 750 $/mwh in October of 1999, lowered to 500 $/mwh in July of 2000, lowered again to 250 $/mwh in August of 2000. These and other changes are represented by the "equation on" control for the price cap. A Proxy Price (similar to FERC’s use of a proxy price for “price mitigation”) is shown for comparison purposes.

The next control in the market inputs column is the “fractional increase in demand used as a proxy for including ancillary services.” The base value is 7%, which means that the actual demand is elevated by 7% before calculating market prices. The generating resources are bid into a market to serve the elevated demand, and the price is taken as an approximation for the energy price that would result when generators can bid into multiple markets. The slider allows this input to vary from 0 to 0.10. The value of 0.10 is appropriate if one wishes to be “conservative” in estimating market prices. The conservative approach was followed in FERC testimony by Kahn (2000) and in calculations by Hildebrandt (2000). Their conservatism was appropriate because they were estimating the extent of market power. For our purposes, however, it makes more sense to set the adjustment at a more realistic factor. I selected a 7% adjustment which corresponds to the WSCC guideline on reserves.

The remaining sliders shown in Figure 4 allow the user to control the extent of “strategic behavior.” Strategic behavior usually takes the form of physical withholding or economic withholding. The Western Market Model is designed as if the impact of strategic behavior can be represented by a user specified fraction of older gas units which are subject to economic withholding. To simulate competitive outcomes, one sets these fractions to zero, and all of the gas capacity will be bid at variable cost. Turning the California “equation on” assumes around 10% withholding during 1998, higher fractions in 2000. These "default values" were selected to give realistic prices, as explained in Appendix B.

Simulated Construction for 1998-2001

Figure 5 shows the results on the “CCs Under Construction” screen. The four variables are displayed on a graph scaled from 0 to 60,000 MW. The “paperwork on proposed CCs” grows to almost 45,000 MW by the end of the historical period. The first gray button is located to represent the 33,000 of proposed projects (either approved or in the formal review process) at the end of 2000. The next gray button shows a historical benchmark of 43,000 for paper work midway through 2001. The simulated accumulation of paperwork comes close to the two benchmarks.

![Figure 5. Simulated Construction Over the Past 4 years.](image-url)
The three red buttons represent benchmarks for new CCs under construction midway in 2000, at the end of 2000, and midway through 2001. The third button is open, so we can read that around 21,000 MW of capacity was under construction midway through 2001. Figure 5 shows that the simulated growth in CCs under construction comes close to all three benchmarks.

The two blue buttons show the total new capacity that has completed construction during the historical period. The first button represents around 1,000 MW on line by the start of 2000; the second button represents around 4,000 MW by summer of 2001. Figure 5 shows that the simulated growth in new capacity comes close to the two benchmarks.

The fourth variable displayed in Figure 5 shows the MW of CCs that would be in construction if investors were building new power plants to expand total generating capacity to keep pace with the 2% annual growth in demand. The construction interval for a new CC is around 24 months (EPRI 2000). Given this lag and given the size of the WSCC system, we would need to see around 5,500 MW under construction. Figure 5 shows that the simulated construction is well below the 5,500 MW in 1998 and 1999, well above in 2000 and 2001. In other words, we can summarize the historical results by saying that investors were

- Under-building in 1998-1999 and

The under-building in 1998-1999 is one of the main factors contributing to the severe price spikes in 2000-2001. One might wonder why we have not seen more MW of construction completed in time for their owners to benefit from the price spikes in the summer of 2000. With a 24 month construction delay, investors would have had to start construction midway through 1998 if they were to bring their plants on line midway through 2000. Perhaps they did not start construction at this time because of “opening market confusion.” After all, the California markets did not begin operation until the spring of 1998. On the other hand, one might argue that market rules were evident with the passage of AB 1890 in the summer of 1996. With the rules in place, a rational investor might have looked into the future and foreseen the large profits to be earned from starting construction midway through 1998.

The explanation of the historical under-building will shape the way one addresses the question of changing California’s wholesale market structure for the future. If one attributes the under-building to “early market confusion,” one might argue that we should retain the current market structure and hope the investors will be less confused in the future. On the other hand, if the under-building is attributed to a combination of factors that could reappear in the future, then we need to examine new market structures. The Western Market Model explains the under-building based on market fundamentals that could well reappear in the future.

**A Theory of Investor Behavior**

The diagram in Figure 6 shows the theory of investor behavior implemented in the Western Market Model. The model simulates the development process beginning with the application for a construction permit. After 12 months, the developer receives the permit, and the project enters a “site bank”. (The combination of CCs under review and in the site bank was shown in Figure 5 as “paperwork on proposed CCs.”) Approved projects give the developer an option to start construction, but there is no requirement that the developer must follow through on the proposed project.

The key decision is whether to start construction, and Figure 6 depicts the model’s theory of construction starts with some illustrative numbers that would apply during a period like 1998-1999 when natural gas was priced at around 2.50 $/mmBTU. Figure 6 shows the three assessments that investors conduct to arrive at the simulated construction starts:
• **Supply Assessment:** The model assumes that investors are aware of all of the capacity in the WSCC. They know the planned and scheduled outages of the thermal units, so they are able to estimate the thermal capacity during a peak day in the summer. The investors count the new CCs that have come on line in their assessment, but they may not count all of the CCs that are currently under construction.

• **Demand Assessment:** The model assumes that investors watch the trend in demand over time, and they use the trend to estimate peak demands in the future. Their forecast looks two years in the future since it takes two years to build a new CC. The forecasted peak demand is compared to the expected supply to get the expected reserve margin. In this example, investors are expecting a future reserve margin of 15%.

• **Market Assessment:** The model assumes that investors have access to production costing models that would allow them to calculate average annual market prices based the reserve margin. With a 15% reserve margin, for example, they might expect the future market to clear at 26 $/mwh. The model uses a highly nonlinear curve to represent the changes in estimated market prices based on the expected reserve margin. This particular curve is based on market price calculations with natural gas priced at 2.50 $/mmBTU.

Figure 6. The Theory of Investor Behavior Implemented in the Western Market Model.

In the illustrative example, the investors expect the market to clear at 26 $/mwh, but the full cost of a new CC is expected to be around 31.5 $/mwh. The model assumes some diversity of investor conditions, so some investors may start construction when expected market prices are somewhat below 31.5 $/mwh. But in this example, 26 $/mwh is simply too low for a significant fraction of the developers to begin construction. The model assumes that investors would be inclined to wait for expected conditions to
improve. With time, demand will grow, expected reserve margins will fall, and expected market prices will rise. When expected market prices are closer to the investors’ target for a new CC, they will turn their permits into actual construction projects.

The approach in Figure 6 is simulated continuously over time. That is, investors continuously update their assessments of supply and demand as simulated conditions change over time. If they do start construction, their own construction will shape their assessments in the future. This approach succeeds in explaining construction over the historical period. It explains the under-building in 1998-1999, and it does so without resorting to the argument that investors were inhibited by “early market confusion.” It also succeeds in explaining the over-building in 2000-2001. The next section shows the implications of extending this simulation into the future.

The Business As Usual Scenario

Several of the model inputs were adjusted from year to year during the historical period. For example, the price of natural gas increased rapidly in 2000 and early 2001 before declining midway through 2001. As another example, hydro generation was higher than average in 1998 and 1999 but well below average in 2000 and 2001. These variations are helpful during the historical period because they improve the comparison with historical prices, as explained in Appendix B.

However, as we extend the simulations into the future, it makes sense to adopt relatively constant assumptions in the interest of clarity. For example, I assume that hydro generation will be based on “average” conditions for the future. I assume natural gas will cost 4 $/mmBTU in California and 3 $/mmBTU in the rest of the WSCC. The thermal units will experience fixed outage rates, and the planned maintenance will be scheduled during the same seasons as in the past. Although there are many older power plants in the west (especially in California), there are no retirements of existing capacity in the business as usual scenario.

