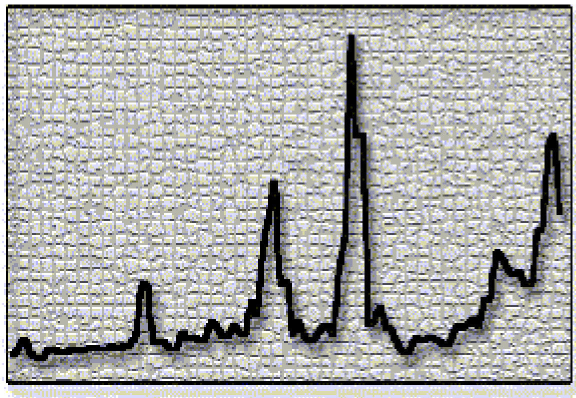
Study of Western Power Market Prices
Summer 2000



Final Report
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Northwest Power Planning Council document 2000-18

Executive Summary

Introduction

Almost two years ago, the Council initiated a study of the adequacy of the Northwest's power supply. This study was motivated by the observation that while the region had enjoyed several years of robust economic growth and, consequently growth in the demand for electricity, there had been very little in the way of new generation development. At the same time, efforts to improve the efficiency of electricity use in the region had been reduced dramatically because of the uncertainty of utility restructuring. This raised the concern that under conditions of high stress, the system might not be able to fully meet the region's power needs to serve load and to maintain the reserves essential to a reliable system. Conditions of high stress involve combinations of high weather-driven loads, poor hydropower conditions, and forced outages of thermal and hydropower generating units,

The study was completed late last winter.[1] It concluded that:

- ♦ There is an increasing possibility of power supply problems over each of the next few winters (December, January, February), reaching a probability of 24 percent by 2003. This takes into account both regional resources and the availability of imports. The level and duration of the possible shortfalls could be relatively small – a few hundred megawatts for a few hours – or quite large – a few thousand megawatts for extended periods.

[1] Northwest Power Supply Adequacy/Reliability Study, Phase 1 Report, Paper 2000-4, Northwest Power Planning Council, March 6, 2000.

- The region would need the *equivalent* of 3,000 megawatts of new capacity to reduce the probability to a more acceptable 5-percent level. That new capacity should take the form of new generation ***and*** economic load management, i.e., reductions or shifts in consumer loads that make economic sense for the consumer and the power system.
- It was unlikely that market prices would be sufficient to stimulate the development of sufficient new generation in that time frame. This meant that in the near-term, an even higher priority needed to be placed on developing economic load management opportunities.

While this study generated a good deal of interest, it has been difficult for people to get too concerned about probabilities generated by arcane computer models. This summer, however, developments in the power system have captured the attention of the industry and the public. Those developments resulted in unprecedentedly high prices in Western power markets, including the Northwest. Average prices for power traded for the heavy load hours of June 28th at the Mid-Columbia trading hub reached almost $700 per megawatt-hour (MWhr). This is more than 10 times the previous high and is consistent with the prices seen at other trading hubs in the West. Moreover, even for off-peak periods and days for which prices were not at extreme levels, they were considerably higher than past summers.

These prices have caused some economic hardship in the Northwest. The hardships have been limited by the fact that spot market purchases represent a small portion of the total amount of power consumed in Northwest. Relatively few retail customers purchase directly from the market or are on market-indexed rates. However, several industrial customers who are on such rates found it uneconomical to continue operation at these power rates. In addition, several utilities are seeking increases in their retail rates to cover the increased cost of power purchases. Because of these impacts, Governors Locke of Washington and Racicot of Montana asked the Council to undertake a study to explain the reasons for the prices seen on the market and the actions that might be taken to mitigate these prices.

The Council believes that the market prices seen this summer are a tangible manifestation of the fundamental problems identified in the Council's power supply adequacy study of last winter. That is, the prices are an indicator of approaching scarcity. This summer, the system, which already is facing tight supplies, has been further stressed by combinations of unusually high loads, poor hydropower conditions, and forced outages of thermal units. There is little in the way of price-responsiveness in demand to mitigate these prices. Those who had available supply were able to ask for and receive high prices. This combination of factors is precisely what leads to the power supply adequacy problems identified in the Council's earlier study. These factors apply not only to the Northwest but also to the entire Western Interconnected System. There were some additional factors acting this summer related to the design of the California market, but they should not obscure the basic underlying problem. Absent some action, the next similar event could result in not only high prices but also a failure of the system to meet loads.

In the following paragraphs we will summarize the evidence regarding the factors affecting Western market prices this summer, focusing in some detail on the last week in June, the period in which the highest prices were observed. We will then offer some recommendations for actions to mitigate future price excursions and potential power supply adequacy problems.

What Caused this Summer's Prices?

As noted above, we believe the prices experienced this summer are symptomatic of an overall tightening of supply, exacerbated by a number of factors. Some of these factors are physical and economic, others are related to the relative immaturity of the competitive electricity market and the uncertainties involved in the transition from a regulated structure. The physical and economic factors include:

- unusually high weather-driven demands throughout the West,
- an unusual pattern of hydropower generation,
- a high level of planned and forced outages of thermal generating units, and
- high gas prices.

The factors related to market immaturity and transitional uncertainties include:

- the lack of a demand-side price response in the market;
- inadequate utilization of risk mitigation strategies, and
- factors related to the design and operation of the California market.

Overall Tightening of Supplies

Between 1995 and 1999, WSCC peak loads increased by nearly 12,000 megawatts, or by about 10 percent. The increase would have been even more if 1999 hadn't been a relatively mild weather year. Generating capacity available during peak load months did not increase to keep pace with peak load growth. While peak loads increased by 12,000 megawatts from 1995 to 1999, generating capacity only increased by 4,600 megawatts.

We also believe that efforts to improve the efficiency of electricity use, i.e., conservation, have fallen off considerably in recent years. This is largely the result of the uncertainty created by the restructuring of the electricity industry. Utilities, who were the primary vehicle for conservation development, generally reduced their efforts because of concerns about creating potentially stranded investment if retail access resulted in the loss of customers. There were also concerns about the need to raise rates to cover conservation costs and the revenues lost as a result of conservation.

The effect of growth in demand outstripping the growth in resources is a narrowing of reserve margins. This implies more efficient utilization of existing capacity and was an anticipated benefit of moving to a competitive generation market. However, when it proceeds to the point of putting reliability at risk and destabilizing prices, it is a problem.

Physical and Economic Factors

High Peak Loads

The period of the highest prices coincided with a period in which loads in the Northwest, California and the Desert Southwest were at high levels as a result of high temperatures throughout the West. In the Northwest, peak loads were approximately 3,400 MW greater than last year while in California on the same day loads were approximately 1,400 megawatts higher. [California and the U.S. portion of Northwest Power Pool (NWPP) combined, increased 4,826 MW from the peak on June 30, 1999 to the peak on June 28, 2000, both Wednesdays.]

Unusual Hydropower Production

While the summer of 2000 was expected to be a more or less normal year in terms of overall runoff in the Northwest, the runoff came in an unusual pattern. Runoff in the early spring was somewhat higher than usual. But in May and particularly in June, the runoff and hydropower generation was less than normal and much less than 1999. Hydropower generation in late June was approximately 6,000 megawatts less than the same time in the previous year.

Planned and Forced Outages of Thermal Units

Maintenance on thermal generation is frequently planned for the May-June period when abundant hydropower is typically available. In addition, plants do break down, sometimes when it is least desirable to do so. We have attempted to identify Northwest thermal units that were either on planned or forced outage status during the last week of June. This was done by examining the generation data reported to the Western Systems Coordinating Council or supplemental data that was provided by Northwest generators. These combined data sets comprise about 85 percent of the capacity in the Northwest. From these data it appears that approximately 1,670 MW of capacity was out on a long term basis, either planned or extended forced outages, and another 3,400 and 2,700 MW experienced short-term forced outages on the 27th and 28th respectively. Total generation, thermal and hydro, for the last week of June was approximately 4,000 MW below the levels of 1999.

Load/Resource Balance for the Northwest

A preliminary analysis of loads and resources for the Northwest Power Pool - US Systems for June 28, the peak price day of June, indicates a peak net hourly load (native load plus exports) of about 41,000 MW. We were unable to identify more than 38,000 MW of capacity, including imports, available to meet these loads. This analysis has a high level of uncertainty (hourly operating data was available for about 85 percent of installed capacity and the output of the remaining installed capacity had to be estimated and data errors are possible). Obviously, since the lights did not go out, the system was able to balance loads and resources. It is likely that data errors and errors in our estimates for the non-reporting generators are at fault. Nonetheless, the evidence strongly suggests that the Northwest was operating under near-deficit conditions during the heavy-load hours of that day.

Gas Prices

Between the summer of 1998 and the summer of 2000 natural gas prices at Sumas (on the Washington-British Columbia border) increased from about $1.50 per million Btu to $3.30. Prices into Southern California increased over the same period from about $2.40 to $4.18. Prices have moved substantially higher during late August and September. During mid- September, prices at Sumas were $4.60 and prices into Southern California were over $6.00, although the California prices were affected by a serious pipeline explosion.

Higher natural gas prices, should they persist, will result in higher "normal" prices of electricity. Depending on the generating technology used, a $2 dollar increase in natural gas prices (roughly consistent with the doubling of gas prices seen by mid-summer) could increase electricity prices by between $15 per megawatt-hour and $22 per megawatt-hour. Average electricity prices during high load hours in the Pacific Northwest mid-Columbia market increased by $140 per megawatt-hour between June 1999 and June 2000, and light load hour prices increased by $46. The comparable price increases in Southern California were $113 and $28. The increase in natural gas prices can not come close to explaining the observed increase in electricity prices.

Factors Related the Immaturity of the Competitive Electricity Market and the Uncertainties in the Transition from a Regulated Structure

Lack of Price Responsive Demand

A systemic problem associated with the immaturity of the competitive electricity market is the lack of a demand side to that market. Price responsive demand is important to an efficiently operating competitive market. Price responsiveness is an essential mechanism to balancing supply and demand. Without some degree of demand responsiveness, there is no check on the prices that can be charged when supplies are tight, except for artificial caps. This is particularly critical when supplies are stretched to their limits. Under those circumstances, a relatively small degree of price responsiveness can have a relatively large reducing effect on prices, and could also mean the difference between maintaining service and curtailments.

Currently, at any given hour, the amount of electricity demand is virtually independent of wholesale price. This is because the vast majority of electricity consumers do not see market prices in anything approaching real time and, for the most part, have done little if any thinking about how they could reduce their demands if power were very expensive. The Council is not advocating retail access as means of achieving price responsiveness. The states are making their decisions about when and how much to open their retail markets to competition. But developing price responsive demand does not require passing real-time market prices on to all consumers. It does mean, however, that those the suppliers who do see wholesale prices should act as intermediaries between the market and consumers to effect load reduction or shifting that is in the mutual economic interest of the consumer and the power system. We believe this will develop in time and that the current high prices will help motivate that development. However, given the tight supplies and high prices now affecting the market, the Council believes that special effort should be devoted to encouraging and facilitating the expedited development of the demand side of the market now.

The California Effect

Among the Western States, California's electricity industry is farthest down the restructuring path. Their path is, in many ways, quite different than most other examples. They have created a market structure that is quite centralized and quite complex. For most of its three-year life, the California market demonstrated competitive power prices. However, under periods of stress, we believe there are characteristics of the California market structure and the incentives it creates that arguably result in prices that are higher than they might otherwise be. The California Independent System Operator (ISO) and experts acting in an advisory capacity to the ISO have identified these characteristics. These include restrictions on the ability of California utilities to enter into longer-term contracts, thus forcing most loads into day-ahead and hour-ahead spot markets operated by the California Power Exchange. Other facets of the market design create incentives that, when supplies are tight, result in as much as 20 percent of the load being met in a real-time market operated by the ISO. This is not a situation conducive to moderating price spikes. We know California is studying these issues and we are hopeful that they will resolve them in a satisfactory fashion.

Did Market Participants Manipulate the Market?

Much is made of market participants exercising market power during this summer's price spikes. Clearly the prices we have seen are well above a "competitive" price, if that is defined as the operating cost of the most expensive unit on the system that must run to meet load. The ability of market participants to ask for and receive more than the competitive price can be defined as market power. However, this is also the normal functioning of a market when supplies are tight and there is no moderating effect of price responsiveness. It is neither illegal or immoral.

The Council did examine the generating records of most Northwest power plants to see if there was evidence of manipulating the market by "withholding," i.e., holding power off the market to drive up prices. We found no clear evidence of such behavior. Power plants were generally being operated as one would expect given the characteristics of the plants. Hydro plants were typically following load. Thermal plants were typically running "flat out" or, in the case of units with higher operating costs, backed down during the off-peak periods. Where there were operating patterns that might be interpreted as withholding, the quantities involved were too small to affect the market.

The Council did not have access to information that would permit analysis of the bidding strategies of different market participants. We do not know whether that information would suggest market manipulation.

Recommendations

Encourage the Greater Use of Risk Mitigation Mechanisms

One of the characteristics of a commodity market is the emergence of mechanisms to manage risk, and electricity is rapidly becoming a commodity market. These mechanisms include actual physical longer-term contracts for supply, futures contracts, financial hedging mechanisms, and so on. These mechanisms can limit exposure to high prices. At the same time, however, there is always the risk that they will prove more costly than the spot market. Risk mitigation comes at a cost, and it is not realistic to be fully hedged for all risk. But the experience of this summer suggests there could be greater use of risk management tools.

As noted earlier, we believe the limitations on forward contracting by California utilities was a contributing factor to the price extremes of this summer. We believe the same is true of other market participants in the Northwest and elsewhere. While opportunities to enter into forward contracts and other hedging arrangements have existed, it may be that the protracted period of low market prices for electricity lulled some market participants into believing they had no need of such mechanisms. Recognizing the commodity nature of the electricity market and taking appropriate steps to protect against the upside risk is important. Had more market participants done so, it is likely that this summer's price volatility and its impacts would have been moderated. Forward contracting is also a vehicle by which new entrants in the generation market can limit their downside risk, thereby facilitating the development of new generation.

Evaluate the Need and Options for Further Encouraging Generation Development

As noted earlier, the Council's analysis of power supply adequacy indicated that market prices would not be sufficient to support the development of "merchant" power plants, i.e., plants selling into the spot market exclusively, until 2004. The Council has also done analyses looking at actual market prices over the past year to see if prices had been sufficient for a new entrant to cover its variable operating costs and its fixed costs and earn a reasonable rate of return. Until this summer the answer has been "no."

With the electricity and gas prices experienced over the past year, the answer has become "yes." With the higher prices, a couple of plants not considered in the Council's adequacy study have begun construction. In the Northwest, there are now 1,276 MW of capacity under construction that should come on line in 2001 through 2002. There are another 2,977 MW that already have site certificates, 1,291 MW of which we judge to be "active" projects, and another 3,060 megawatts that are in or have begun the siting process. The siting process does not appear to be a problem in that there is a backlog of sites that have been permitted and many more in the process. Almost all of these are natural-gas-fired combustion turbines, and nearly all of them are located within reasonable proximity to natural gas pipelines and transmission lines. There is a similar story to be told elsewhere in the West.

The degree of developer activity is encouraging. However, if we were to experience a couple years of relatively warm, wet winters and cool summers with good hydro conditions, market prices would probably fall and many of the active projects might become inactive. If followed by a dry spell and a hot summer or a cold winter, we would be up against the supply limits again.