<table>
<thead>
<tr>
<th>New Capacity</th>
<th>Demand</th>
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<tbody>
<tr>
<td>CC Capital Cost = 600 $/kw</td>
<td>Initial Demands = WSCC data</td>
</tr>
<tr>
<td>CC Fixed Charge Rate = 14.5 %/yr</td>
<td>Demand Growth = 2 %/yr in all 4 areas</td>
</tr>
<tr>
<td>CCs Fixed O&amp;M = 10 $/yr per kw</td>
<td>Demand Shut downs = none</td>
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<tr>
<td>CC Heat Rate = 6,800 BTU/kwh</td>
<td>Customers on Real-time Pricing</td>
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<td>CC Permitting Interval = 12 months</td>
<td>Programs = none</td>
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<td>CC Developers’ Goal for Paperwork = 45 GW</td>
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<td>CC Developers’ Diversity = 6%</td>
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<td>CC Construction Interval = 24 months</td>
<td>Adjustment in Demand for A/S = 7%</td>
</tr>
<tr>
<td>CC Developers’ Attention to the</td>
<td>Capacity Payment = none</td>
</tr>
<tr>
<td>Construction Pipeline = 50%</td>
<td>Economic Withholding =</td>
</tr>
<tr>
<td>New Peakers (CTs) = none</td>
<td>20% of older gas capacity in CA</td>
</tr>
<tr>
<td>New Wind = 530 MW in NW</td>
<td>QFs Shutdown (credit crisis) = none</td>
</tr>
<tr>
<td></td>
<td>Price Cap = 200 $/mwh</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Existing Capacity</th>
<th>Fuels and Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal Capacity = WSCC data</td>
<td>Natural Gas Price in California = 4.00 $/mmBTU</td>
</tr>
<tr>
<td>Forced Outages = fixed</td>
<td>Natural Gas Price in NW, RM, SW = 3.00 $/mmBTU</td>
</tr>
<tr>
<td>Scheduled Outages = fixed</td>
<td>Cost of NOx Credits = 0 $/mwh</td>
</tr>
<tr>
<td>Hydro Capacity = WSCC data</td>
<td>Coal Price in RM, SW = 0.75 $/mmBTU</td>
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<tr>
<td>Hydro Generation = “average year”</td>
<td>Coal Price in NW = 1.00 $/mmBTU</td>
</tr>
<tr>
<td>Hydro Shaping = fixed</td>
<td>Coal Price in CA = 1.25 $/mmBTU</td>
</tr>
<tr>
<td>Retirements = none</td>
<td></td>
</tr>
</tbody>
</table>

Table 1. Long-Term Assumptions for the Business As Usual Scenario.
The new capacity will come from private investment in the CCs. There are no investments by the California Power Authority, but I do include Bonneville’s commitment to 530 MW of wind capacity in the northwest. The scenario assumes that a price cap will remain in place and that economic withholding will remain at the values found useful in explaining historical prices. There are no capacity payments; no real-time pricing programs; and retail rates are frozen.

**Simulated Construction**

Figure 7 shows the simulated construction in the business as usual scenario. The scenario envisions that investors will wish to maintain the paperwork at the amount accumulated over the past few years. The total paperwork remains at approximately 45,000 MW from 2002 through 2009. This is a combination of projects under review as well as projects in the site bank. As permits are granted, the bulk of the paperwork will be in the site bank.

The red curve in Figure 7 shows that CCs under construction peaks near the end of 2001. From this point forward, construction completions are greater than construction starts, and the total MW of CCs under construction declines. This simulation suggests that we are now at the crest of the current building boom. As the construction is completed during 2002 and 2003, installed CC capacity will grow to around 27,000 MW by the start of 2004. Installed capacity remains at this value for the next three years because of a lull in construction during 2003, 2004 and 2005. Figure 7 shows a second wave of construction beginning in 2006 and peaking near the end of 2007.

The green curve shows the “CCs in Construction to follow 2% growth.” This is the hypothetical amount of construction that may be used to judge whether investors are over-building or under-building. We are currently in the midst of a building boom, and the actual construction is well above the hypothetical construction. This over-building situation continues until midway through 2003. For the next three years, however, the scenario envisions construction below the levels needed to keep pace with demand. This lull in construction arises when investors again arrive at pessimistic market assessments (similar to the assessment depicted in Figure 6). During this interval, investors are reluctant to start construction, even though they hold a huge number of approved permits. According to this scenario, investors hold off on construction starts until 2006 – 2007. This second wave of construction causes installed CC capacity to grow again in 2008-2009. By the end of the simulation, there is 43,000 MW of installed CC capacity in the west.
Simulated Prices

Figure 8 shows market prices in the business as usual scenario, with the vertical scale running from 0 to 400 $/mwh as in the previous display. The simulation indicates that hourly variations for typical days in 2002 and 2003 would be much smaller than the variations in 2001. Figure 8 shows the quarterly prices continue to decline during the interval from 2002 to 2004.

Figure 8. Simulated Prices in the Business as Usual Scenario

Figure 8 shows the average annual price in black. The annual price is updated at the end of each year, and the results appear as abrupt changes in Figure 8. The average price for 2000 is 114 $/mwh; the average for 2001 is even higher, at 129 $/mwh. The construction boom allows for much lower prices for the interval from 2002 to 2005. The average in 2002, for example, is 39 $/mwh. By 2003, the average annual price is down to 34 $/mwh. At this level, the annual price is slightly below the investors’ expected cost of a new CC (which is at 35 $/mwh).

An important result from the business as usual simulation is the reappearance of price spikes in the years 2006 and 2007. The spike in 2006 exceeds 100 $/mwh; the spike in 2007 is around 175 $/mwh. These contribute to an increase in the quarterly and annual prices. In 2007, for example, the average annual price is 41 $/mwh, somewhat above the investors’ expected cost of 35 $/mwh for a new CC. The magnitude of these price spikes is much lower than the spikes during 2000 and 2001, but their timing is similar. The spikes in 2000 and 2001 appeared in the midst of a large building boom, just prior to the majority of the new CCs completing construction. The spikes in 2006 and 2007 appear in the midst of the second building boom, just prior to the next major increase in installed capacity.

Simulated Reserves

Figure 9 shows the simulated reserves in the business as usual scenario displayed on a scale from –40% to 120%. The Power Authority has declared the need to maintain reserves at 15% or higher, and this target is displayed for comparison. The reserves that would trigger a Stage I alert, a Stage II alert or a Stage III alert are also shown for comparison. The simulated “reserve margin” varies dramatically during the course of a day. This variable is defined as the current operating reserves divided by the current demand. Operating reserves are defined as all of the generation the system operator may call upon during each hour of the day.
Figure 9. Reserves in the Business as Usual Scenario.

Figure 9 shows the reserve margin falling to its lowest value when demand climbs to a peak value each day. For our purposes, the important comparison is the minimum reserve margin in each day compared to the 15% target by the Power Authority or compared to the values which would trigger an alert. Figure 9 shows that the Power Authority goal is seldom achieved, either in the past or in the future. Figure 9 shows that alerts would be declared in the year 2000 and 2001, but the building boom allows reserve margins to climb above 7% during the interval from 2002 to 2006. By 2007, however, reserve margins have returned to the low levels that would force the system operator to declare alerts.

Commentary

An important conclusion from Figure 9 is that the western system will not provide the reserve margins of 15% said to be necessary for a reliable system. Reserves would dip below 15% even during 2003 and 2004, the years immediately after the completion of the first wave of construction. By 2007 and 2008, reserve margins are back at unreliable levels, reminiscent of the situation in 2000 and 2001.

A second conclusion is that construction would appear in repeated waves of boom and bust. Figure 7 shows a second wave of construction cresting in the year 2007, around six years after the crest in the first wave of construction. The pattern in Figure 7 is quite regular, but this regularity comes from the constant assumptions adopted in this scenario. With more a complicated and erratic scenario, the waves of construction would appear in an irregular fashion.

A third conclusion, is that price spikes could reappear as soon as 2006 and 2007. These spikes are much less severe than the spikes in 2000 and 2001. The improved behavior arises because the scenario does not envision a replay of the “perfect storm.” For example, gas prices do not skyrocket in 2006 like they did in 2000. Also, hydro generation does not decline in the years 2006 and 2007, like it did in 2000 and 2001. These assumptions mask the underlying deterioration of the supply-demand balance that occurs during the lull in construction.
Figure 10 shows a variation in the opening scenario to unmask the difficult conditions that could emerge within the next decade. The new scenario makes two changes in the previous assumptions. First, I assume that the northwest could experience a “dry year” in 2007 (the region would lose around 6,000 average MW of generation). The dry year is timed to appear at approximately the same point in the boom-bust cycle as the dry conditions in 2000 and 2001. The second change is to lift the price cap at the start of 2004. We might envision the cap would be lifted because those who oppose price caps would win adherents to their view during the previous two years, years of low prices and declining construction.