The question this possibility raises is whether we can rely on the market to provide sufficient capacity for reliability purposes. And if not, what are the options for assuring that there is capacity available to assure reliability and mitigate excessive price spikes? The Council intends to pursue this question.

Accelerate Efforts to Develop the Demand Side of the Market

While the lead time for the development of new combined cycle generation is relatively short, development will take some time. During that time, the region and the West are vulnerable to further price spikes and possible reliability problems. Moreover, it is not certain that the long-term market will support the level of development necessary to assure adequate reliability. Developing the demand side of the market has the potential for somewhat shorter lead times. Price-responsive demand can help mitigate price spikes and potentially avert reliability problems.

The Northwest has a great deal of successful experience in increasing the efficiency of electricity end-use as a resource. The region needs to reinvigorate those efforts in light of the market prices we are experiencing. There are cost-effective means of slowing the growth of demand that should be exploited. However, the region in particular needs to move aggressively to implement price-responsive demand management – reducing loads during periods of high prices or shifting the loads to periods of the day where prices are less. The bad news is that this region has relatively little experience with these approaches, although that is changing. The good news is that there should be significant untapped potential.

The Council believes that market-like mechanisms wherein the consumer receives a significant part of the benefit will be most effective. Pilot programs have been initiated this year in the region in which the serving utility and the load-reducing consumer share the cost savings of avoided power purchases (or the revenues from selling the freed-up power on the market). These programs appear to have been successful although limited in scope. The greatest potential for such partnerships probably exists within industry and large commercial buildings. What can be done will vary from building to building and process to process. Nevertheless, if provided the incentive, the Council believes people will rise to the challenge. Creating these incentives should be a priority for the utilities of the region.

California Should Correct the Incentives in their Market Structure that Contribute to Excessive Prices and Volatility

The Council believes that the California ISO and others in the California market have done a credible job of identifying the barriers and incentives created by their market structure that have contributed to excessive prices and price volatility. We know the issues are complex and politically volatile. We hope that the state can move quickly to correct these problems.

At Least Until the Market Matures, Data for Monitoring and Evaluating the Performance of the Market Should be Available on a Timely Basis

One thing that the experience of this summer has shown is that it is difficult to obtain the data necessary to monitor and evaluate the performance of the market. Despite the fact that utilities in the Northwest were extremely cooperative, there was a delay of many weeks before the relevant data could be obtained. While the WSCC maintains a data base of generation and transmission loading data, not all generators report to the system and of those that do, the data link is not necessarily carefully maintained. Despite incompleteness data, the WSCC has chosen not to release the information to independent body like the Council, even when the Council agreed to keep the data confidential and to use the data in such a way that individual plants could not be identified. We understand the possible commercial sensitivity of some of this information. We believe, however, that there should be arrangements possible that both protect the commercial value of the information and make it possible for responsible independent parties to evaluate market performance on a timely basis. At least until the market has matured and the public has greater confidence in its operation, this should be a high priority for market participants and organizations like the Western Systems Coordinating Council, the California ISO and regional transmission organizations as they are formed.

Electricity Emergency Process and Procedures Need to be in Place

If we are correct is our assessment that the electricity market prices experienced this summer are a warning of approaching scarcity, then establishing the processes and procedures that would be used in the event of an actual supply emergency should be a priority. Until new generation comes on line and demand-side programs can be implemented, there is significant probability that our emergency readiness will be tested. Necessary elements include an inventory of the actions that could be taken, the trigger points for taking these actions, clear definition of roles and responsibilities, and a communications plan to inform the public. We are pleased that efforts to accomplish this are underway involving the Pacific Northwest Utilities Conference Committee, the Northwest Power Pool, Bonneville, the Council, the Northwest states and region's utilities.

1. Wholesale Power Prices in the Summer of 2000 and the Focus of this Analysis

Wholesale Prices

The source of concern motivating this analysis is indicated in Figures 1-1 and 1-2. These show heavy load hour (6 AM to 10 PM) and light load hour (10 PM to 6AM) power prices at the Mid-Columbia (Mid-C) trading hub for May, June, and July for the years 1996 through 2000. These prices represent the volume-weighted average prices for trades made for a given day for a block of power covering the designated period (heavy or light load hours). These prices are determined by a survey of traders carried out by Dow Jones. They are plotted on a logarithmic scale to allow some definition of the prices in the years preceding this one.

Two things are evident from this data. First, a year-to-year progression in the average prices for the periods as supply margins have tightened is apparent. However, through 1999, prices generally do not exceed what would be thought of as a "competitive" price, i.e., the cost of operating the most expensive generating units on the system. That price would be less than $100/MWHr for a very inefficient oil-fired simple-cycle turbine. The data through 1999 also demonstrate the seasonal depression of prices that typically occurs in the May-June time frame coinciding with the peak run-off in the hydropower system. However, what has captured attention is that this year average prices for both heavy load hours and light load hours are much higher and routinely exceed a competitive price with extreme peaks in the several hundreds of $/MWHR.

It should be noted that these market prices do not reflect the prices paid for the majority of the power consumed in the Northwest. The volume traded at Mid-C amounts to about 3 or 4 percent of the electricity consumed in the region. Most of that power is secured under longer-term contracts that have lower prices associated with them. At the margin, however, market prices are the prices paid by utilities trying to secure additional short-term resources to meet their loads. Market prices are also paid by some industrial customers who are either meeting some or all of their needs with spot market purchases or who are on a market-indexed rate. For several years, relying to greater or lesser degrees on spot market purchases has been an economic benefit to those who have done so. Market prices have typically been less than the fully allocated (fixed and operating) cost of the system. This year that is not the case. The immediate effect of these prices has been economic hardship for some of those industrial customers, some of whom have found it uneconomical to operate at those prices. A delayed effect will be felt in consumer rates and/or shareholder returns as utilities seek rate increases to cover their increased power purchase costs.

It is also clear that the Northwest is part of a broader West Coast market. Figure 1-3 shows the June heavy load hour prices at Mid-C for the years 1998, 1999 and 2000 along with roughly comparable prices for California.[2] Power is traded freely throughout the Western Interconnection. Market prices tend to track one another, differentiated by transmission costs and, when congestion occurs on relevant transmission paths, congestion premiums (the cost of dispatching more expensive generating plants). Generally this means that power prices in one part of the West will affect power prices in other areas of the West. When congestion occurs, prices in the different markets may

[2] These prices were derived from the day-ahead hourly unconstrained market clearing price bid into the California Power Exchange (Cal PX).

decouple. That is, lower-priced power in one region cannot get to another, requiring that higher cost resources be dispatched within the second region.

From Figure 1-3, it is clear that Mid-C and Cal PX prices track fairly closely, with the Cal PX prices typically being somewhat higher. In June, the Northwest typically has abundant hydropower available and sometimes cannot sell all that it would like to into the Cal PX because the interties are full or very close to it. This year, Mid-C prices in June were frequently as high or higher than those in the Cal PX. As will be discussed later, we believe that is largely the result of relatively poor hydropower conditions and planned and forced outages of thermal units. As a result, interties were frequently far from full.

Figure 1-1

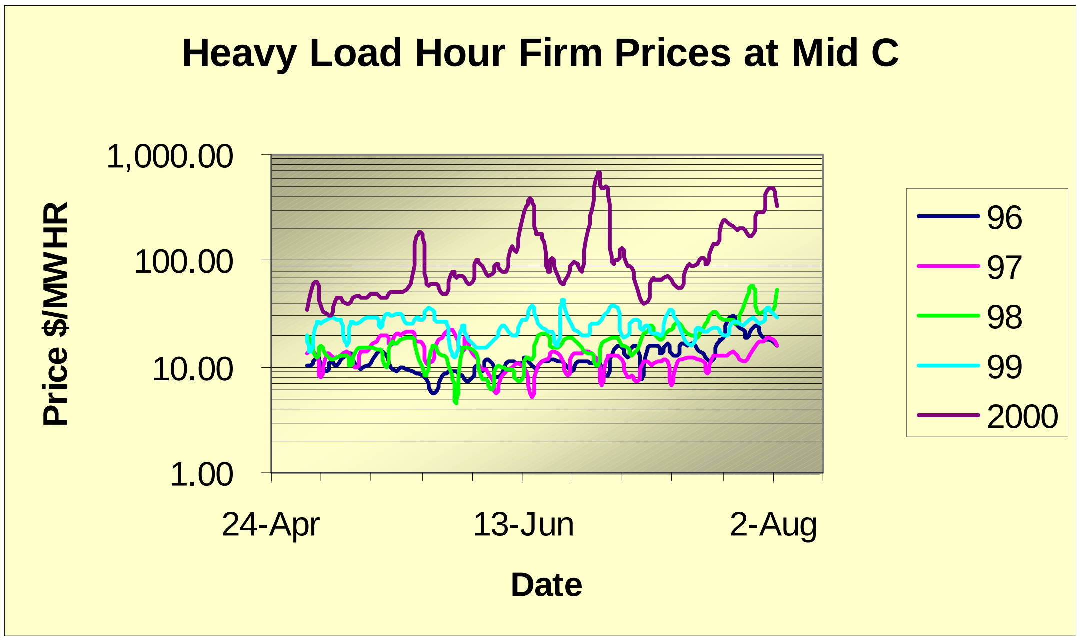


Figure 1-2

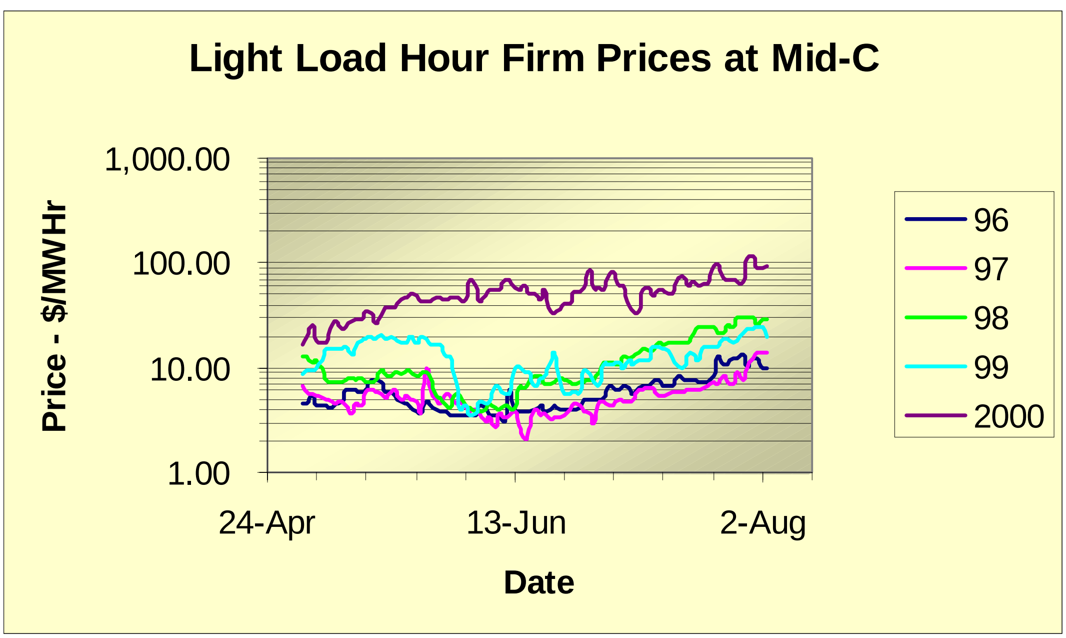
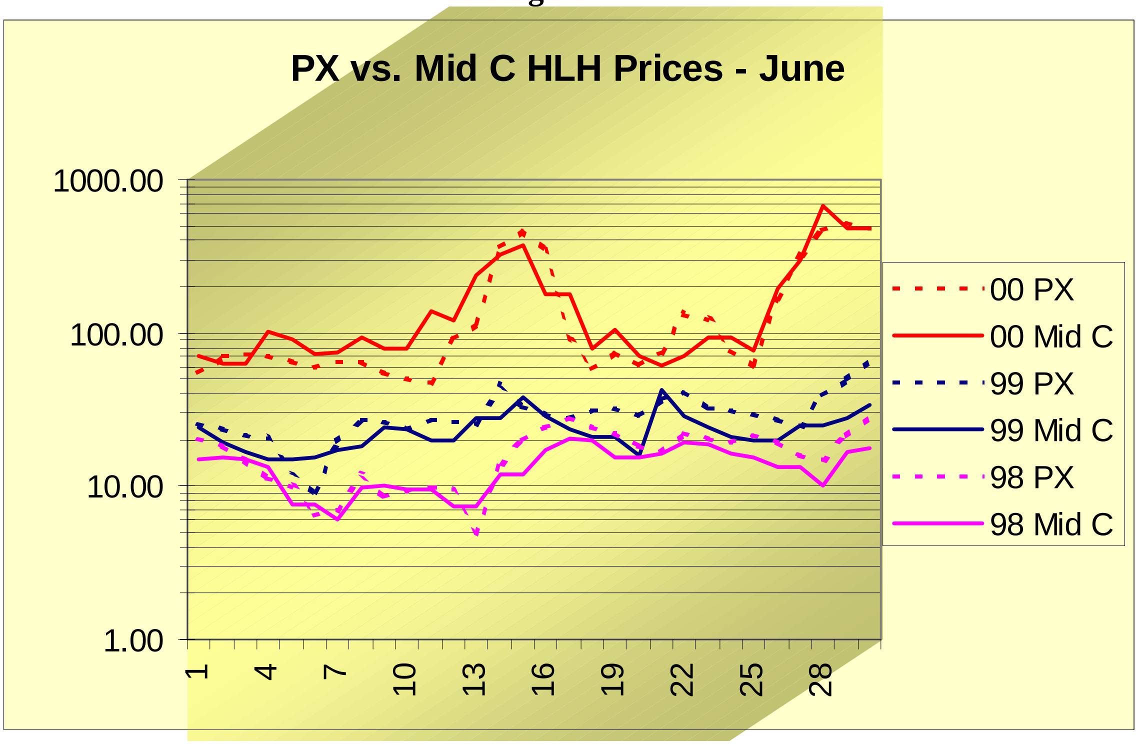


Figure 1-3



Focus of this Analysis

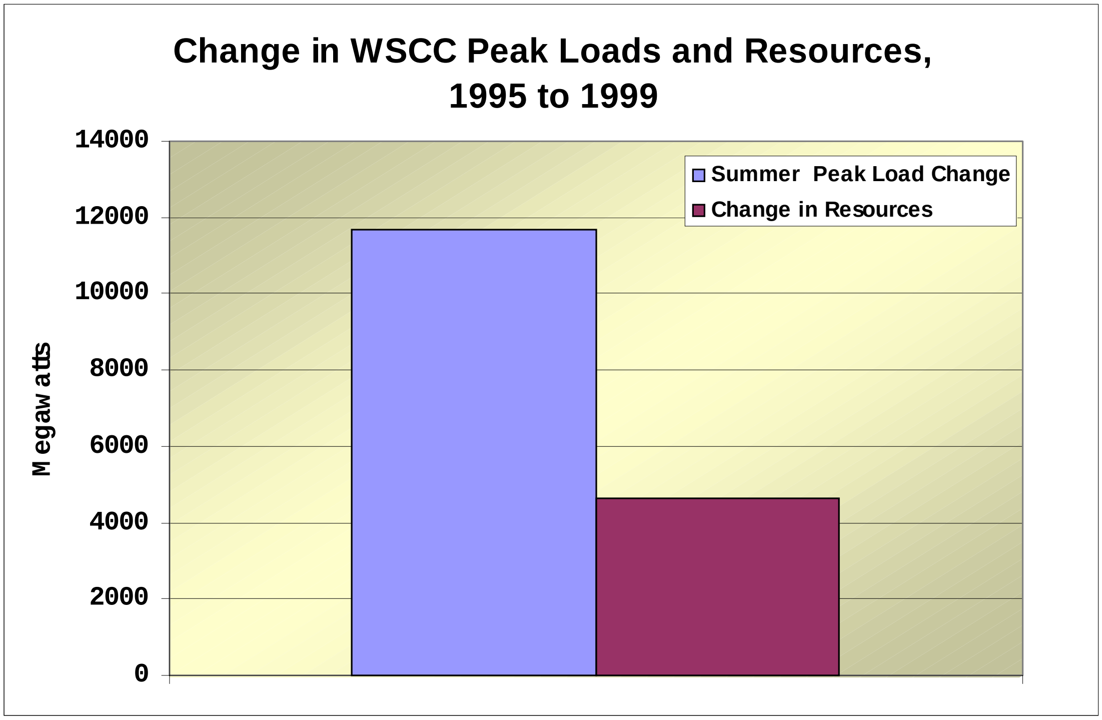
Although prices have been relatively high throughout the summer, the analysis focuses primarily on June 2000 and, in particular, the last week in June during which the highest Northwest on-peak prices were recorded. We believe the insights gained from consideration of that period generally are valid for other periods as well.

2. Evidence of Overall Tightening of Supplies

For the past several years, the economies of the West have been growing. This translates into growing electricity demand. Between 1995 and 1999, WSCC peak loads increased by nearly 12,000 megawatts, or by about 10 percent. Energy use during the same four years increased by about 65,000 gigawatt-hours, or about 2.3 percent annually. The increase would have been even more if 1999 hadn't been a relatively mild weather year.

Generating capacity available during peak load months did not increase to keep pace with peak load growth. While peak loads increased by 12,000 megawatts from 1995 to 1999, generating capacity only increased by 4,600 megawatts. Figure 2-1 illustrates the difference.

Figure 2-1

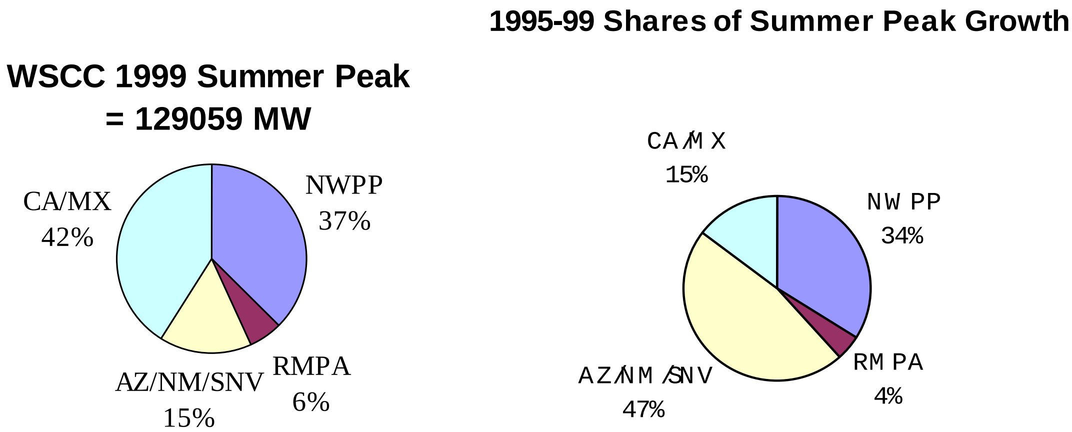


Although we do not have data to fully substantiate this, we also believe that efforts to improve the efficiency of electricity use, i.e., conservation, have fallen off considerably in recent years. This is largely the result of the uncertainty created by the restructuring of the electricity industry. Utilities that were the primary vehicle for conservation development generally reduced efforts because of concerns about creating potentially stranded investment in the event that retail access results in the loss of customers, and concerns about raising rates to cover conservation costs and lost revenues.

Loads did not grow evenly among the geographic areas of the West. The WSCC (Western Systems Coordinating Council) is divided into four subareas. The Northwest Power Pool (NWPP) is the largest area geographically and in terms of average energy loads. It includes the Council's region of Oregon, Washington, Idaho and Montana west of the Continental Divide, as well as Alberta and British Columbia in Canada, the rest of Montana, Utah, and substantial parts of Wyoming and Nevada. The NWPP is the only one of the four WSCC areas that has its peak loads in the winter. All of the other areas, and the WSCC as a total, have their peak loads in the summer. California and a small part of Mexico is the second largest energy load area, but is the largest summer peak load area. The other two areas are the Arizona, New Mexico, and Southern Nevada area (AZ/NM/SNV), and the Rocky Mountain area (RMPA) which includes Colorado and Eastern Wyoming. By far, the most rapid growth occurred in the AZ/NM/SNV area. Although this area only accounted for 12 percent of WSCC summer peak loads in 1995, it accounted for 47 percent of their growth from 1995 to 1999. Its loads increased by 38 percent over those four years.

Figure 2-2 shows the shares of 1999 summer peak loads and the shares of summer peak load growth by area from 1995 to 1999. Although the NWPP is a winter-peaking area, its summer peak loads grew substantially -- by approximately 3,900 MW. The net capacity additions in the NWPP area during that period were 1,374 MW. The ratio of peak load growth to net capacity additions for the NWPP is approximately the same as for the whole WSCC. Considering its size, California had a pretty small contribution to the summer peak load growth.

Figure 2-2

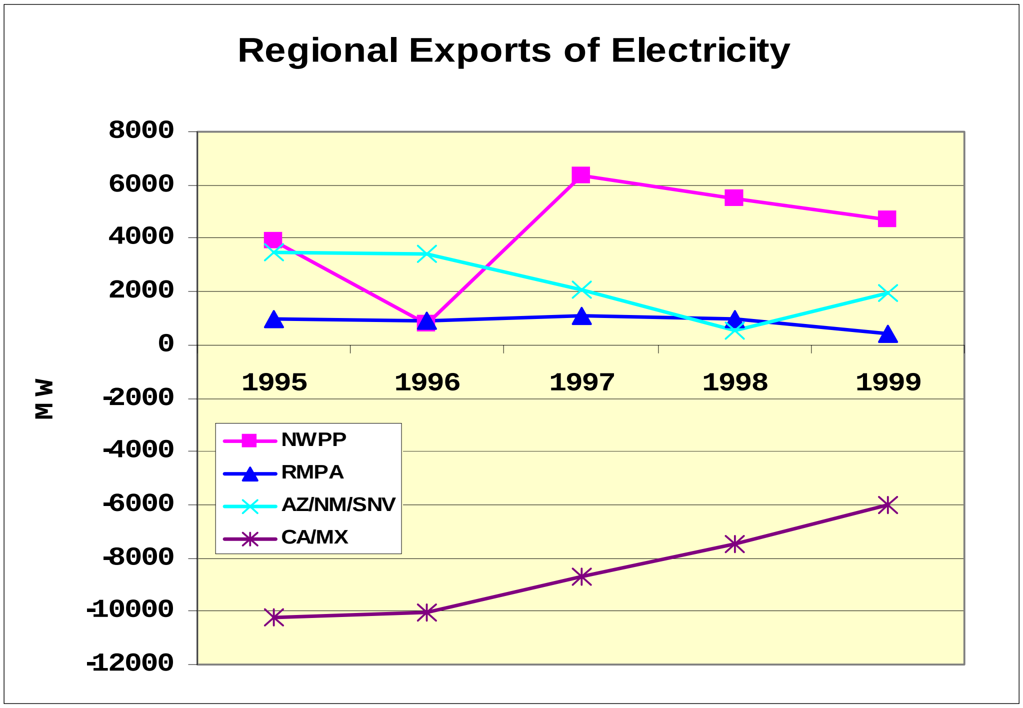


Growth outstripping demand inevitably means erosion of reserve margins, i.e., the amount of capacity available in excess of peak demand. This is not necessarily a bad development. A criticism of a regulated, vertically integrated utility system was that it resulted in over-investment in capacity. One of the anticipated benefits of a competitive generation market was the more efficient utilization of existing capacity and declining reserve margins. However, when reserve margins decline to the point where they threaten reliability and lead to highly volatile prices, many would say they have gone too far.

3. The Effect of High Coincident Peak Loads

To understand what has happened to electricity markets, it is also important to understand that in the summer California imports electricity from the other WSCC areas in order to meet its peak loads. Conversely, in the winter, the Northwest is frequently dependent on imports to meet its peak loads and energy requirements. Figure 3-1 shows net exports of electricity for each of the WSCC areas for the peak summer month. The negative values for California means that it is importing electricity. Note that the imports available from the NWPP are dependent on hydro conditions, but, in general, as loads have grown faster than generating capacity additions, decreasing amounts of electricity have been available to import into California.

Figure 3-1



When weather conditions are such that periods of high peak loads in exporting and importing regions coincide, the system is stressed more than is normally the case. During the summer of 2000, the resource squeeze in California has been increased by much warmer weather in California, the desert Southwest, and, at some times, in the Northwest as well. To illustrate this, we have plotted the June 1999 and 2000 loads for the California Independent System Operator (CAISO) and the U.S. systems of the Northwest Power Pool (Idaho, Oregon, Montana, Washington, most of Utah, and Northern Nevada). These are shown as Figures 3-2 and 3-3.

Figure 3-2

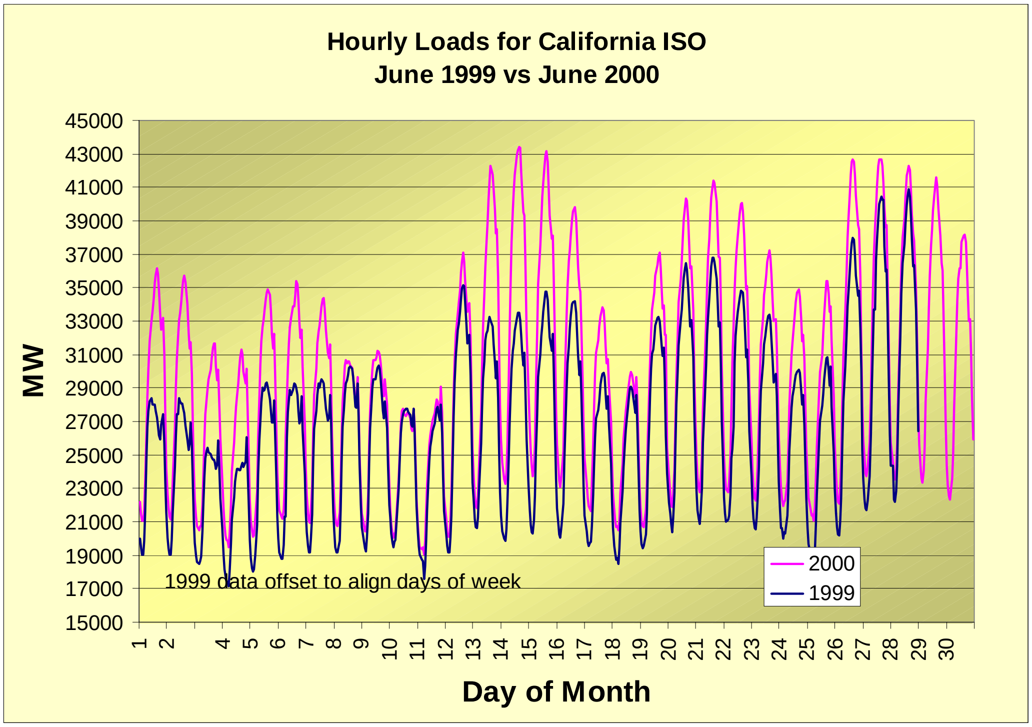
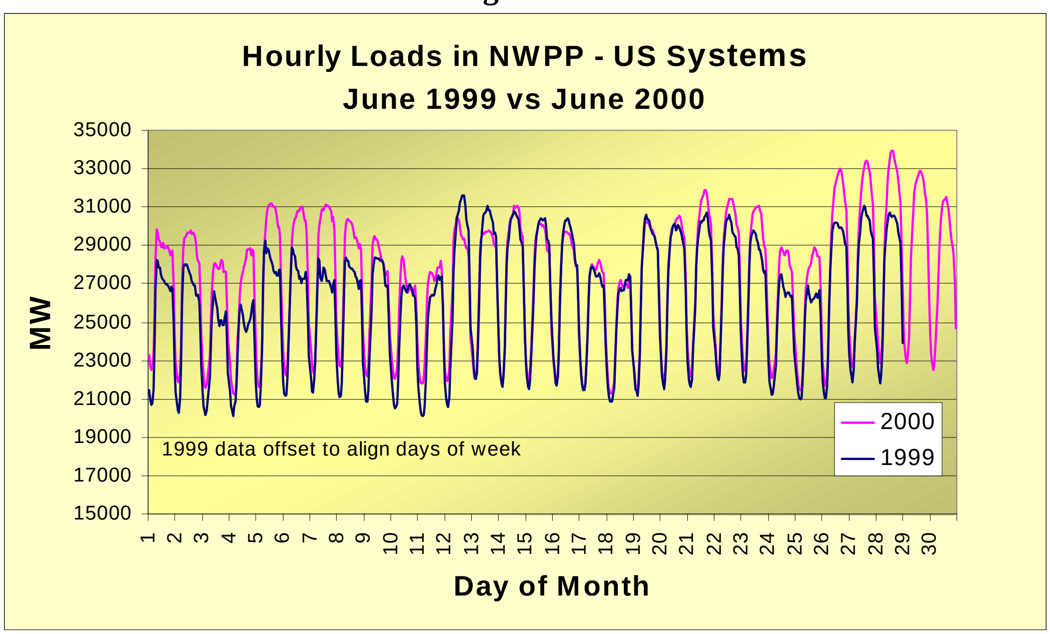


Figure 3-3



In order to understand these conditions, we have focused on three different weeks. The focus week for this analysis is June 22 to 28, 2000. For comparison, we look at a low-load week in June of 2000 and a high-load week in June of 1999. These are June 1 to 7, 2000, and June 24 to 30, 1999, respectively. These weeks run from Thursday to Wednesday, and we will particularly focus on the last day of each of these weeks. Figures 3-4A, B and C compare the hourly loads in California for the last day of each of the three weeks. These are presented side-by-side on the following page to permit easy comparison.