Figure 10. Market Prices in a Business As Usual Scenario with the Price Cap Lifted in 2004 and a Dry Year in the Northwest Hydro System in 2007.

Figure 10 shows hourly prices spiking “off the chart” in the year 2007. Quarterly prices would climb to around 200 $/mwh, and the average annual price for 2007 would jump to 146 $/mwh, a value which exceeds the annual prices seen in either 2000 or 2001. Reserve margins (not shown here) would decline to levels lower than the simulated reserves in the years 2000 and 2001.

The price spikes in Figure 10 dramatize the problems inherent in the boom and bust pattern of construction. The simulation reveals that the western system could be “one dry year away” from a repeat of the crisis conditions that appeared in the years 2000 and 2001. If we do not implement fundamental changes in the structure of wholesale markets, we run the risk of exposing the west to another round of price spikes and rolling blackouts.
Supply-Side Scenario #1: New Incentives for Timely Construction

One of the factors contributing to the poor behavior in Figure 10 is the lack of timely construction by private developers. The price spikes in 2000 and 2001, for example, may be attributed to the under-building during 1998 and 1999. The spikes in 2006 and 2007 may be attributed to the under-building in 2004 and 2005. The fundamental factors that lead to the under-building have been depicted in Figure 6. During years when investors foresee adequate reserve margins they would expect market prices to clear below the fully levelized cost of a new CC. Under these conditions, they hold back on construction, waiting for market conditions to improve. By holding back, they set the stage for a larger building boom, one which will come too late to ensure that the west has sufficient generating capacity. This system needs new incentives to encourage investors to start construction earlier.

Background on Capacity Payments

Capacity payments provide incentives for generators to be available when the system needs capacity, and they provide “extra revenue to the generator to cover the capital and other fixed costs which are not covered by the energy price” (Hunt 1966, p 111). Many have argued that capacity payments are needed in the west (CERA 2001, McCullough 1998, Michaels 1997), and I have advocated their adoption in a previous modeling study (Ford 1999). On the other hand, several studies are silent on the topic of capacity payments (CBO 2001, CATO 2001, ERPI 2001). At this point, the California markets allow capacity payments only in the form of short-term payments for ancillary services.

Some may be opposed to the introduction of capacity payments because of the unfortunate experience in the early years after the UK decision to privatize their electric system. Their original pool established a capacity payment at approximately the product of the loss of load probability and the value of the loss of load (set at 3,000 $/mwh). This payment was important, contributing around 20% of the generators’ earnings in 1994 and 1995 (Newbery 1995). Unfortunately, it was extremely sensitive to reserve margin, making it vulnerable to manipulation by owners with horizontal market power, and it was eliminated in 1998 as part of a general overhaul in their trading arrangements. For our purposes, the work by Bunn and Larsen (1992) on the UK payment is instructive. They used computer simulation to demonstrate that a variable capacity payment would contribute to highly volatile patterns of construction. The simulated volatility did not arise from the exercise of market power. Rather, it was due to combination of factors including the size of the payment, the cost and lead-time of new CCs and the limits on investors’ ability to see into the future.

It’s evident from the business as usual simulation that the last thing we need in the western markets is additional volatility. This system needs additional incentives, not more volatility. We should avoid a variable capacity payment that could rise or fall with swings in the reserve margin. In the interest of stability, it makes better sense to provide the incentive in the form of a capacity payment that remains constant over time. The recent California Energy Outlook (CEC 2001) discusses the distinctions between energy and capacity. It then explains that capacity payments are one of the methods to “solidify the relationship between generation and load,” and it shows the energy prices required to meet an investor’s revenue requirements with capacity payments set at 20 $/kw per year or at 40 $/kw per year.

Simulated Impacts

The capacity payment control is shown in Figure 4. It allows the user to vary the payment from 0 to 100 $/kw per year. The high value would cover the entire fixed costs of a new CC (CEC 2001, p B-9). As an illustrative example, I have selected 20 $/kw per year, the smaller of the two examples studied by the CEC. I assume that investors use an expected capacity factor of 80% to include a $/mwh benefit in their profitability assessment. With this assumption, the capacity payments adds just under 3 $/mwh to the
energy price. This may seem like a small incentive, but it could turn out to provide the extra boost that investors need to start building earlier. (To envision the impact, imagine a 3 $/mwh upward shift in the market assessment curve shown previously in Figure 6.)

Figure 12 shows the simulated construction if the capacity payment is implemented at the start of 2003, one year after the crest in the construction boom. Figure 12 indicates that the total CCs under construction would continue on a downward trajectory during 2003 despite the extra incentive. But the downward trend is reversed near the end of 2003. New construction starts exceed completions around this time, and the MW of construction climbs during 2004. The new scenario then shows total CCs under construction declining in a gradual fashion, but never falling below the “hypothetical construction” which would appear if construction were to expand capacity to keep pace with 2% annual growth in demand. The important conclusion from Figure 12 is that capacity payments could lead investors to start building earlier. This, in turn, leads to less over-building at a later point in the simulation. The overall impact is a substantial reduction in the tendency toward boom and bust in construction.

Figure 12. Construction in Supply Side Scenario #1: Capacity Payments of $20 per kw-yr starting in 2003.

Figure 13 shows the reserve margins in the new scenario. As before, the best way to interpret this graph is to compare the minimum reserve in each day with the 15% target announced by the California Power Authority. The reserves in Figure 13 are somewhat improved (relative to the previous scenario) after the year 2005. By this point, the extra construction of new CCs allows the minimum reserves to dip only slightly below the target of 15%.

Figure 14 shows the market price implications of the capacity payments scenario. The “price” shown in gray in this display is the energy price. Figure 14 reveals that the variations in the energy price during the course of a simulated day would be greatly reduced by the introduction of capacity payments. The quarterly average prices and the annual average prices in Figure 14 are calculated from a combination of the energy price and the capacity payment. For purposes of comparison, the capacity payment is spread across 80% of the hours in the year, leading to an equivalent energy charge of just under 3 $/mwh. This is added to the market clearing energy price to get a total price for each hour. The average values of the total price are displayed in Figure 14, but the large scale makes it difficult to see the differences between this scenario and the previous scenario.
Figure 13. Reserves in Supply Side Scenario #1: Capacity Payments of $20 per kw-yr starting in 2003.

Figure 14. Prices in Supply Side Scenario #1: Capacity Payments of $20 per kw-yr starting in 2003.
Figure 15 shows a comparative graph of the quarterly average prices from the two scenarios. The vertical scale has been reduced to 120 $/mwh to make the differences easier to see. Two buttons are added to aid in the interpretation. The higher prices button stretches from 2003 to 2006 to alert us that total prices would be higher during the first three years after the capacity payments are introduced. This is the time period when no additional generating capacity has come on line, so the market price of energy is the same as the previous scenario. The additional 3 $/mwh (which is paid to all generators) causes the increase in the total wholesale price.

The lower prices button is open in Figure 15. It stretches from 2006 until the end of the simulation. The reduction in prices is made possible by the extra generating capacity that is constructed in the new scenario. The additional capacity shifts the balance of supply and demand to such an extent that the system operator is able to meet the energy needs with prices that are more than 3 $/mwh below the energy prices in the previous scenario. The total price benefit is particularly evident in the summer of 2007, a time when price spikes appeared in the business as usual scenario.

**Commentary**

These results indicate that the problems of boom and bust could be reduced if private investors receive an additional incentive in the form of a fixed capacity payment. A modest payment of 20 $/kw per year is shown to break the cycle of boom and bust that would appear in the business as usual scenario and to lead to higher reserve margins. The payments would lead to an increase in wholesale prices in the years immediately following their introduction. The payments could then lead to lower wholesale prices because of the construction of additional generating capacity.
Supply Side Scenario #2:  
The Power Authority Commits $5 Billion

Workshop participants will discuss the role of the California Consumer Power and Conservation Financing Authority, hereafter referred to as the “Power Authority.”  The Power Authority was created by SB 6 which calls on the new agency to “achieve an adequate energy reserve capacity in California within five years.”  SB 6 passed the Senate and was approved by the Governor in May of 2001.  The Power Authority was in operation by August of 2001.

Background

The Power Authority has broad powers under SB 6. It could contract with private companies to build plants or it could seize plants owned and operated by private generators. The agency is funded with up to $5 billion in revenue bounds that would be sold to investors and repaid by electricity ratepayers (Contra Costa Times, August 13, 2001). But how should it exercise these broad powers?