Figure 3-4A

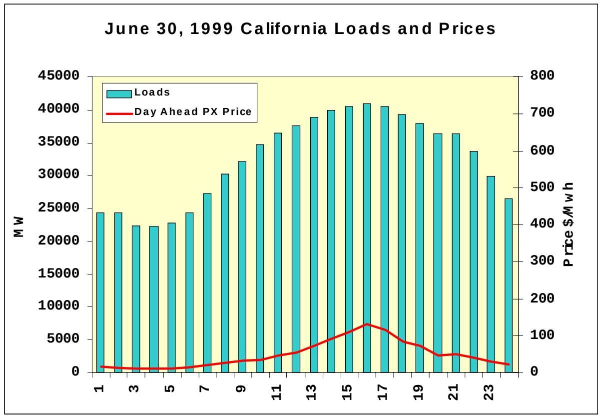


Figure 3-4B

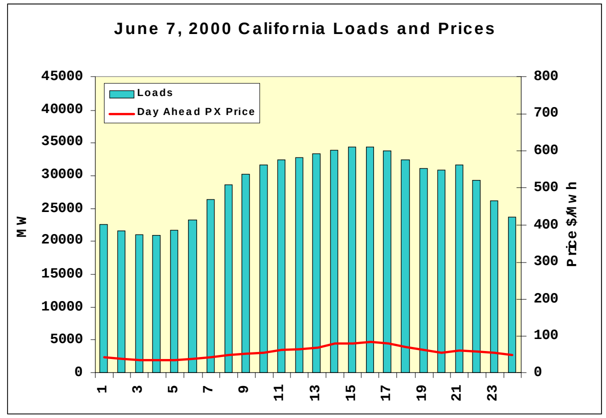
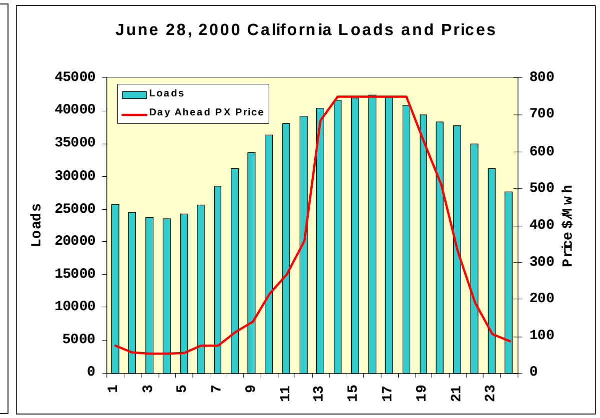


Figure 3-4C

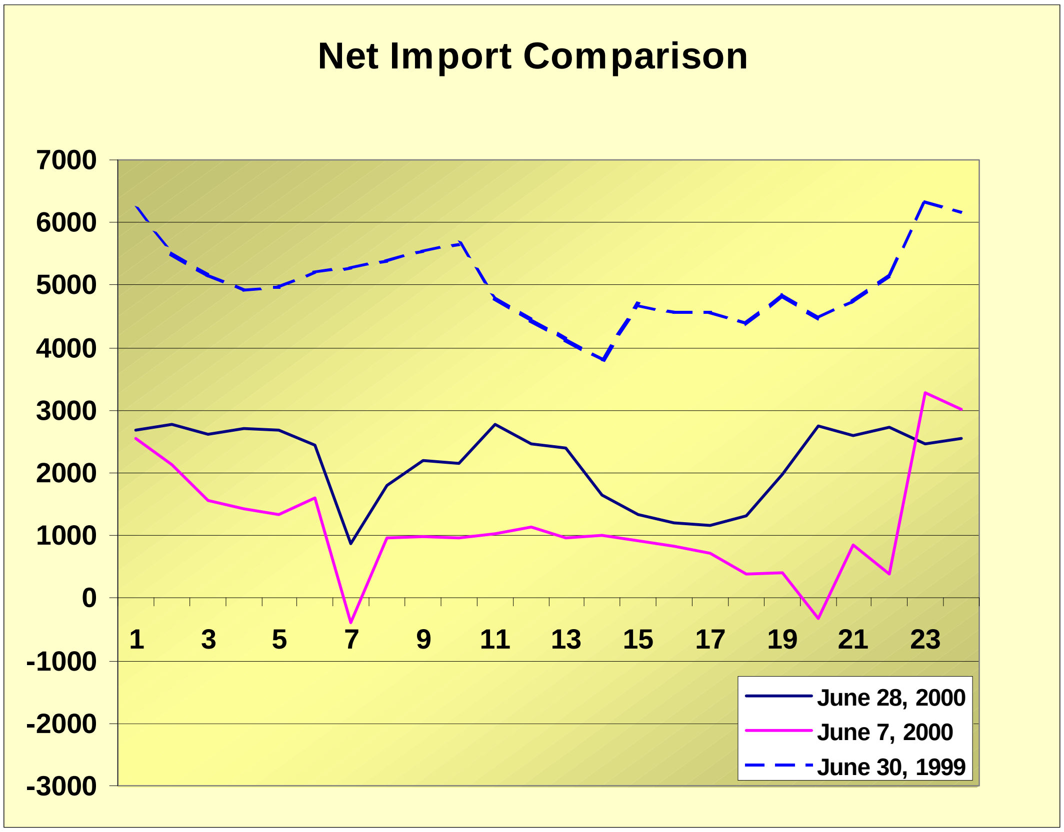


The loads in the last week of June 2000 were substantially higher than the loads in the other two weeks. However, on the last day of the weeks of late June 1999 and June 2000 the loads were comparably high, and about 7,000 to 8,000 megawatts higher than the loads on Wednesday, June 7, 2000. Figures 3-4A through C show each of these day's loads as bars measured on the left axis. They also show the day-ahead prices for that day plotted as a line and measured on the right axis. Although the loads are very similar for the two late-June Wednesdays, the price during peak hours in 2000, capped at $750 per megawatt-hour, was about six times the price in 1999. What accounts for such a dramatic change in a one-year span of time?

There are some supply and demand-related factors that made the electricity market tighter in 2000 even though the California loads were similar on June 28, 2000 and June 30, 1999. First, Northwest Power Pool loads were higher in 2000 by nearly 3,000 megawatts during the peak hours, as is clear in figure 3-3. Although we do not have the data to be sure, anecdotally, weather was hotter and loads higher in the desert Southwest as well.

Higher loads in the Northwest and desert Southwest, combined with less hydro electricity in the Northwest, decreased the imports available to help meet California loads. Figure 3-5 demonstrates that imports were far smaller into California in 2000 than they were in 1999. Making the situation even tighter were significant numbers of generating unit outages as is discussed in Section 5.

Figure 3-5

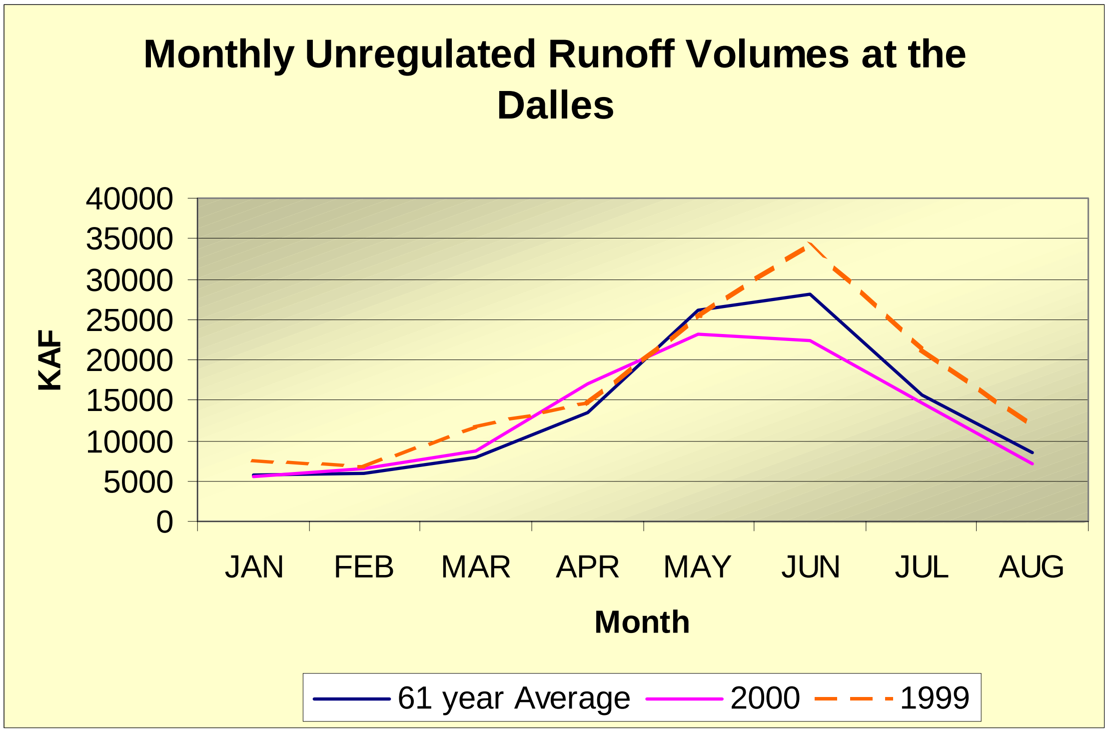


It seems likely that the tight supply/demand conditions bring out weaknesses in the California market structure that tend to worsen price volatility. This will be discussed in a later section.

4. Unusual Hydropower Conditions

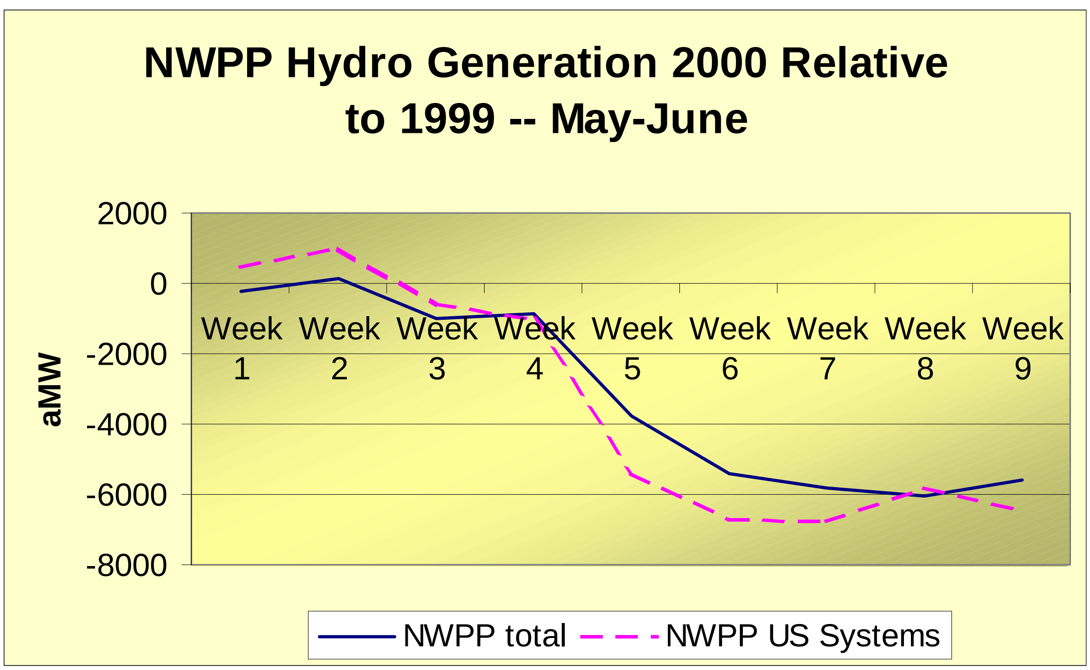
Although not too far from average in terms of overall runoff, the pattern of runoff in 2000 was somewhat unusual. The runoff pattern is shown on figure 4-1. This figure shows the unregulated monthly runoff volume at The Dalles in terms of thousands of acre-feet (KAF) for 1999, 2000, and for the 61 year average. As this figure shows, for the early part of the year, the 2000 runoff was above average. Beginning in May, however, the runoff essentially flattened out at a level below the 61-year average and well below the levels of 1999. This pattern persisted through the month of June.

Figure 4-1



In terms of hydropower generation, the weekly production for May and June of 2000 relative to 1999 is shown on Figure 4-2.

Figure 4-2



As Figure 4-2 shows, May-June 2000 weekly hydropower generation was down from 6,000-7,000 Megawatt-weeks relative to 1999 throughout most of June (weeks six through nine). The pattern of runoff probably "fooled" a number of participants in the market. The forecast was for a more or less average year. The runoff during February and March supported that forecast. It may be that decisions were made to make forward sales for June and beyond or, for those buying, to go short on the expectation of roughly average water and relatively abundant hydropower. Similarly, decisions to perform scheduled maintenance on thermal plants during the June time frame when high volumes of runoff were expected were also made. The subsequent runoff pattern confounded those decisions and significantly reduced the amount of hydropower both to meet regional loads and for export. It also seems likely that the relatively good water conditions in 1999 obscured the tightening of supplies.

5. Thermal Power Plant Outages

The latter part of June 2000 also experienced a significant amount of thermal power plant capacity that was out of service for either planned or unplanned reasons. To assess the amount of generation that was unavailable during the last week of June, 2000, staff examined hourly generation data from the Western Systems Coordinating Council (WSCC) Extra High Voltage (EHV) Data Base as well as supplementary data obtained through the cooperation of Bonneville and a number of Northwest utilities (Avista, Clark Public Utilities, Energy Northwest, PacifiCorp, Portland General, Puget Sound Energy).[3] Not all power plants report to the EHV system. Only about 70 percent of the capacity is included. Moreover, of those plants reporting, there are numerous instances of data lapses, i.e., the data shows no output from a particular plant although subsequent inquiry determines that the plant was operating. It is, however, the most comprehensive data source available. With the supplementary data, we were able to account for roughly 80 to 85 percent of the capacity in the Northwest.

Figure 5-1 shows data for a typical coal-fired power plant for the last 10 days in June.[4] The output of the plant is shown in terms of the percentage of its total summer capacity rating. Also overlaid on the data is the hourly load for the U.S. systems of the NWPP area. For this particular plant, it appears that going into the last 10 days of the month, the plant is operating at about 60 percent capacity due either to scheduled maintenance on one or more units or a prolonged forced outage. On the 27th, the plant loses another unit, dropping output to 30 percent. That unit comes back on the 30th. This outage we believe to be an unscheduled forced outage. This was the period of highest prices. An operator would not willingly forgo operation and miss out on the potential revenues, given the opportunity.

Staff reviewed the generation data to which we had access to identify outage states, focusing on the heavy load hours of the last week of June and, in particular, June 28. There is judgment involved as to whether a plant appeared to be in a planned outage or an extended forced outage. Staff identified 1,670 MW of capacity was out on a long-term basis, either planned or extended forced outages, and another 3,400 and 2,700 MW was on short-term forced outage status on the 27th and 28th respectively.

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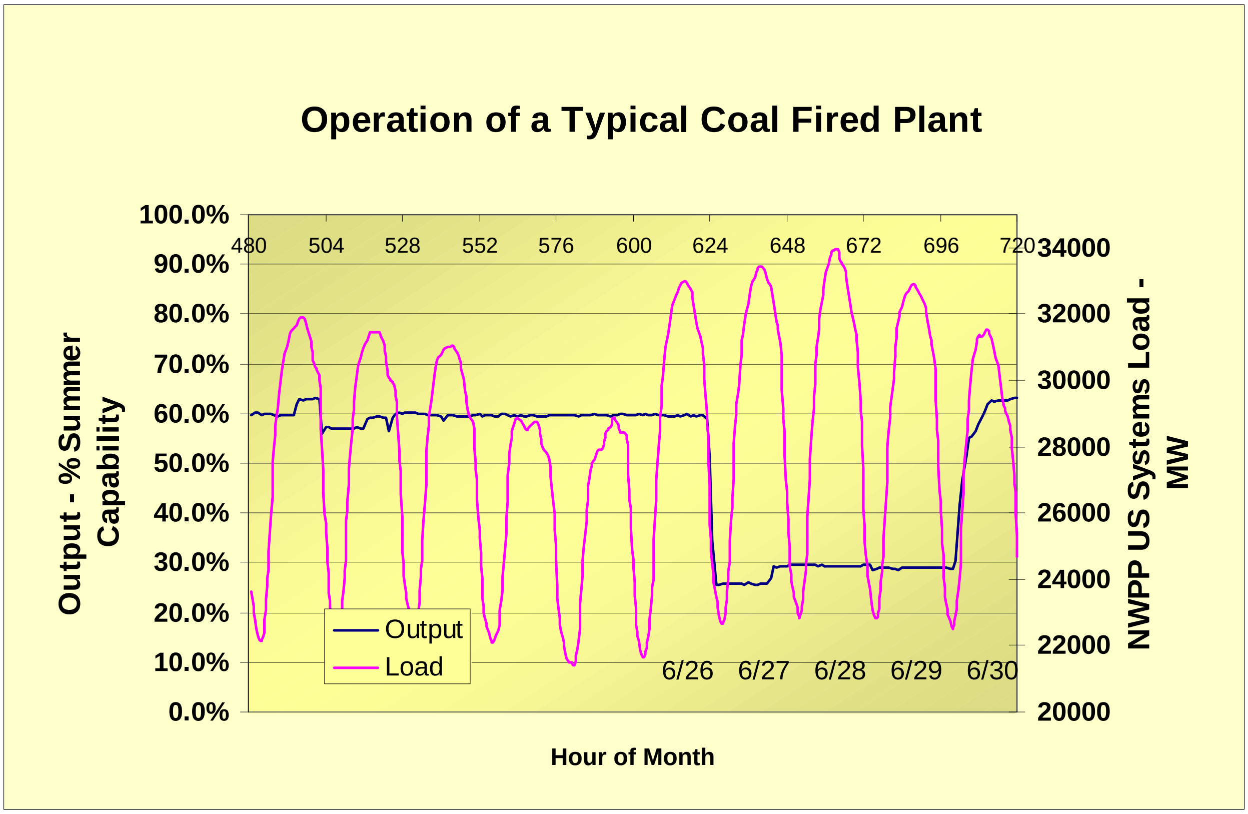
[3] The EHV data set could not be obtained directly from WSCC because of limitations imposed on its distribution by the WSCC membership. We were, however, able to obtain the data through the Oregon Public Utilities Commission who obtained the data from PacifiCorp.

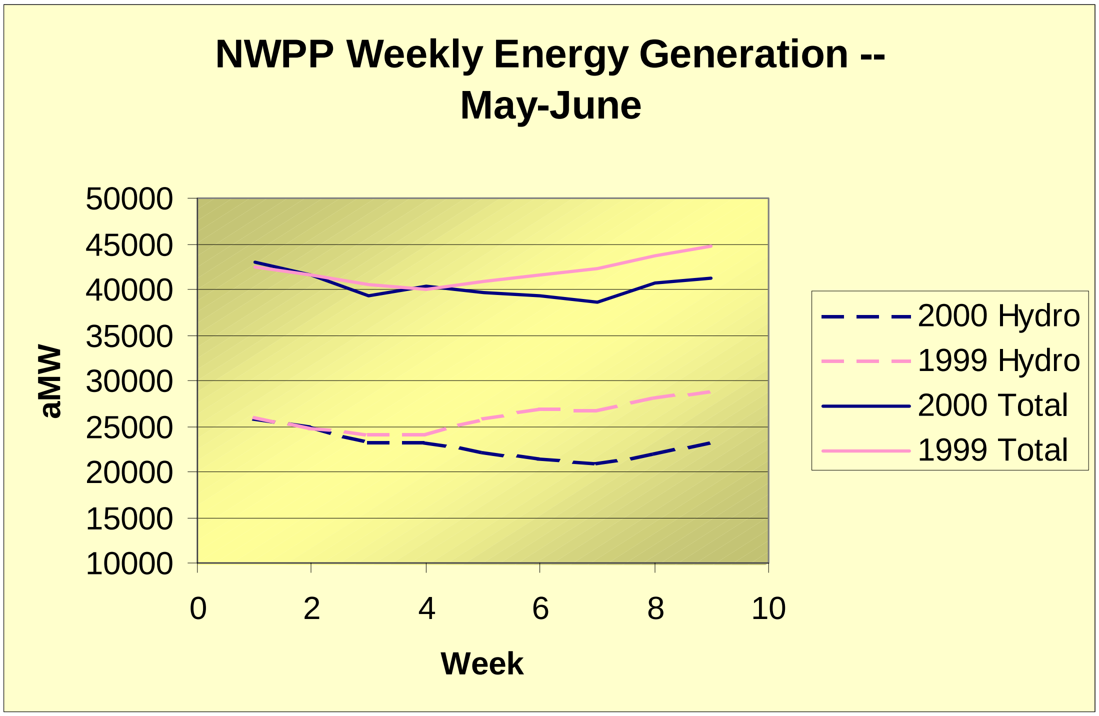
[4] As a condition of obtaining the power plant data, the Council agreed to use the data in such a way that no individual plant could be identified.

Figure 5-1



The total generation for the NWPP area for May and June is shown on Figure 5-2. As this figure indicates, thermal generation was able to make up for some but not all of the decrease in hydro generation. Thus at a time when demands were high in the Northwest and in California and the desert Southwest, the available generation was significantly reduced from 1999, when loads here and in California were significantly less.

Figure 5-2

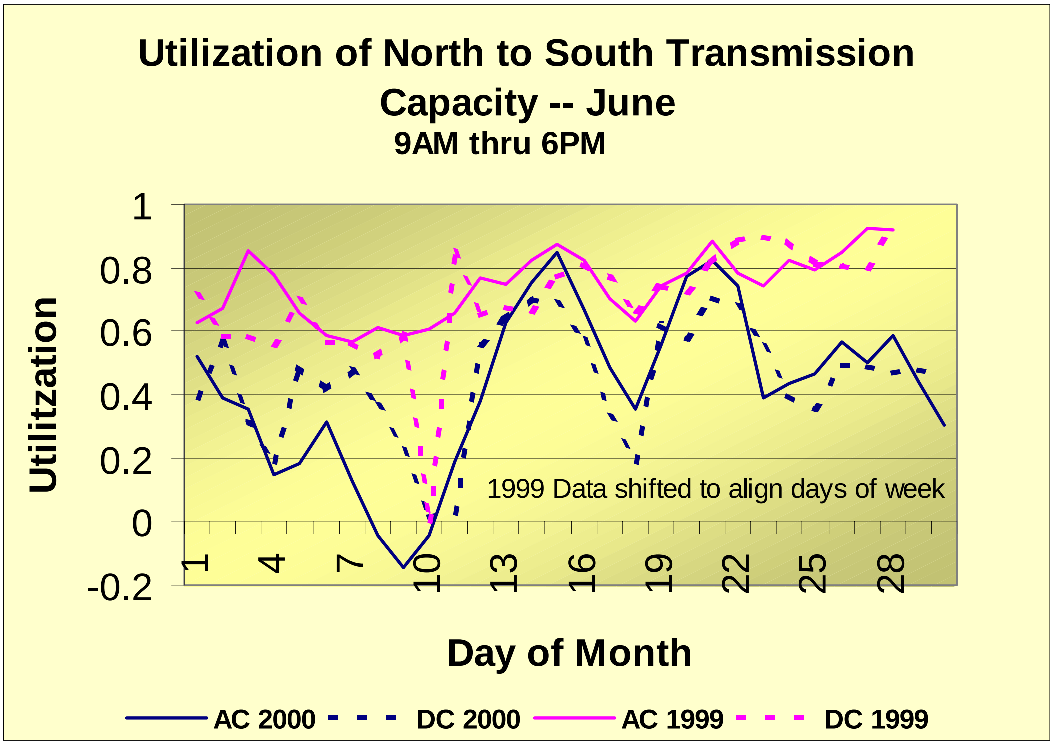


6. Transmission

Because the Northwest is part of the broader Western power market, what was happening on the transmission paths that link the Northwest with California and the desert Southwest are important to understand. There are a number of such transmission links. The most important are the California-Oregon Intertie (COI) or AC intertie that links the Northwest into Northern California, and the DC intertie that links into the Los Angeles area. We looked at the utilization of the North to South transfer capability during the month June for both 2000 and 1999. We calculated the average transfer during the period 9AM to 6 PM divided by the average transfer capability for that period. The period was chosen to coincide more closely to the actual hours of peak demand than the usual 6AM to 10 PM heavy load hour period.

As Figure 6-1 shows, in 1999 the AC and the DC generally operated closer to full capacity for most of the month than in 2000. This is particularly so in the last week of June 2000 when both the Northwest and California were experiencing high demand and high prices. The fact that the interties were essentially unconstrained during this period means that prices in the Northwest and California should be closely coupled and, as was shown in Figure 1-3, that was indeed the case.

Figure 6-1



7. Overall Load-Resource Balance

The Northwest and WSCC as a whole currently have a slight surplus of capacity under average load and water conditions. However, the combination of early runoff, high loads, outages of several large power plants and exports to the southwest market appear to have resulted in near-shortfalls in capacity in the Northwest this past summer. A preliminary analysis of loads and resources for the Northwest Power Pool - U.S. Systems for June 28 - the peak price day of June - indicates a peak net hourly load (native load plus exports) of about 41,000 MW. The native load was obtained from NWPP data while the exports were determined from the WSCC EHV transmission load data. Generation and imports were estimated from the WSCC EHV data set plus supplementary generation data provided by Northwest utilities. We were unable to identify more than 38,000 MW of capacity, including imports, available to meet these loads. Since loads were met that day there are obviously errors of estimation, data errors or both. This analysis has a high level of uncertainty. Hourly operating data was available for about 85 percent of installed capacity and the output of the remaining installed capacity was estimated. In addition, the data set could well have data errors. However, even considering the uncertainty, the evidence strongly suggests that the Northwest was operating under near-deficit conditions during the heavy-load hours of that day.

8. Oil and Natural Gas Prices

In a competitive market that is not operating close to its supply limits, the price of power is set by the operating cost of the highest operating cost plants that have to run to meet load. In the West during peak periods, those plants are typically oil or natural gas-fired simple-cycle combustion turbines. Consequently, the price of oil and natural gas will have an effect on the market price of electricity.

Natural gas prices are currently at very high levels. Prices in the spot market at Henry Hub in Louisiana have been over $5 recently and are expected to remain high for the next year at least. High gas prices are a result of a commodity cycle upswing in natural gas that has coincided with a period of high world oil prices. High oil prices can cause a surge in natural gas demand due to switching of dual fueled facilities to natural gas from oil. Figure 8-1 shows recent trends in oil and natural gas prices. Figure 8-2 shows how the natural gas price increase is likely associated with a three to five year commodity cycle for natural gas that has typified that fuel since it was deregulated in the mid 1980s.

Figure 8-1

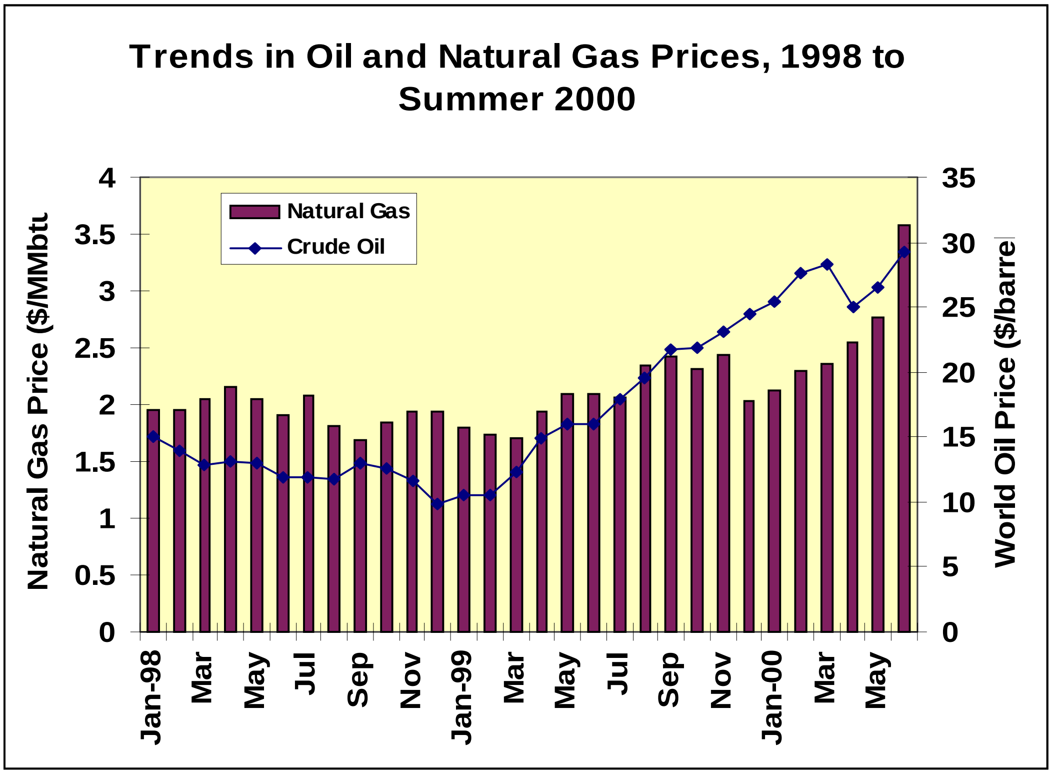
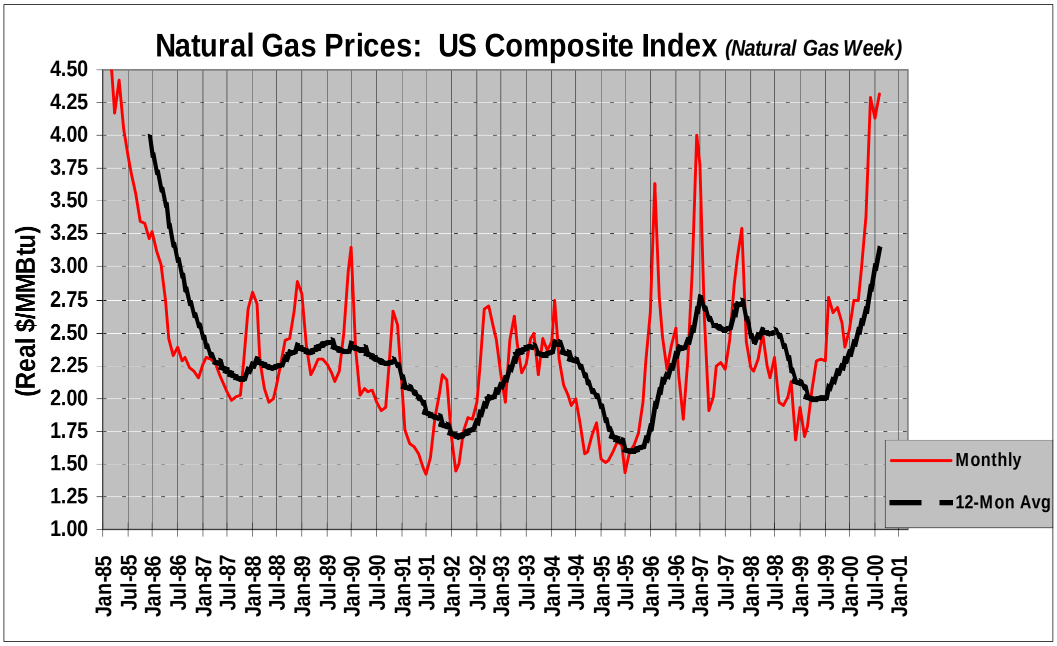
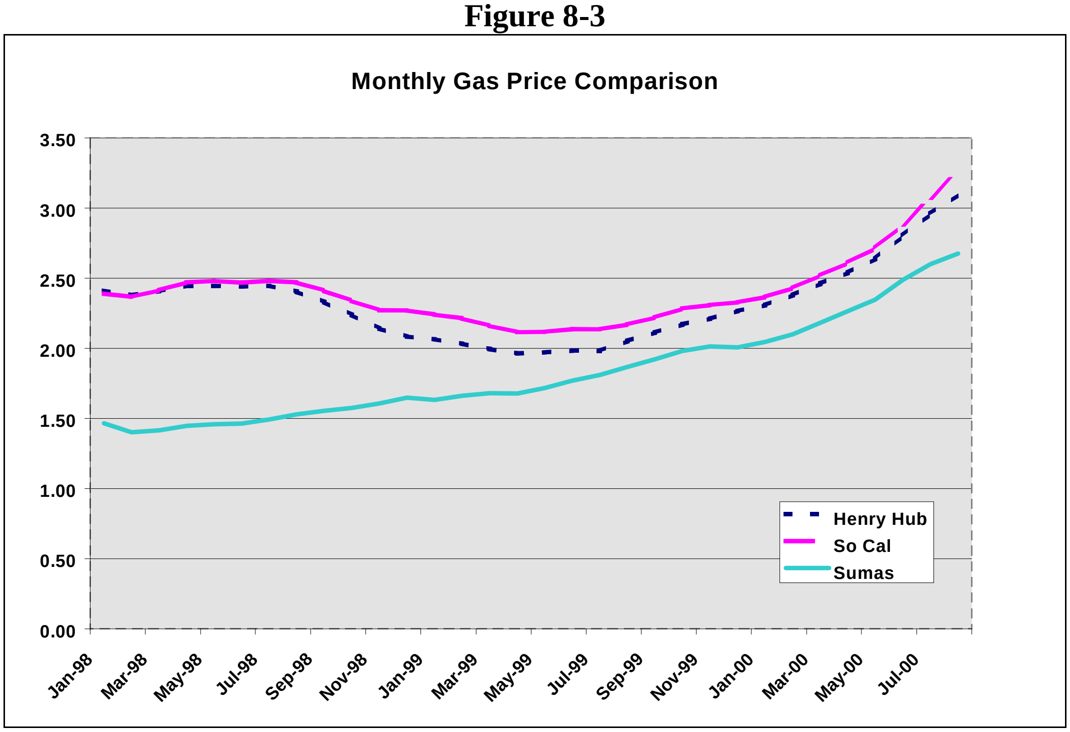