S. David Freeman, Chairman of the Board of the Power Authority, is said to favor an activist and enduring role (Contra Costa Times). According to an editorial in the Sacramento Bee, Freeman says his goal is

simply to build enough power plants to provide a 15 percent reserve – anti-blackout insurance, he calls it – that would break the cycle of boom and bust and serve as the backup generator for the state.

Some argue that the Power Authority should act as a “builder of last resort.” According to the Contra Costa Times, this is the view of Governor Davis who is said to have “faith in the private sector following through with building a record level of generation.” Others say that the Power Authority should follow the example of the New York Power Authority, whose purpose is to “correct an imbalance between supply and demand and provide low-cost power” (Dow Jones Newswires, August 15, 2001).

The creation of the Power Authority has changed the basic structure of the California markets. We now have a hybrid market with a mix of public and private investment. The argument for the public investment can be made in simple, clear terms. According to Freeman (Sacramento Bee):

Somebody has to build power plants. If they don’t, we will.

If the Power Authority succeeds in building reserves to 15%, however, some question whether that success will discourage private investment. According to Severin Borenstein, director of the Energy Institute at the University of California at Berkeley,

Once you start an organization like this, it can be very hard to stop it.  
It’s a real concern that it could turn into the central power player in the California power market.

The Power Authority website describes its challenging mission -- to “ensure sufficient surplus of electricity so that Californians never again face electricity shortages.” The website argues that the agency can act when necessary to “supplement” private enterprise efforts; it confirms the 15% goal for reserve margins; and it calls for a diverse power portfolio that includes renewable resources. The website reports Letters of Intent for 1,219 MW of wind capacity and 1,846 MW of peaking capacity. It also reports 5,968 MW of peaking proposals that are slated for further evaluation.
The Western Market Model may be used to examine the role of the Power Authority by constructing a scenario that attempts to follow through on the goals of building reserve margins and diversity. The Power Authority’s investments will be scheduled during the time period when private investors are reluctant to invest. In this sense, the Power Authority could be viewed as a “builder of last resort” or as a “supplement” to the investments by private developers.

Simulated Impacts

Figure 15 shows Power Authority projects which would use the $5 billion in funding. The scenario envisions 2,000 MW of wind construction starts over the next two years. The model assumes that wind machines cost 1,000 $/kw and require 24 months for construction. Once operational, they are bid into the market as “must run units” and operate with a 33% capacity factor. The wind portion of the Power Authority portfolio would consume $2 billion in capital commitments.

The other $3 billion is committed to 8,000 MW of peakers. The peakers are assumed to be single-cycle, gas burning units which cost 360 $/kw to construct (CEC 2001, p B-9). Their construction interval is quite short, so the model makes them available for operation at the end of the quarter when their construction is started. Their heat rate is 9,300 BTU/kwh. With natural gas priced at 4 $/mmBTU in California, their fuel cost would be around 37 $/mwh. Their variable O&M is 4 $/mwh, so they are bid into the market at around 41 $/mwh.
Figure 16 shows the reserve margins in the new scenario. These results should be compared with Figure 9 to learn the impact of the Power Authority commitments. This comparison reveals that the Power Authority's actions would allow the minimum reserve margins to reach the 15% target level by the 2003, one year sooner than this goal is achieved in the business as usual scenario. Figure 16 shows that reserve margins would remain above the 15% target during 2004, 2005 and 2006. By 2007, however, the reserve margin falls below 15% and remains below the target for the remainder of the simulation. The Power Authority planners would probably foresee the decline in reserve margins by 2004, and there would be pressure to exceed the $5 billion limit imposed in this scenario.

Figure 16. Reserves in the Power Authority Scenario.

Figure 17. Market Prices in the Power Authority Scenario.
Figure 17 shows the wholesale price implications of the Power Authority Scenario. Comparing these prices with the prices shown in Figure 8 indicates that the Power Authority projects would allow the west to avoid the price spikes that appear in 2006 and 2007 in a business as usual scenario. But there is cause for concern when price spikes reappear in the final year of the simulation. These spikes are another sign that generating capacity is not growing to keep pace with the growth in electricity demand.

Figure 18 shows why generating capacity is not growing as needed in the Power Authority scenario. Much of the new simulation is identical to the previous scenario – private developers are engaged in a major building boom that causes installed CC capacity to grow to around 27,000 MW by the start of the 2004. As before, there is a lull in construction in the years 2004 and 2005. These are the years when private investors are not inclined to build, so the Power Authority could make its commitments and argue that it is acting as the “builder of last resort” or that it is acting to supplement, not to substitute for private investment. The key differences show up in the years 2006 and 2007. During this period, private developers would be hesitant to start new construction. The success of the Power Authority in the previous years has shifted the supply-demand balance to such an extent that private investors do not foresee profitable conditions during the years 2006 and 2007. Rather than start construction, they wait for conditions to improve. As demand grows, conditions improve and a building boom begins around the year 2008. Based on previous simulations, we know that the western system will be vulnerable in the years just prior to the completion of this second building boom.

![Figure 18. Construction of CCs by private developers with the Power Authority Committing $5 Billion for Peakers and Wind.](image)

**Commentary**

This scenario suggests that the Power Authority could make the investments needed to ensure reliable reserve margins and to eliminate a reappearance of price spikes in the western system. By investing in renewable technologies (such as wind) and by timing the investments to occur when private developers are reluctant to build, the Power Authority might appear to be a supplement, not a substitute for private investment. But when the western market is simulated over a longer time interval, it becomes clear that the Power Authority commitments will eventually lead to a reduction in private sector investment. If the Power Authority is to deliver on its mission of ensuring reliable reserve margins, it should be prepared for a large and permanent commitment.
Demand Side Scenario #1: Unfreeze Retail Rates

Background

Retail rates have been frozen under California legislative mandates (AB 1890, AB 265), so electric consumers in California have been somewhat insulated from the dramatic changes in wholesale prices. Several groups have called on California to unfreeze retail rates (CBO 2001, CATO 2001, CERA 2001). They argue that higher rates would help the distribution companies recover the large expenditures made in the wholesale markets on behalf of their retail customers. They also argue that the higher retail rates give the customers a needed incentive to reduce load. Reduced loads could then lead to an improvement in the supply-demand balance and allow the wholesale markets to avoid sky rocketing rates.

Retail rates have not been frozen by legislative rules in the remaining areas of the WSCC. The remaining areas have experienced some retail rate response to the dramatic changes in the wholesale markets. The magnitude and timing of the response has been shaped by a variety of institutions such as the public utility commissions and the federal power marketing agencies. In some instances, retail rates have increased sharply, and there have been significant load reductions in response. In other instances, the threat of large rate increases has led to a negotiated closure of significant industrial loads.

The Western Market Model does not attempt to simulate the wide variety of institutional arrangements for setting retail rates in the west. But it does include a hypothetical distribution company which purchases electricity in the spot market on behalf of its customers. The DisCo is a large company, serving 10% of the retail demand in the WSCC. Its total retail rate was frozen at 87 mills/kwh in all of the previous simulations. This includes a 27 mills/kwh charge for generation and a 60 mills/kwh charge for a wide variety of expenses such as distribution, billing, competitive transition charges, and public purposes. The 60 mills/kwh charge is held constant and is considered sufficient to cover the DisCo’s expenses in all areas except generation.

The generation charge is fixed at 27 mills/kwh, approximating the sales-weighted annual average wholesale price in 1998. The 27 mills/kwh is sufficient to cover the DisCo’s spot market purchases in 1998 and 1999. But when the first price spikes appear in the spring of 2000, the DisCo must spend far more in the wholesale market than it recovers from its retail customers. The uncollected expenditures accumulate in a balancing account. The balance in the account climbs rapidly during the year, reaching the staggering value of $15 billion by the end of 2000. In the scenario with unfrozen rates, the generation charge will vary with changes in the wholesale prices. To keep the rate-making rules simple, the model sets the generation charge in the current quarter at the sales-weighted quarterly average price observed in the previous quarter.