Figure 8-2



Natural gas prices in the Pacific Northwest have recently moved closer to national prices due to the recent and anticipated completion of new pipeline capacity from Alberta, Canada, to the East. Figure 8-3 shows Canadian natural gas prices at Sumas compared to Henry Hub spot prices and prices delivered into California.

Figure 8-3

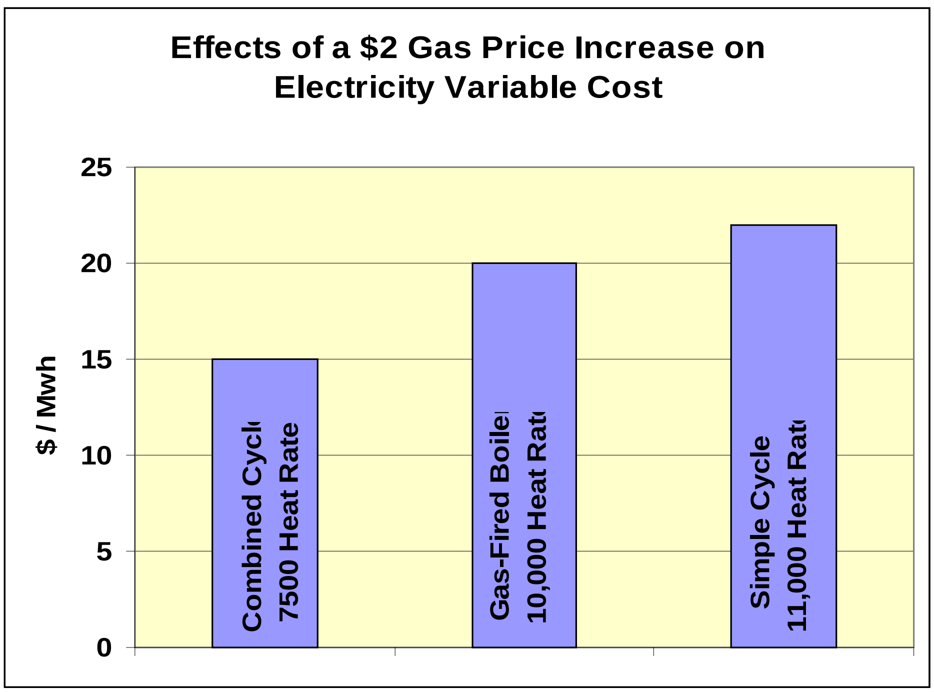


Between the summer of 1998 and the summer of 2000 natural gas prices at Sumas (on the Washington-British Columbia Border) to be delivered into the Northwest increased from about $1.50 per million Btu to $3.30. Prices into Southern California increased over the same period from about $2.40 to $4.18. Prices have moved substantially higher during late August and September.

During mid September, prices at Sumas were $4.60 and prices into Southern California were over $6.00, although the California prices were affected by a serious pipeline explosion. NYMEX futures prices indicate that natural gas prices are expected to decline over time, but remain above $4 for at least a year. A cold winter could send natural gas prices even higher.

Figure 8-4 illustrates the possible range of effects that a $2 increase in natural gas prices could have on the variable cost of natural gas-fired generation with different technologies. Changes in the variable cost of generation can translate directly into changes in electricity prices. Depending on the generating technology used, a $2 dollar increase in natural gas prices (roughly consistent with the doubling of gas prices in the last year) could increase electricity prices by between $15 per megawatt-hour and $22 per megawatt-hour. The increase in natural gas prices does not come close to explaining the increase in peak electricity prices. Average electricity prices during high load hours in the Pacific Northwest mid-Columbia market increased by $140 per megawatt-hour between June 1999 and June 2000, and light load hour prices increased by $46. The comparable price increases in Southern California were $113 and $28. The peak hour price increases experienced in California regularly hit the $750 per megawatt-hour price caps that were in place in June (subsequently lowered to $250 per MWhr).

Figure 8-4



This suggests that we should expect to see higher "competitive" electricity prices, i.e., the prices we would expect when the power system is not stressed and competitive pricing principles hold, for some time into the future. We expect high natural gas prices to stimulate development of additional gas resources and this is, in fact, already underway. The count of drilling rigs in the field in North Amercia is up from a low of about 350 to almost 800 now. Increased development, if successful, should bring down gas prices over time. The Council will be reviewing its gas supply and price outlook in the coming months.

In summary, while increased gas prices have and will increase the competitive market price of electricy, the effect of increased gas prices is relatively minor in relation to the non-competitive electricity prices observed when the system is under stress.

9. Lack of Price-Responsive Demand

A systemic problem associated with the immaturity of the competitive electricity market is the lack of a demand side to that market. The responsiveness of demand to price is essential to an efficiently operating competitive market. Price responsiveness is a key mechanism to balancing supply and demand. Without some degree of price responsiveness, there is no check on the prices that can be charged when supplies are tight, except for artificial caps.

It may be worth reviewing a simplified representation of the basic economics that underlie markets, including the competitive wholesale power market. Figure 9-1 illustrates supply of and demand for electricity at a time at which the system is unstressed. The stair-step curve is the supply curve, representing the quantity of electricity that will be supplied at a given price. The prices and incremental quantities correspond to the operating costs and capacities of different generators on the system at any point in time. The near-vertical line represents the demand curve. The dotted lines on either side represent the range of variation in demand resulting from weather conditions, e.g., in the summer, a cool day moves the demand curve to the left, a hot day moves it to the right.

The demand curve is nearly vertical because, at present, the amount of electricity demanded is virtually independent of wholesale price. The vast majority of consumers do not see market prices in anything approaching real time. As a result, most have done little if any thinking about what they might do to reduce their demands if power were very expensive. Even in California, which has theoretically opened its retail markets to competition, very few end-users see a price signal in time to do anything about it. For most, the cost consequences of periods of high prices are averaged in with the costs from periods of less extreme prices and what effect the consumer does feel is felt well after the fact.

The wholesale price is determined where the demand curve intersects the supply curve. In the situation illustrated in Figure 9-1, the lack of price responsiveness isn't particularly critical, because the demand curve intersects the supply curve at a relatively flat portion of the supply curve. Changing demand is not going to affect the wholesale price significantly.

Figure 9-1

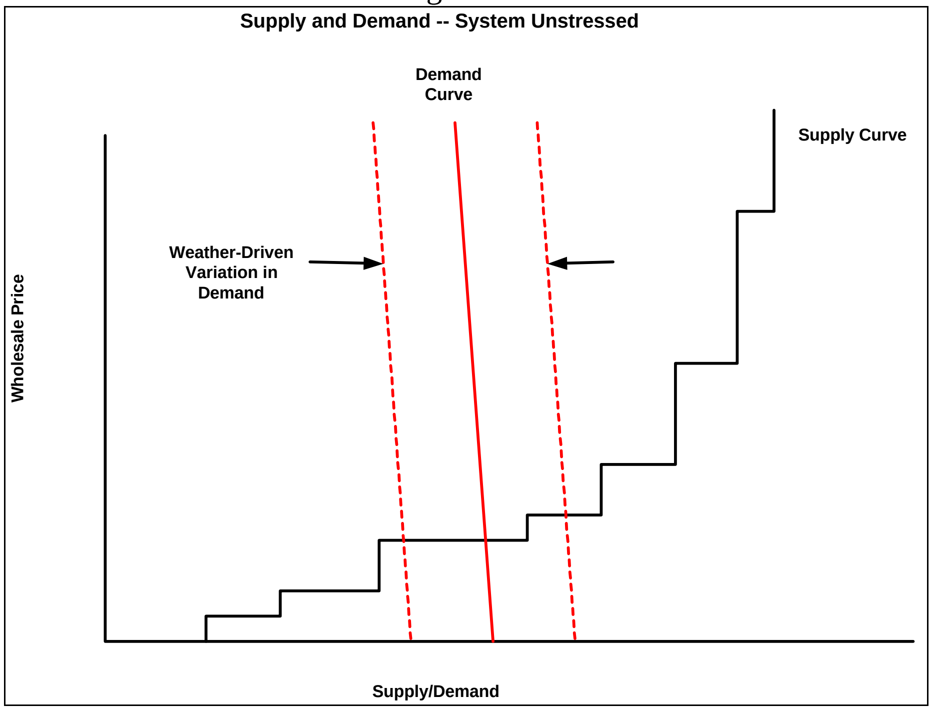


Figure 9-2 illustrates the situation that we believe existed this summer. Growth in demand has occurred without any appreciable additions to the supply curve. Moreover, high temperatures and increased air-conditioning loads mean that we have been toward the right hand side of the band of weather-driven variation. In this instance, the demand curve intersects the supply curve at the steep part of the curve. Relatively small changes in demand can have significant effects on price or can mean the difference between being able to meet load and not.

Figure 9-2

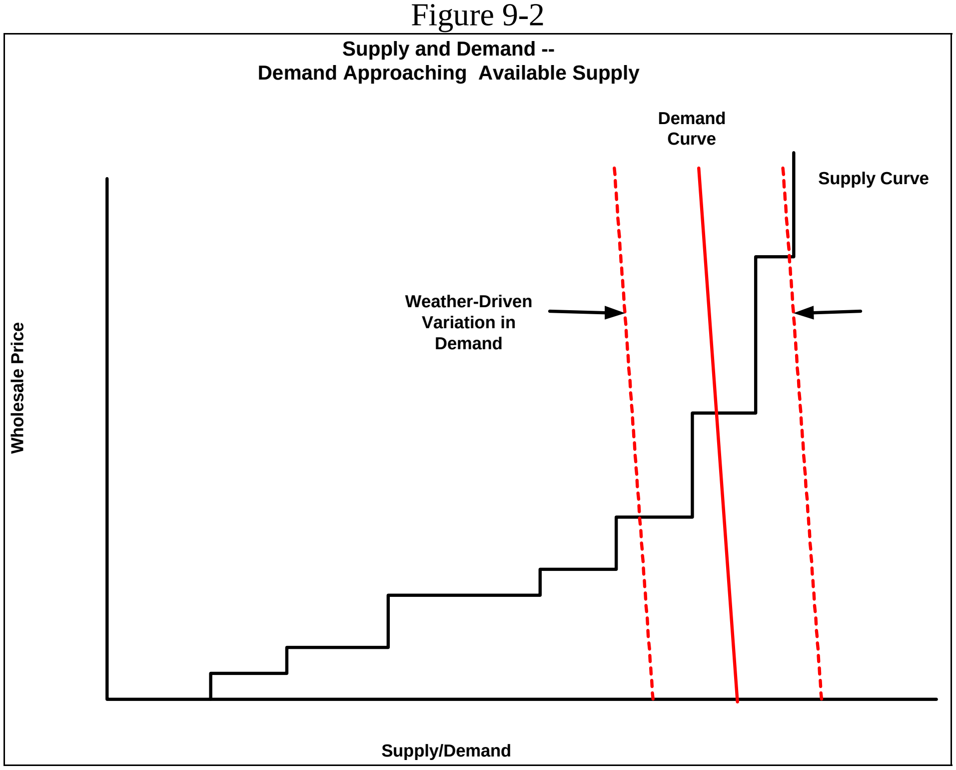
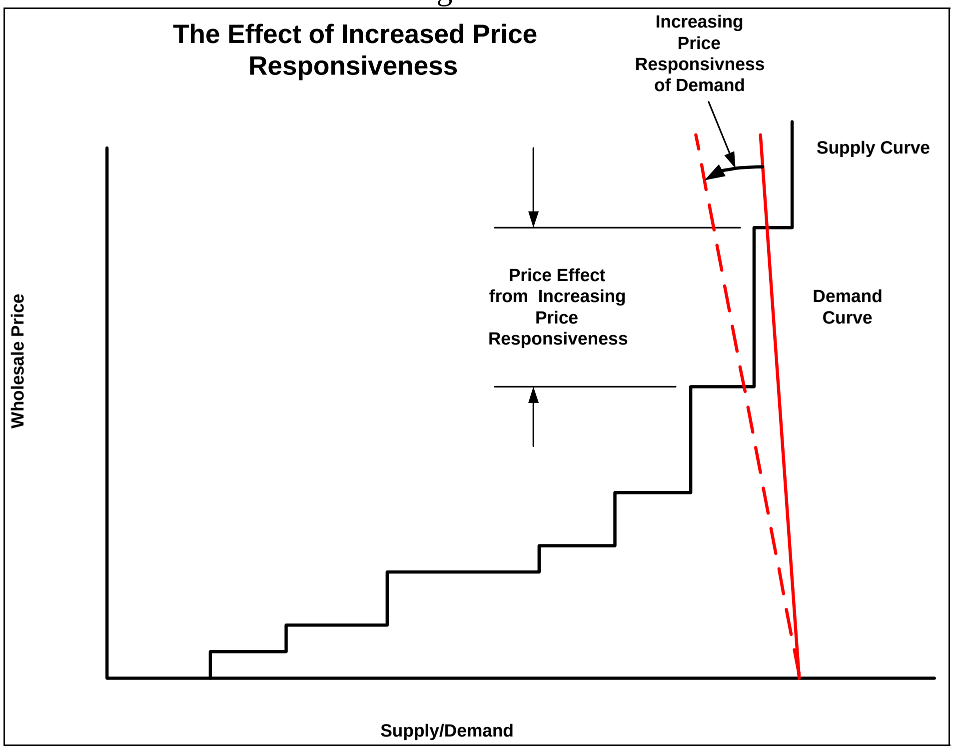


Figure 9-3 illustrates the benefit of developing greater price responsiveness in demand. The effect of price responsiveness is to bend the demand curve to the left, i.e., at some point, as price increases, the demand decreases. If demand and supply were intersecting in the relatively flat section of the supply curve, there would be little if any affect on price. But, since we are in the steep part of the supply curve, a relatively small increase in price responsiveness can have a fairly significant effect on price.