Simulated Impacts

Figure 19 shows the total retail rate in the new scenario with the vertical axis scaled from 0 to 250 mills/kwh. The total rate remains close to 87 mills/kwh in 1998 and 1999. There are small variations during the first two years, as the retail rates respond to the changes in the wholesale markets. The large variations appear in the summer and fall of 2000 and in the winter of 2001. The retail rate peaks at 250 mills/kwh, nearly three times higher than the rate changed a year before. (A three-fold increase is similar to the increase temporarily imposed on retail customers in San Diego in the summer of 2000.)

Unfreezing the retail rates provides a tremendous benefit to the cash flow of the DisCo, but the lag in quarterly accounting means that the DisCo will still accumulate significant balances in the balancing account. By the end of 2000, for example, the balance of uncollected expenditures will reach $6 billion. During the course of 2001, the ratemaking rule allows the DisCo to “over-collect” on generation expenditures, and the balance of uncollected expenditures is reduced over time. These results are not shown here (since there is general agreement that the DisCos will benefit from unfrozen rates).
Figure 19. The Retail Rate in Demand Side Scenario #1: Unfreeze Retail Rates.

With the large rate increases shown in Figure 19, consumers would no longer be insulated from the prices in the wholesale market. But how would they respond to this massive rate hike?

The price responsiveness of electricity demand has been studied extensively, especially during the 1970s and 1980s. However, we should remember that very few consumers were exposed to three-fold increases in retail electric rates during the previous decades. Also, it’s important to remember that the 1980s and early 1990s was a period of major investments in energy efficiency, so the demand responsiveness may be less today than it was a decade ago.

More recent reports discuss the magnitude of the consumer response to higher rates, but their discussions do not necessarily lead us to an estimate of the price elasticity of demand. A CERA (2001) special report on the California crisis, for example, mentions responses with a price elasticity ranging from as low as 0.03 to as high as 0.60. The CATO Institute, one of the groups advocating higher retail rates, believes that a lower bound on the price elasticity is 0.023, based on the study of San Diego consumers by Bushnell (2001).

To illustrate the impact of unfrozen rates, I have selected an elasticity of 0.2. This is ten times higher than the "extreme lower bound" mentioned by the CATO Institute, but it is at the low end of the range of studies from previous decades. The demand response is implemented as a first order, exponential lag. The length of the lag time corresponds to around two-thirds of the response. The default value is two years based on a review of econometric studies from a previous decade.

Figure 20 shows the simulated consumer response in the form of “Demand Multipliers” on a scale from 0 to 2. The multipliers begin the simulation at 1.0. This means that the demand for electricity is the same as the demand in the previous simulations. The blue curve is the multiplier if there were no lag in the consumer response to higher rates. It drops each quarter, exactly in sync with the increases in retail rates. By the time rates have peaked at 250 mills/kwh, this multiplier has declined to 0.65. If there were no lags in the consumers’ response to higher rates, the demands in the WSCC would be 35% below the demands in previous simulations.
The red curve shows the actual demand multiplier used to adjust the demands in this simulation. It declines over time, reaching 0.97 by the end of 2000. This 3% response may seem small, but it could prove extremely important to the behavior of the wholesale markets. A 3% reduction across the WSCC lowers the demand by over 4,000 MW. This is an important response, one that is comparable to responses mentioned by those who have argued for retail rate hikes. (The CERA study of the California Crisis states that higher rates would have been extremely helpful if they lowered California demand by around 1,000 to 2,000 MW.)

The red curve in Figure 20 shows that the consumers’ response continues well beyond the year 2000. By the end of the year 2001, the multiplier is at 0.92 indicating that consumers have cut their demand by 8% compared to previous simulations. A significant reduction continues in the years 2002 and 2003 as well. (This enduring response makes sense when we think of improved appliances that would be installed in 2000 and 2001 and continue to deliver savings for the remainder of their operating lives.)

Figure 21 shows the demand for electricity in each simulated day, with the vertical axis scaled from 100,000 to 180,000 MW. With this scale, the lower portion of the daily demands is clipped off, so our eye is drawn to the peak demand that appear each quarter. The peak for the year appears in the summer. The summer of 1998 was unusually hot, while the summer of 1999 was unusually cool. This accounts for the noticeable decline in the 1999 peak. The most dramatic decline appears in the year 2001. This is the 8% consumer response to the increase in retail rates. Figure 21 shows that investors are responding to these trends as well.

The model assumes that investors are observing the trends in demand growth over time. Recall from Figure 6 that investors watch the trends in order to prepare a forecast of the peak demand that could appear on the system two years in the future. The demand forecast is combined with their assessment of future supplies to arrive at a price forecast and at a decision on construction starts. When demand begins to fall, the investors will see the decline and adjust their forecasts accordingly. This will lead to a different assessment of the future profitability of a new CC, and the end result could be less construction than in the previous scenarios.

The thin button in Figure 21 is located to help us appreciate the trend in the “Investors’ Peak Demand Forecast.” The left edge of the button is connected to their forecast prepared in the summer of 2004. The value is around 144,000 MW. This represents their best estimate of the peak demand that might
appear in the summer of 2006. The button is two years in width, so its right edge alerts us that 144,000 MW turns out to be reasonably close to the actual demand in the summer of 2006. If you perform similar checks elsewhere in Figure 21, you will see that investors don’t always see the future with such accuracy. Their forecast in the summer of 2000, for example, is an overstatement of the peak demand that appears in the summer of 2002. Their forecast in the summer of 2001 errors in the opposite direction. It turns out to be an understatement of the peak demand that appears in the summer of 2003. These errors are entirely plausible since investors can not see the future with “perfect foresight.”

Figure 21. Peak Loads and the Investors’ Forecasts of Peak Loads in the Scenario with Unfrozen Rates.

Figure 22 shows the power plant construction implications of a scenario with the consumers reacting to higher retail rates. The accumulation of paperwork is the same as in previous simulations, but the actual construction follows a different trajectory. The CCs under construction during 1998, 1999 and early 2000 is similar to previous simulations. Notice, for example, that the red curve comes close to the
first of three buttons showing historical benchmarks. But investors foresee a different future near the end of 2000, and the exuberance of the building boom is gone. The total of CCs under construction levels off at around 8,500 MW at the end of 2000. The simulated construction in this scenario is well below the 21,000 MW benchmark for construction midway through 2001. This simulation reveals that major building boom that is underway in the west would not have occurred in a scenario with a significant consumer response to higher retail rates.

Figure 23 shows the wholesale prices in the new scenario. The hourly prices show spikes in the spring, summer and fall of 2000. The summer quarter price turns out to be 123 $/mwh; the fall quarter price is 164 $/mwh. Figure 23 shows a price spike in the winter of 2001, but it is much less severe than we have seen in the previous scenarios. Prices decline during 2001 and remain low during 2002 and 2003.

![Figure 23. Simulated Wholesale Prices in a Scenario with Unfrozen Retail Rates.](image)

However, price spikes reappear around the year 2004 and 2005 in the new scenario. The spikes arise when generating capacity does not keep pace with the growth in demand. Figure 22 shows that the investors would be in the midst of a major building boom during 2004 and 2005, but the total installed CC capacity does not increase until around the year 2006. The extra capacity eliminates spikes during the year 2007, but not during the final two years of the simulation.

Figure 24 is a comparative graph showing quarterly average wholesale prices. The business as usual scenario is reported in blue. Wholesale rates exceed 125 $/mwh in the summer of 2000 and are near 250 $/mwh in the fall of 2000 and the winter of 2001. The scenario with unfrozen rates is shown in red. The price comparison shows major benefits in the wholesale markets when consumers respond to the retail rate hikes. Average prices in the fall of 2000 are reduced from 239 to 164 $/mwh, for example. Average prices in the winter of 2001 are reduced from 250 to 95 $/mwh. These are the short-term wholesale rate benefits stressed by those who have argued for higher retail rates.

The second half of Figure 24 reveals the longer-term impact of a scenario with unfrozen rates. Wholesale prices in the new scenario are higher in the years 2004, 2005 and 2006, the years when price spikes appear in Figure 23. For example, the average price for the summer of 2005 is around 50 $/mwh in the new scenario (versus 36 $/mwh in the business as usual scenario). The long-term impact of unfreezing retail rates could be increased prices in the wholesale markets.
Figure 24. Unfreezing Retail Rates Leads to Lower Wholesale Prices followed by Higher Wholesale Prices

The scenario with unfrozen rates assumes a major increase in retail rates, a significant consumer response to the rate hikes, and observant investors who adjust their construction starts as the expected profitability of new CCs changes over time. The resulting scenario shows a new pattern of boom and bust with major changes in wholesale prices during the difficult years of 2000 and 2001. The new scenario then shows rate penalties arising from the new pattern of boom and bust.