Figure 9-3



Early Experience in Increasing Demand Responsiveness

The early experience supports the idea that increased demand responsiveness in periods of tight supplies can be achieved. We don't yet have the kind of experience that would support a precise estimate of the amount of demand reduction that might result from a specific price signal. However, it seems very likely that several hundred, and quite likely more than 1,000, megawatts will be available in the Northwest when we provide the right incentives.

The simplest way to increase demand responsiveness, in concept, would be to make sure that retail customers see the actual cost to the power system of providing power at all times (i.e. "real-time" retail prices). Real-time prices are used in some places (e.g. in the province of Alberta) and have resulted in substantial demand response. However, for a variety of reasons, real-time prices are not in significant use in this region now, and we don't expect them to become common in the foreseeable future.

There are alternatives to real-time prices, however. Instead of handing the customer a bill for real-time costs of electricity use, we can offer a real-time opportunity to be paid (on the basis of real-time power costs) for reducing use at specific times. This approach requires prior contractual agreements and appropriate metering and is limited in the range of customers who participate, but can offer incentives to reduce use at peak load hours that are roughly equivalent to the incentives offered by real-time prices. These are NOT interruptible contracts where the whole facility losses power when the contract is exercised. They ARE arrangements where the participants agree to manage their loads to achieve load reduction in return for an agreed-upon share of the power revenues or savings.

Several utilities in the region have offered such alternatives on a pilot or limited basis in the last year or so. B.C. Hydro offered its Price Dispatched Curtailment program on a pilot basis beginning in 1998, and has since converted it to a continuing program. This program offers to remarket power made available by load reductions by certain customers, with the profit from sale of the power on the open market shared by B.C. Hydro and the customer. The program is exercised when B.C. Hydro has no surplus of its own to market, and transmission capacity is available to move the freed-up power to market (e.g. California). On one occasion during the pilot phase of this program, B.C. Hydro obtained 200 MW of load reduction.

Bonneville Power Administration and Portland General Electric have both initiated Demand Exchange programs during the summer of this year. Their programs, while not identical, are similar, both based on the work of the same contractor, Apogee Interactive. An offer is initiated when high prices are expected and the utility either expects to need to buy from the market to serve its customers, or has an opportunity to sell into the market and make a margin of profit. The utility notifies customers participating in the program of the hours and levels of reduction it is seeking, and the level of compensation it is offering for load reductions. The customer has the option of not responding at all, or offering an amount of load it is willing to cut in return for the offered compensation. The utility then re-evaluates the market prospects and the load reduction offers and notifies customers chosen to reduce load and receive compensation.

The Demand Exchange programs were functioning for only the latter part of this summer, but the experience has been encouraging. PGE obtained load reductions from its customers 22 times. Load reductions ranged from 30 MW to over 100 MW and the total so far has been 8,300 MWh. The economic benefit of the program, compared to simply serving loads at average costs and buying from the market when necessary, has been about $3 million, equally divided between the utility and the participating customers. We don't have comparable data from the Bonneville program, but we do know that they have achieved their target levels of participation and expect to expand the program to 300 MW by this winter and to 800 MW by next year.

In addition to the formal programs, there were a few ad hoc deals made between utilities and customers during the tight-supply episode at the end of June. Our best estimate is that those deals have totaled 80 to 100 MW.

Large industrial and commercial customers are typically thought to be the best targets. What can be done depends almost entirely on the nature of the facility, processes employed and the ingenuity of the operators. For example, air separation would be a prime target, provided the operation had sufficient storage. Similarly, paper mills employing mechanical pulping, an electricity-intensive process, can interrupt pulping operations without disrupting production if they have adequate pulp in storage to sustain operation of the rest of the mill or have excess pulping capacity. Aluminum plants can rotate electric current reductions through different pot lines. Facilities with back-up generation could either go off the grid or dispatch power into the grid. Large commercial buildings, particularly those with modern control systems, may be able to increase air conditioning (or heating) set points when prices are high. An apparently significant source of load growth in the region are so-called "server farms" that house the internet servers for the growing "dotcom" industry. Because these facilities require a high degree of reliability, they incorporate back-up generation. Use of this back-up generation could help. Individually, the contributions are relatively small. Collectively, they could be quite large.

The operators of industrial processes and commercial facilities are quick to point out that they are not in the electricity business and don't particularly want to be. However, if the economic signals are sufficient, that resistance may be overcome. It will, however, take a lot of hard, up-front work to get a significant amount of demand reduction in place. That work needs to begin now. It is noteworthy that the California Legislature, responding to this summer's price spikes, appropriated $50 million for the development of demand management opportunities.

10. The "California Effect"

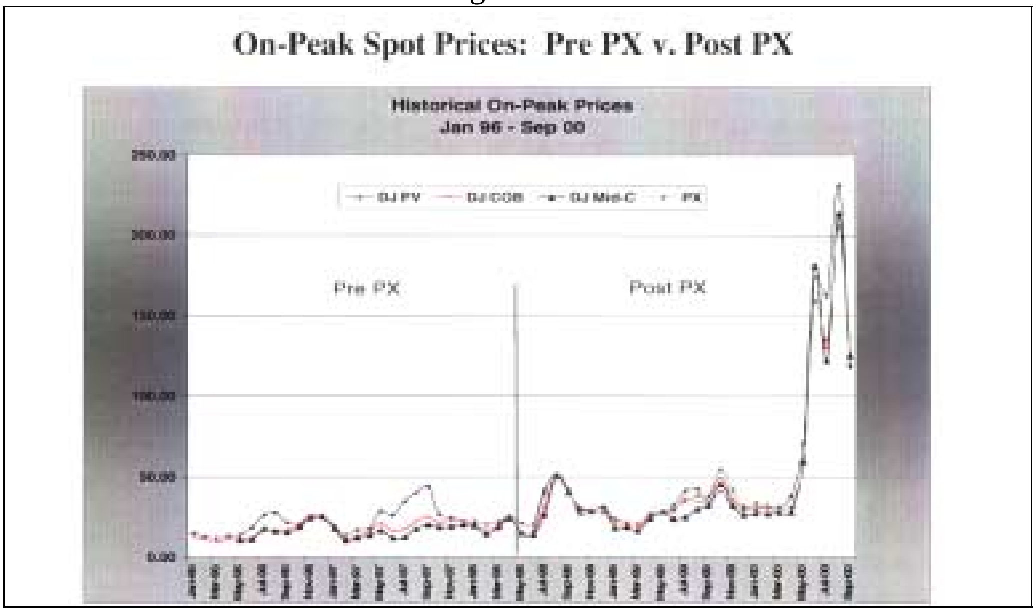
So long as transmission constraints have not "decoupled" the California market from the Northwest, what happens in California will have a definite effect on the Northwest. California is a larger market than the Northwest, and it has moved much farther down the path to restructuring than any of the other Western states. Moreover, it has done so in its own way. It has created a very complex market structure that many believe was designed as much to facilitate dealing with the stranded cost issues of the California investor-owned utilities as it was to open markets to competition.

The state's investor-owned utilities are required, with limited exception, to sell the power from generation they still own (largely nuclear and hydro) into the day-ahead and hour-ahead markets operated by the California Power Exchange (CalPX) and to meet their loads with purchases from that market. The CalPX is a single-price market -- all sellers whose bids are accepted are paid the market-clearing price -- the highest price accepted in order to meet loads. Operationally, if there is an imbalance between the scheduled supply and the forecast demand, the difference is made up in a "real-time" imbalance market operated by the California Independent System Operator(CAISO).

The primary responsibility of the CAISO is reliability as well as ensuring open, non-discriminatory access to the transmission system and the efficient operation of electricity markets. The CAISO provides a number of ancillary services through day-ahead and hour-ahead markets for regulation, spinning reserves, non-spinning reserves and replacement reserves. There is no cap on the prices that can be bid in the CalPX. However there are caps on the markets in the CAISO markets. At the time of primary interest in this analysis, the cap was $750/MWHr. These caps become de facto caps for the PX as well. If prices in the PX exceed the ISO cap, the incentive is for the purchaser to submit a schedule to the ISO that does not match expected load. The ISO then must balance the schedule in the imbalance market. There is at least one exception to the cap in the ISO. This occurs when the ISO finds it necessary to go "out of market" to purchase energy, i.e., arrange bi-lateral purchases with suppliers outside the ISO control area to maintain adequate reserve margins.

For most of its existence (since May of 1998), one could probably conclude that the California market has operated reasonably well. Figure 10-1 shows a comparison of various Western market hub prices pre- and post CalPX. Until this year, there is little evidence of prices going to non-competitive levels.

Figure 10-1



Source: Bonneville Power Administration

We have done no independent analysis of the operation of the California market. We have, instead, relied primarily on the work of the Market Analysis group at the CAISO and a paper prepared by the independent members of the Market Surveillance Committee of the CAISO.[5] [6] . The California market structure is undergoing a great deal of scrutiny in California at the present, and some redesign seems almost certain. It is very unlikely that anything we would have to say on the subject will substantially affect the outcome. We would offer some observations based on our review of the analyses cited above. We believe that when the system is strained, as it has been this summer, the incentives inherent in the California market structure serve to exacerbate price volatility.

Limitations on the Ability of California Distribution Utilities to Hedge with Forward Contracts

The California Public Utilities Commission has limited the ability of the California IOUs to hedge their risk through purchases of forward contracts. This restriction was probably a reaction to what turned out to be quite expensive long-term purchases made by California utilities in the past. In the current environment, it has the effect of forcing a larger proportion of the utilities' load to be met in the spot market. Had a greater proportion of the load been covered by forward contracts, less of the load would have been subject to volatile spot market prices. In addition, the Market Surveillance Committee paper contends that these restrictions reduce the incentive of generators to bid aggressively into the PX and "significantly enhance the ability of generation owners in the California market to raise prices in the PX and ISO energy and ancillary service markets."[7]

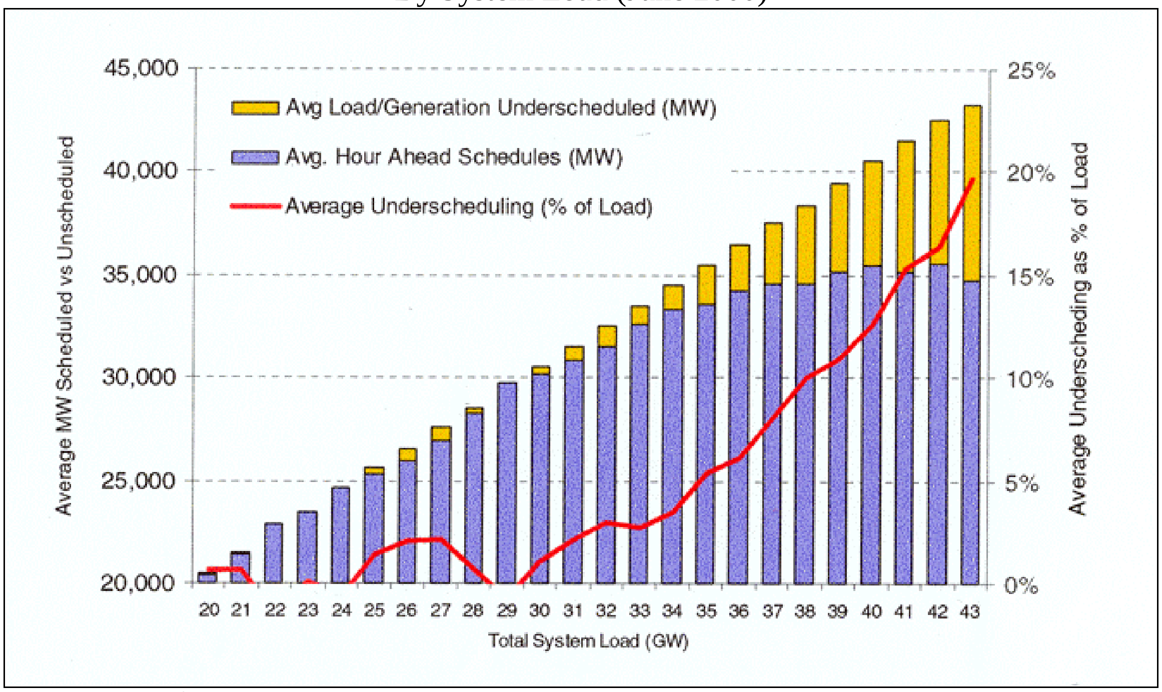
[5] *Report on California Energy Market Issues and Performance: May-June, 2000*, Special Report prepared by the Department of Market Analysis, California Independent System Operator, August 10, 2000.
[6] Wolak, Frank I., Chairman; Robert Nordhaus, Member, Carl Shapiro, Member, Market Surveillance Committee of the California Indpendent System Operator, *"An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets"*, , September 6, 2000.
[7] Wolak, p.7.

Underscheduling in the Day-Ahead and Hour-Ahead Markets

Perhaps more pernicious is the degree to which the distribution utilities and suppliers underschedule in the day-ahead and hour-ahead markets when the system is stressed. Figure 10-2 shows the amount of underscheduling as a function of system load that occurred this June. This chart clearly shows that the amount of underscheduling increases significantly when total load approaches 75 to 80 percent of the maximum load experienced. The amount of underscheduling reaches almost 20 percent of the peak load.

Figure 10-1

California ISO Average Underscheduling of Loads and Generation By System Load (June 2000)



Source:California ISO

Absent some other mechanism, the effect of this degree of underscheduling is to require the ISO to attempt to reconcile a large imbalance in the real-time market. Supplies are tight, time is short and the operators must scramble to purchase resources. Their primary responsibility is to keep the lights on. They are in no position to drive hard bargains with potential suppliers. The suppliers can pretty much get what they ask for.

The ISO recognized this issue and implemented a scheme for purchasing replacement reserves when schedules do not meet forecast demand. The Market Surveillance Committee paper contends that this scheme has actually increased the incentive for suppliers to underschedule in the day-ahead market. By selling replacement reserves, they could be paid at the cap level for capacity and, if called upon to generate, also be paid the cap for the energy they provide.

Unfortunately, the market participants are only doing what the incentives tell them to do. Because there is a cap in ISO but not in the PX, when supplies become tight the incentive is for the distribution utilities to have load supplied out of the ISO. From the standpoint of suppliers, they know that the pressure of a real-time market will work to their benefit. Moreover, there is potential for earning twice the cap for supplying replacement reserves or for suppliers located within the ISO control area to "launder" megawatts by selling them to out-of-market participants who can resell to the ISO at uncapped prices.

We are not going to attempt to put forward remedies for the California market structure. However, remedies are essential, not only for California but for the rest of the West. To the extent that the incentives adversely affect the prices in the California market, they adversely affect the market prices in the rest of the West.