These results are somewhat difficult to interpret. Part of the difficulty stems from the fact that a three-fold increase in retail rates did not occur. Interpretation is also made difficult by the extraordinary conditions during 2000 and 2001. This was a period in which small changes in either supply or demand would lead to major changes in the wholesale prices. The scenario with unfrozen rates delivers some important reductions in demand during this crucial time period, and Figure 24 confirms that huge wholesale price benefits that would occur. But the scenario with unfrozen rates also leads to wholesale price penalties later in the simulation. The longer–term penalties are not as dramatic, but we know to expect less dramatic results in the years 2004 and 2005 (because the simulation is not designed for a replay of the extraordinary conditions of 2000 and 2001).

Commentary

I believe unfreezing retail rates will greatly alleviate the distribution company’s cash flow and credit problems during the periods of sky rocketing wholesale rates. But unfreezing retail rates does not appear to be effective in breaking the cycle of boom and bust. The scenario with unfrozen rates shows a different pattern of boom and bust, but the fundamental vulnerability would remain. The electric system would be exposed to the possibility of price spikes and outages similar to those shown in previous scenarios.

I concluded earlier in this paper that we could be “one dry year away” from a repeat of the crisis conditions that appeared in the years 2000 and 2001. I draw the same conclusion from the scenario with unfrozen rates. Simply allowing retail rates to respond to a poorly designed wholesale market is not the demand-side answer to the problems of boom and bust.
Demand Side Scenario #2: Implement Real-Time Pricing

Real-time pricing programs have been proposed to allow customers to participate more directly in wholesale markets. Proponents argue that electricity markets cannot be truly competitive unless both supply and demand participates. Real-time pricing would allow customers to feel the effect of wholesale prices and to reduce load during times of peak prices. These customers would benefit from major reductions in their monthly bills, and the remaining consumers would benefit from the improvement in the supply-demand balance during critical times.

Real-time pricing is also viewed as a method to reduce the exercise of market power. Hirst (2001, p 35) believes that customers who modify their usage in response to wholesale prices provide a “powerful way to discipline the market power that some generators would otherwise have during periods of peak demand.” Braithwait (2001, p 52) describes studies of market power in California and in the PJM system and reports that “completely unresponsive demand was one reason cited in both studies for the ability of generators to potentially exercise market power.”

Background on Real-Time Pricing

Real-time pricing has been recommended in several reports and papers (Borenstein 2001, Braithwait 2001, CATO 2001, EPRi 2001, Hirst 2001), and the California legislature has allocated $35 million for real-time meters. Programs in California seem to be based largely on a pilot study by Georgia Power Company and some recent experiments in government buildings in California (Levesque 2001). The Georgia Power program is a ten-year pilot study with voluntary participation by 1,600 customers representing around 5,000 MW of peak load. The customers’ bills are based on a two-part tariff. They are charged a regulated average rate for a base line load and a real-time rate for additional loads. The program has led to load reductions of around 800 MW during times when wholesale rates are especially high. This amounts to 17% load reductions during peak periods of the most expensive days. The recent measurements of load reductions in California buildings are said to closely match the results from Georgia (Levesque 2001, p. 16).

Braithwait (2001) is impressed by the Georgia results and has argued that real-time prices could be implemented in California, even with average retail rates frozen at legislated levels. He believes the benefits of load reductions during peak hours can be substantial, explaining that industry analysts sometimes estimate a “ten to one” ratio between load reductions and wholesale rate reductions. He uses a wholesale price model (based on cost information from the California ISO) to estimate a 24% reduction in wholesale prices from a 2.5% reduction in load. The “ten to one” result also appears in a discussion of the PJM interconnection by Hirst (2001, p 38) where “a 4 percent drop in demand could have cut the hourly price by almost 50 percent.”

Borenstein (2001) describes the potential benefits of two real-time pricing programs that might be implemented in California. One program would be targeted at large customers with 500 kw of load or higher. The metered customers would account for 21% of California peak load or around 8,000 MW. Borenstein gives a conservative estimate of 1,000 MW of load reduction during times of peak prices in the wholesale markets. A more aggressive program would place customers with loads at 200 kw or higher on real-time meters. They would account for around 30% of peak load. Borenstein gives a conservative estimate of 1,500 MW of load reduction.

To illustrate the benefits of real-time pricing, let’s consider what might have happened if California had moved to aggressively implement real-time pricing in 1998 and 1999. This scenario will allow us to judge the benefits under the difficult conditions of 2000 and 2001, a time when load reductions would have been extremely valuable.
Simulated Impacts

Imagine what might have happened if we had signed up California’s large customers for real-time pricing in 1998 and expanded to the smaller customers in 1999. The MW of RTP load would have grown to 8,000 MW by the start of 1999 and to 12,000 MW by the start of 2000. Furthermore, imagine that this level of price-responsive load is sufficient to discipline the exercise of market power. Figure 25 shows where these assumptions are implemented and viewed in the Western Market Model.

The model assumes that the RTP tariff is designed so that the customers “feel the effect” of wholesale rates in real time, and their response is simulated as the model proceeds through the 24 hours in a typical day. Information on the customers response is quite limited, so it makes sense to proceed with some simple, illustrative assumptions. For example, I assume, that RTP customers will not shed load unless the wholesale price reaches at least 100 $/mwh. If wholesale prices reach 150 $/mwh, the load reduction will be similar to the “conservative estimates” by Borenstein in which 12.5% of the participating load will be shed. The load reduction takes place after a one-hour delay for the customers to see the price and for their control equipment to react. If wholesale prices climb even higher, a larger fraction of the participating load will be shed. The maximum response is set at 50%, and this would be triggered by wholesale prices reaching 300 $/mwh.

This scenario envisions a maximum of 6,000 MW of load reduction if wholesale rates skyrocket like they did in the years 2000 and 2001. Figure 25 shows the simulated load reductions in red. We see the maximum of 6,000 MW appearing in the summer of 2000, followed by somewhat smaller reductions in the fall of 2000 and the winter of 2001. The full 6,000 MW appears again in the spring of 2001. No subsequent reductions appear until the years 2006 and 2007, and these are under 1,500 MW.

Figure 25. An Aggressive Real-time Pricing Program in California.
As in the previous demand side scenario, it makes sense to assume that investors are watching the implementation of real-time meters and that they are aware of the participating load. But how would investors estimate the fraction of the participating load that might be shed during peak periods in the future? For purposes of illustration, let’s assume that they believe around 25% of the participating load would be shed. (This is an arbitrary estimate which is twice as much as Borenstein’s “conservative” value of 12.5% but half as much as the maximum of 50%.) With 12,000 MW of RTP load, the 25% assumption translates to a 3,000 MW reduction in the investors’ estimates of future peak loads. This reduction is included in their demand assessment (depicted in Figure 6), so we should expect the new simulation to show a different pattern of power plant construction than in the business as usual simulation.

Figure 26 confirms that power plant construction would follow a different trajectory. The CCs under construction remain well below the three buttons which show the construction that has actually taken place during 2000 and 2001. A building boom materializes somewhat later than has actually happened with construction peaking at over 16,000 MW in 2002. This wave of construction would build the installed CC capacity to just over 20,000 MW by the start of 2004. A second wave of construction would appear around 2006-2007, increasing installed CC capacity to around 38,000 MW by the end of the simulation.

Figure 27 shows the wholesale prices in the scenario with 12 GW of RTP load implemented in time for the year 2000. We still see price spikes in the year 2000, but these are to be expected because of the assumption that customers must see the price spikes in “real-time.” (Recall that it takes a price spike of at least 100 $/mwh in real-time before RTP customers will shed load.) With this assumption, the RTP program does not eliminate price spikes; it reduces their duration and severity. Figure 27 shows that price spikes reappear in the years 2006 and 2007. These are years when investors are in the midst of the second building boom. The RTP program leads to some load shedding during these years as well, so the duration and severity of the spikes is reduced.

Figure 28 concludes the assessment of the real-time pricing scenario with a comparison chart of wholesale prices in each quarter. The previous simulation shows wholesale prices reaching around 250 $/mwh in the fall of 2000 and the winter of 2001. Real-time pricing shows prices at just under 125 $/mwh. The comparison shows a 50% reduction in wholesale rates from an RTP program with a maximum potential for 6,000 MW of peak load shedding. The 6,000 MW of shedding amounts to around 5% of the peak load in the WSCC. This portion of the comparison confirms the “ten to one” benefits described by Braithwait (2001) and by Hirst (2001).
Figure 27. Wholesale Prices in the Scenario with Real-time Pricing.
Figure 28 shows that wholesale prices decline rapidly in both scenarios in the year 2001. The quarterly average prices are rather similar for the remainder of the simulation. Some differences appear in the years 2006 and 2007, a period with price spikes in the real-time pricing scenario. For example, the prices for the summer of 2006 average to 49 $/mwh in the scenario with real-time prices versus 41 $/mwh in the business as usual scenario. These price penalties arise from the reduction in power plant construction in the real-time pricing scenario.

**Commentary**

The real-time pricing scenario is similar in several respects to the scenario with unfrozen retail rates. Both scenarios show important benefits in the wholesale markets during the difficult period of 2000 and 2001. The comparative charts in Figure 24 (unfrozen rates) and Figure 28 (real-time pricing) show comparable benefits from the load reductions that would have appeared had we had more active participation on the demand side. But the demand-side participation is achieved in a much more selective and targeted manner in the real-time pricing scenario.

The two approaches are contrasted below:

- As a method of gaining useful load reductions, unfreezing retail rates is a blunt, unwieldy instrument. In the scenario with unfrozen rates, for example, all of the customers in the WSCC were exposed to a three-fold increase in their retail rates. The price signal was based on the average prices observed over a previous quarter. Many customers are not capable of responding in a significant manner, so they face a three-fold increase in their bills. Others are able to respond, either with behavioral changes on investments in greater efficiency. Some of these reductions will appear in the next quarter, but the majority of the response will be spread further into the future. The end result is load reduction that appear during the bust phase of the boom-bust cycle.

- In contrast, real-time pricing is a precise, targeted instrument for gaining load reductions. It targets the customers with the most capability to respond (through voluntary participation), and it sends signals in real-time. In the simulation scenario shown here, the signal was based on the wholesale price observed in the previous hour. The customers would be equipped with automatic
control equipment to allow load shedding within the next hour. The load reductions appear in a
timely manner, and they reward the participants with significant reductions in their total bill.

I believe real-time pricing is a more effective and less intrusive means to engage demand-side
participation in the wholesale markets. As we implement the meters and tariffs that will allow selected
customers to shed loads, we should remember that investors will be aware of the new flexibility on the
demand side of the markets. Investors will adjust their assessments of future profitability and postpone
investment in new power plants. Based on the simulated scenario shown here, investors would probably
continue to build in waves of boom and bust, and the wholesale market would remain exposed to periods of
low reserve margins and price spikes.
Appendix A. Closer Look at a Single Day

This appendix shows the “first day” screens of the Western Market Model. These allow for a closer look at the market operations for a typical day in the winter of 1998. Figure A-1 shows the first day results with the hydro generation button in view. It explains that hydro units are dispatched as “must-run” units and that their generation is shaped to provide around a third of the peak demand.

The generations from different technologies in Figure A-1 are shown in a stacked graph, with “other” generation as the second resource in the stack. Other capacity is dispatched as a “must-run” resource. The other capacity is a combination of three WSCC categories (geothermal, other and internal combustion). The WSCC reports over 18,000 MW with over 15,000 MW located in California. Part of the WSCC “other” is wind capacity, but this capacity is removed from the “other category” and dispatched separately (with a 33% capacity factor).

The third resource in the stack is nuclear. The WSCC reports over 9,000 MW of nuclear capacity, almost half in California. The nuclear units are dispatched as “must-run” units with a forced outage rate of 10%. The scheduled outage rate is 20% with the maintenance mainly in the spring.

Figure A-1. First Day Results with Hydro Information in View.
Figure A-2 shows the first day results with the coal button in view. It explains that coal-fired units are bid into the market at variable costs and that they would end up serving as the marginal resource during night time hours in a typical day in the winter of 1998.

Figure A-2. First Day with Coal Information in View.

Figure A-3 shows the first day results with the CC button in view. It explains that Combined Cycle Unit type are bid into the market at variable costs. The variable cost is the sum of O&M and fuel costs. The O&M is set at $7 per MWh and the total fuel cost, which range from 0.75 to $1.25 per MWh and on the fuel rates, which range from 9,000 to 12,000 bbl/wh. As an example, an individual coal unit might operate at 10,000 bbl/wh and pay $1 per MWh for coal. Its load factor would be 10 $/MWh, and its total variable cost would be 17 $/MWh.

The brown curve shows the minimum generation from coal (and all previous units). We may compare the brown curve with the demand to learn if coal plants are on the margin. The comparison shows that coal plants would be the marginal resource during the night time hours in a typical day in the winter of 1998.

Figure A-3. First Day with CC Information in View.
Figure A-3 shows a different screen with the higher cost resources in view. The information button for the CCs is in view. CCs provide a small portion of the generation in 1998, and they appear on the margin for an hour or two for a typical day in the winter.

**Figure A-4. First Day with Information on the Regular Gas Steam Capacity in View**

**Figure A-5. First Day with Information on the Strategic Capacity in View.**
Figure A-4 shows the high cost resources with the gas steam button in view. The “regular” gas steam units are bid into the market at variable costs, and they would appear on the margin for around half the hours in a typical day in the winter of 1998.

CTs are next in the stack. These are single cycle combustion turbines. The WSCC data showed around 9,000 MW of CT capacity, with over 70% in the Northwest and in California. These units are used infrequently, so the model assumes that their forced outage rate and their scheduled outage rate may be set to zero. The model assumes that the CTs are bid into the spot market at variable costs. The variable cost is the sum of O&M and fuel costs. The O&M is set to $3 per mwh. The fuel cost depends on gas prices, which vary over time and across the region. Heat rates vary from around 9,000 to 18,000 BTU/kwh. If a California CT operating at 18,000 BTU/kwh were to pay $3 per MMbtu for gas, its fuel cost would be 54 $/mwh, and its total variable cost would be 57 $/mwh in the first day. Figure A-5 shows that CTs would not appear on the margin in a typical day in winter of 1998.

The final resource in the stack is “strategic capacity.” Figure A-5 shows the information on strategic units, gas-fired units which have been designated for economic withholding. Useful information on economic withholding appears in Figure 32 of the California ISO August 10, 2000 Report on California Energy Market: Issues and Performance May-June 2000. The report describes market prices with “competitive outcomes” (usually with total supply in excess of 140% of demand), with “non-competitive” outcomes (with no absolute shortages) and with shortages. The Western Market Model assumes that economic withholding begins when the reserve margin falls below 40% and that a larger and larger fraction of the “strategic capacity” will be withheld as the reserve margin declines toward alert levels. When the reserve margin hits 7%, for example, all of the “strategic capacity” is subject to economic withholding.

Figure A-5 shows no strategic generation for the typical day in the winter of 1998. As demand grows, however, strategic generation will play a larger role. For example, strategic generation is simulated to be especially important in explaining the high prices observed in 2000 and 2001. Further details are given in Appendix B.

Appendix B. Simulated Prices and Actual Prices

This appendix provides a comparison of simulated wholesale prices with actual prices reported by the California ISO. The time axis is expanded to allow a closer look at prices in the first four years. The buttons are located next to the results for each quarter. The ISO information on actual prices is shown in black. The ISO calculates counterfactual prices that would appear if California markets had cleared in a competitive manner. The counterfactual prices are shown in blue. The button for Spring of 2000 is open in Figure B-1. It summarizes the ISO information for April, May and June of 2000. The average price over these months was 78.7 $/mwh. The counterfactual price over these months was 47.3 $/mwh.

The simulated prices from the Western Market Model are shown in red. The average quarterly prices are relatively constant during the first two years and increase dramatically during 2000 and 2001. Figure 3 notes that the first price spike appears in the spring of 2000. This spike contributes to the higher prices for spring of 2000. But Figure B-1 shows that the model falls short of the benchmark. The simulated price is 56 $/mwh, which is around 30% below the actual price reported by the ISO.
Figure B-1. Comparing Simulated Prices with Actual Prices (Spring 2000 Button Open).

Figure B-2 shows that the model does much better in the summer of 2000. The simulated price (shown in red) is 130 $/mwh which is quite close to the ISO benchmark of 132 $/mwh. The model results are somewhat high in the fall of 2000. The simulation shows the western market clearing at 240 $/mwh, but the ISO reports California markets at 216 $/mwh. The model is somewhat high in the winter of 2001 as well. It shows 251 $/mwh while the ISO reports 213 $/mwh. By spring of 2001, the market is back on target. It gives 163 $/mwh versus 159 $/mwh reported by the ISO. An ISO benchmark for September of 2001 was not available when this display was created. But I did have results for July (63 $/mwh) and August (46 $/mwh). If September prices were similar to August, the average for the summer of 2001 would be 52 $/mwh. The simulation result is 54 $/mwh for the summer of 2001.

Figure B-2. Comparing Simulated Prices with Actual Prices (Summer 2000 Button Open).
Figure B-3 shows the historical results displayed on the main screen if the user sets the fraction of gas steam capacity for economic withholding to zero. This change allows the model to simulate competitive market prices in the WSCC system. The market prices are displayed in the same format as Figure 3. Recall from Figure 3 that the first price spike appeared in the spring of 2000, peaking at nearly 200 $/mwh. The button in Figure B-3 draws our attention to a similar price spike in the new simulation. We learn that price spikes could still appear with competitive assumptions, but they would not be as severe.

Figure B-3. Main Screen with four Years of Simulated Prices if there is no economic withholding.

Figure B-4 shows the price checks screen with simulated prices arranged for comparison with the ISO counterfactual prices. As before, the model results are shown in red. But in this case, we compare the model results with the ISO counterfactual prices shown in blue. The spring 2000 button is open, so we can read that the ISO benchmark was 47.3 $/mwh. The simulation result comes quite close at 46.5 $/mwh. The simulation result is somewhat higher than the ISO counterfactual result in summer of 2000 (106 versus 91 $/mwh) and in the fall of 2000 (182 versus 161 $/mwh). I did not have ISO counterfactual results in 2001 when this display was created, so the blue curve drops to zero at the end of the year 2000.
Appendix C. The Size of the Current Building Boom

Figure 7 shows a business as usual scenario in which CCs under construction peaks near the end of 2001. The current building boom leads installed CC capacity to grow to around 27,000 MW by the start of 2004. The scenario shows a two-year lull in construction followed by a second wave of construction. By the end of the simulation, there is 43,000 MW of installed CC capacity in the WSCC.

This pattern of boom and bust construction arises from the theory of investor behavior shown Figure 6 and implemented in Figure C-1. This screen shows the attributes of new CCs with a total levelized cost around 31 $/mwh near the start of the simulation. The CCs require 12 months for permitting and 24 months for construction. The equations for developers’ permits builds the paperwork toward the 45,000 MW target shown in Figure 7. The permits are distributed among the four areas of the WSCC based on the distribution of power plant construction in a recent review. Investors look into the future to anticipate the growth in demand, the amount of generating capacity and the system reserve margin. From this information, they estimate the average market price over the course of the year shortly after a new CC would enter operation. The investors watch current generating capacity. As soon as units are retired, they adjust their forecast downward. (They do not try to guess when future retirements might occur.)

This appendix focuses on the weight given to capacity in the pipeline. The "weight" in Figure C-1 represents how the investors account for the CCs under construction in forming their estimates of future market prices. We set the weight to 1 if we believe that all of the investors count the CCs in their forecasts while they are still under construction. We set the weight to 0 if we think none of the investors count these units in their forecasting. The evidence from industries like commercial real estate suggests that investors are not inclined to count all of the capacity in the construction pipeline in their decision-making. Figure C-1 shows the base case assumption at 0.5, an intermediate value which gives results similar to the dominant pattern published previously (Ford 2001).
Figure C-1. User Inputs for New Combined Cycle Power Plants.

Figure C-2. Comparison of CCs Under Construction with in Three Simulations.

Figure C-2 compares the CCs under construction in three simulations with different weights assigned to the CCs under construction. With the weight set to 0, we see a more prolonged building boom which does not crest until the end of 2002. CC capacity would grow to around 51,000 GW by the end of this building boom. This huge building boom would build reserve margins to well above 15% for the
simulation. Figure C-2 shows that this simulation generates construction activity slightly higher than the historical benchmarks. The results with the weight at 0.5 have been shown previously. This is the business as usual scenario reported in Figure 7. Figure C-2 shows that the base case provides a somewhat better fit with the historical benchmarks. CC capacity would grow to around 27,000 MW by the end of the first building boom.

The third simulation shows the pattern of construction if investors counted 100% of the CCs under construction in their decision-making. This assumption leads to a smaller boom, one that falls well short of the historical benchmarks at the end of 2000 and midway in 2001. If we believed a weight of 1.0 were realistic, however, we would expect to see investors adjust their construction shortly after the first building boom and arrive at a dynamic equilibrium with a relatively constant amount of construction activity year after year. This level of construction turns out to be insufficient to deliver a reliable system. Reserve margins (shown on a different screen) would trigger alerts from 2005 until the end of the simulation. Price spikes (shown on another screen) would appear by the year 2005 and remain for the rest of the simulation. These results are similar to patterns published previously (Ford 2001).

Appendix D. The Demand for Gas for Power Generation

The dramatic increases in natural gas prices is one of the factors contributing to the unusually high prices in the western electricity markets in the year 2000. The natural gas system has been examined in recent studies by the State of California (CEC2001) and the State of Washington (WA OTED 2001). These studies remind us of the important linkages between the natural gas supply and the competitive electricity markets.

The Western Market Model accepts user inputs for gas prices in each of the four WSCC areas as user inputs. The simulations shown in this report set the long-term price of gas at 4 $/mmBTU in California. (According to an August 17, 2001 article in the San Jose Mercury News, this value is in the middle of a range of values used by officials at the Pacific Gas and Electric Company.) The price of gas in the rest of the WSCC is set at 3 $/mmBTU. These prices are fixed, regardless of the amount of gas that is consumed in the power sector. This appendix reports the amount of gas that would be consumed in power generation in the WSCC. The gas consumption patterns will provide some context for evaluating the assumption that gas prices will remain constant in the coming years.

Gas consumption is based on gas-fired generation (see Appendix A) and the average heat rates of the units that are in operation. Figure D-1 shows the gas consumption as the model simulates a typical day in each quarter. The hour by hour consumption is shown in gray on a scale from 0 to 8 MMcf per hour. The results for each 24 hour day are accumulated and then reported for the quarter on a scale from 0 to 8 Bcf per day. The most dramatic result in Figure D-1 is the huge increase in gas consumption during the summer of 2000. Many believe that this increase contributed to the tight supply conditions in the year 2000 and is one of the reasons for the sharp increase in gas prices in the year 2000.
The blue curve in Figure D-2 shows the total gas consumption for each quarter reported in Bcf per year. The State of Washington (WA OTED 2001) reports gas consumption in the west at 1,198 BCF for 1999 and at 1,761 BCF for 2000. The model results for 1999 are 2% below the WA OTED estimate; the results for 2000 are 2% high.

The red curve in Figure D-2 shows the gas consumption from the CCs in the same units and on the same scale. The construction boom leads to a major increase in installed CC capacity in the years 2002 and 2003. Figure D-2 shows that the gas consumption from these new units would increase dramatically during the years 2002 and 2003. But total gas consumption is shown to decline during this time period. These are the “bust years” in the boom/bust cycle shown in Figure 8. The system operator is able to meet...
electricity demands without accepting the bids of the older, less efficient gas-burning units. Older units would not be operated as extensively during these years, and total gas demand remains relatively flat for three or four years. After 2004, the total demand begins to grow again. We know from Figure 7 that installed CC capacity is constant at this time, so the growth in gas demand is coming from greater operation of the older, less efficient gas-burning units.

Figure D-3 compares the quarterly gas demands in two simulations. The base case simulation is shown in blue. The alternative case assumes a much more vigorous building boom (described in the previous appendix). The investors are assumed to discount CCs currently under construction, and the current building boom does not crest until the year 2003. Figure D-3 shows that a more exuberant building boom would actually lead to lower consumption of gas in the western electric system. The reduction in gas consumption arises from the reduction in market clearing prices that appear in the simulation with a larger building boom. Lower market prices lead to lower operation of the region’s older, less efficient gas-burning units.

![Figure D-3. Comparison of Gas Consumption for Power Generation in Two Simulations.](image-url)
References


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