11. Did Market Participants Manipulate the Market?

One of the concerns heard frequently this summer was that some market participants manipulated the market or exercised undue market power. Clearly the prices we have seen are well above a "competitive" price, if that is defined as the operating cost of the most expensive unit on the system that must run to meet load. It is not clear, however, whether this is the result of the exercise of market power, or the normal functioning of a market when supplies are tight and there is no moderating effect of price responsiveness. If you happen to have a commodity for which demand was high and supplies were limited, most of us would charge more than the cost of production for that commodity. Charging what the market will bear is not illegal.

The Council examined the generating records of most Northwest power plants to see if there was evidence of "withholding," i.e., holding power off the market to drive up prices[8]. We plotted the output of the plants along with regional demand and hourly prices in the California market. We found no clear evidence of withholding. Power plants were generally being operated as one would expect given the characteristics of the plants and a situation of overall tight supplies. Hydropower plants were typically following load or operating "flat out." Thermal plants were typically running flat out or, in the case of units with higher operating costs, backed down during the off-peak periods. For the very few instances of operating patterns that might be interpreted as withholding, the quantities involved were too small to affect the market. Our general impression is that Northwest operators, at least, were trying very hard to meet loads.

The Council did not have access to information that would permit analysis of the bidding strategies of different market participants. We do not know whether that information would suggest market manipulation or the undue exercise of market power.

12. The Outlook for New Generation

If the fundamental reason behind the prices seen this summer is an overall tightness of supply, what are the prospects for new development? When the Council did its analysis of regional power supply adequacy, an attempt was made to assess the likelihood of market-driven development of new generation using the AURORA model.[9] AURORA models the operation and expansion of resources throughout the entire WSCC. While its primary use is for wholesale price forecasting, it can also be used to assess development of new generation. This assessment suggested that the principal constraint to power plant development has been wholesale power prices. That study suggested that though favorable project-specific circumstances, such as municipal financing, might

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[8] As noted earlier, we had access to generation data for approximately 85 percent of the generation capacity in the Northwest.

[9] AURORA Electric Market Model, EPIS Inc., 18813 Willamette Dr., West Linn, OR 97068, www.epis.com

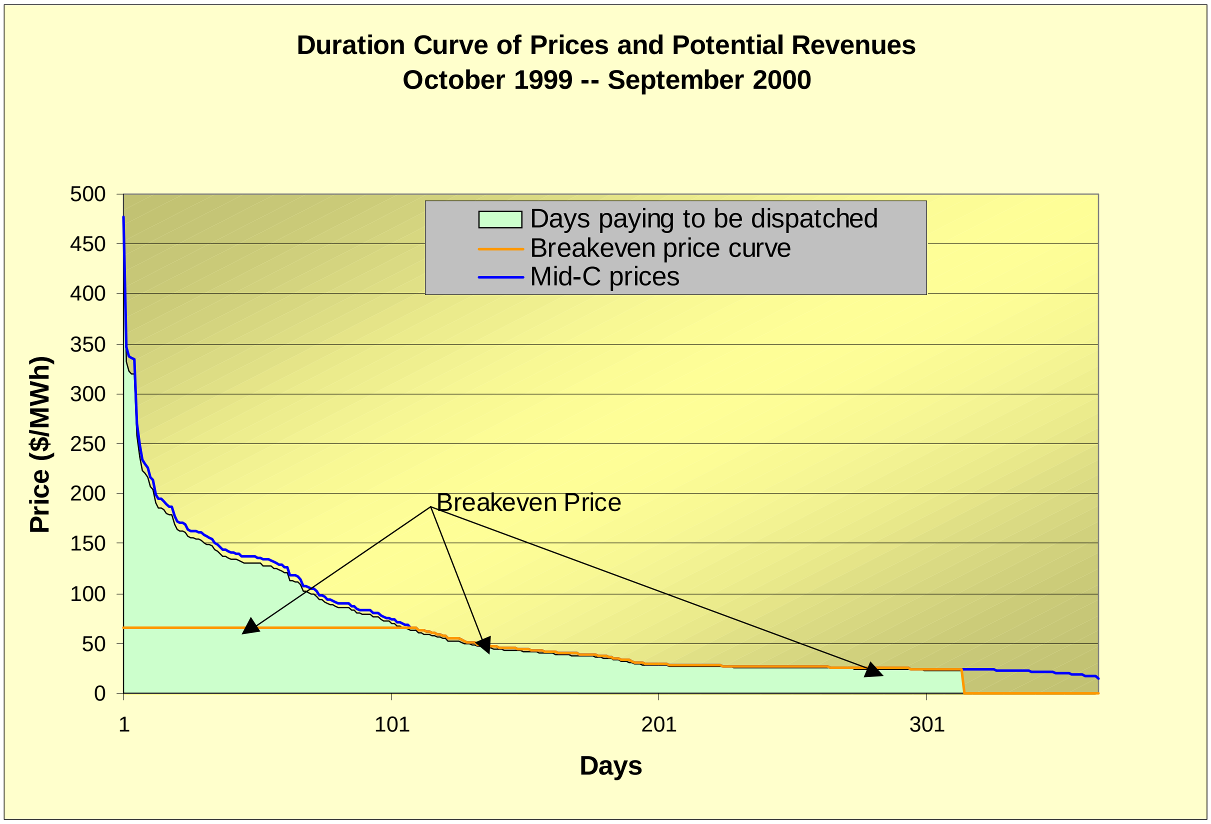
result in the development of a project or two in the next couple of years, forecast market prices would not support the development of new capacity until about 2004 at the earliest.

Since that assessment was completed, two things have happened. About 750 megawatts of new gas-fired combined-cycle combustion turbine capacity has begun construction. And market prices of both electricity and natural gas have risen to much higher levels than those included in our earlier analysis. Staff has analyzed the ability of a new combined cycle power plant to cover its fixed and operating costs and reasonable return based on the revenues it would earn by selling at historical market prices. In earlier years, the results of this analysis have been negative. This year, the result is positive. Figure 12-1 shows the duration curve of weighted average wholesale prices at Mid-C for the period October 1999 through September 2000. The shaded area shows days in which prices were high enough to justify operation of a combined-cycle combustion turbine (CCCT), i.e. prices are at least as great as the variable operating cost of the CCCT. This analysis takes into account the higher gas prices paid this year. As this chart shows, a CCCT would have operated all but about 50 days of the year. The break even line indicates that if prices had not gotten above about $65/MWHr, the plant would have fully covered its fixed and variable costs. As it was, the prices exceeded that level for over 100 days. A CCCT receiving market prices for the October through September period would have earned almost 1.6 times its annual revenue requirement. The "excess" would be profit, or revenues that help make up for years when prices are not so good.

This is consistent with the results reported by the California Energy Commission (CEC).[10] The CEC reports that for August of this year, a new plant would have earned something like 75 to 85 percent of its total revenue requirement for the *year* and that over the last 12 months (September 1999 through August 2000), such a plant would thus far have earned 2.5 to 3 times its annual revenue requirement.

[10] California Energy Commission., http://www.energy.ca.gov/electricity/wepr/2000-08/index.html

Figure 12-1

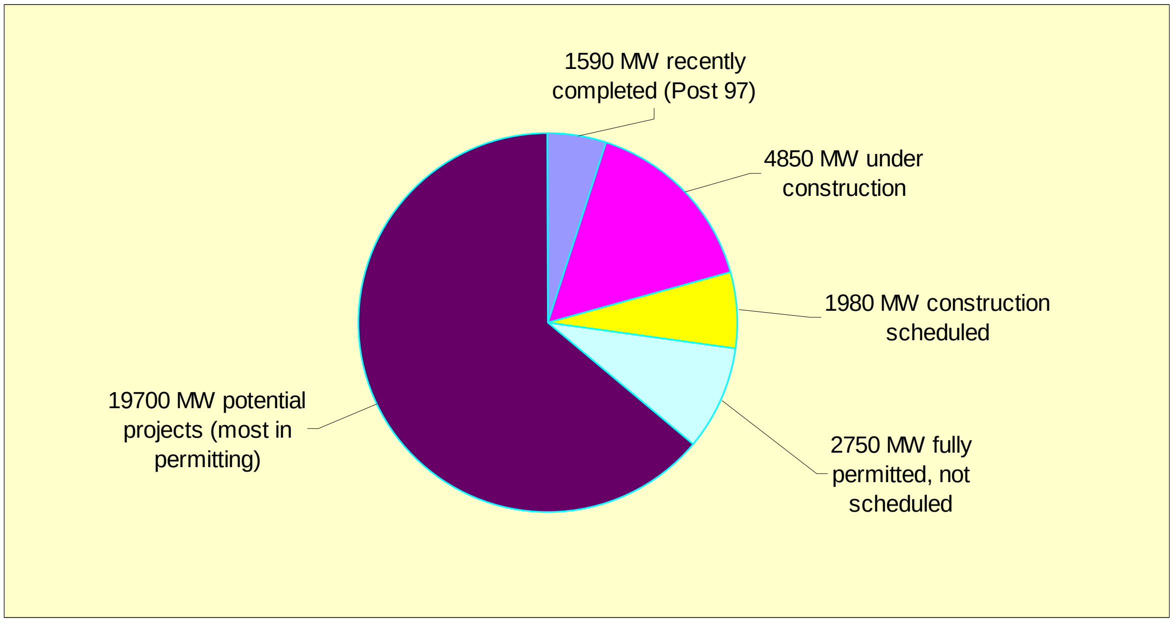


From these analyses, it appears that **if** the electricity and gas prices of the past year were to continue, there would be substantial incentive for the construction of new generation.

New Power Plant Development Activity

Looking at the entire WSCC, there is a significant amount of new generation that is either under construction, construction is pending, is fully sited but not scheduled, or is at least under consideration. The inventory in shown on Figure 12-2.

Figure 12-2
Generating Capacity Additions in the WSCC



The scheduled on-line dates of the planned capacity additions is shown on Figure 12-3. As this chart indicates, the under-construction and scheduled capacity will just about keep pace with the growth in peak summer loads in the WSCC over the next two years. Construction lead times are such that developers need not commit to construction earlier than two years before the on-line date. This, however, presumes the developer has ordered a turbine in advance or can purchase delivery from someone else. The lead time for a new turbine is supposedly 46 months.

Figure 12-3
Schedule of WSCC Capacity Additions (On-Line Year)

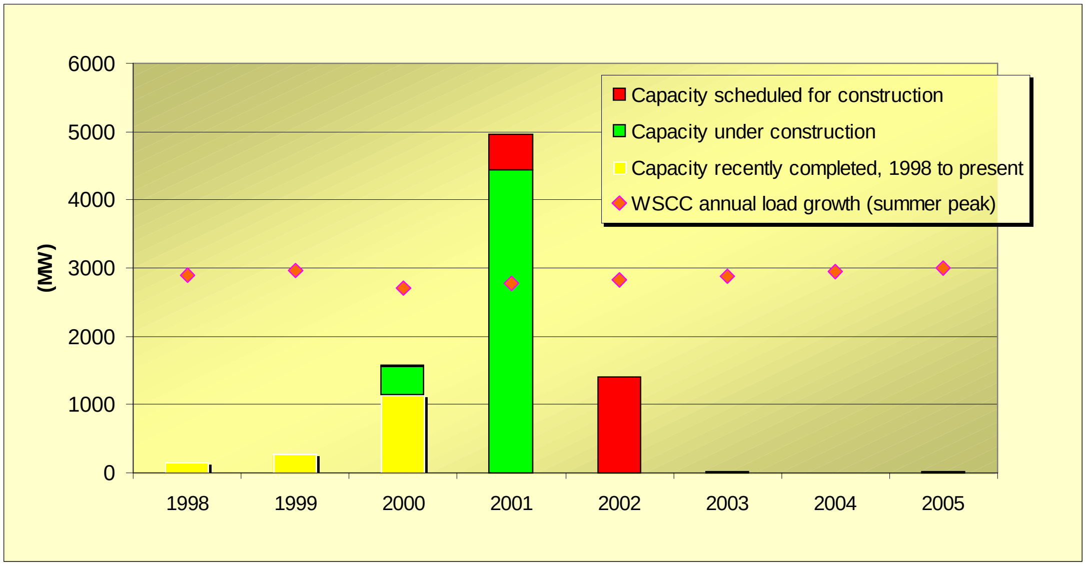


Figure 12-4 shows the scheduled addtions by type. As this clearly shows, development is weighted overwhelmingly toward gas-fired combustion turbines.

Figure 12-4
WSCC Capacity Additions (Recently Completed, Under Construction and Scheduled) by Type

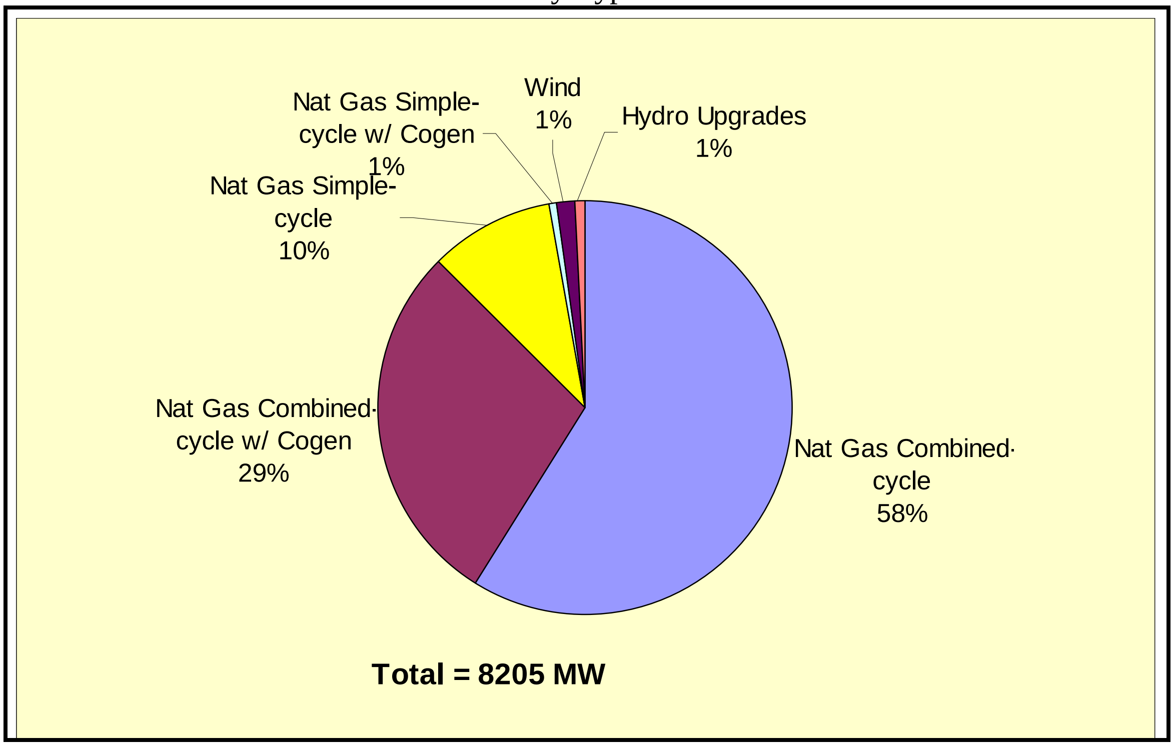


Figure 12-5 shows the location and status of the "active" Northwest projects of which we are aware. Again, natural gas-fired units are by far the largest component. As Figure 12-6 shows, the inventory of active projects in the Northwest has increased substantially over the last year, suggesting developers are seeing a favorable climate for development. The siting process does not appear to have been a significant barrier in that there is a backlog of permitted sites at which construction has yet to begin.

Figure 12-5
Location of NW Projects

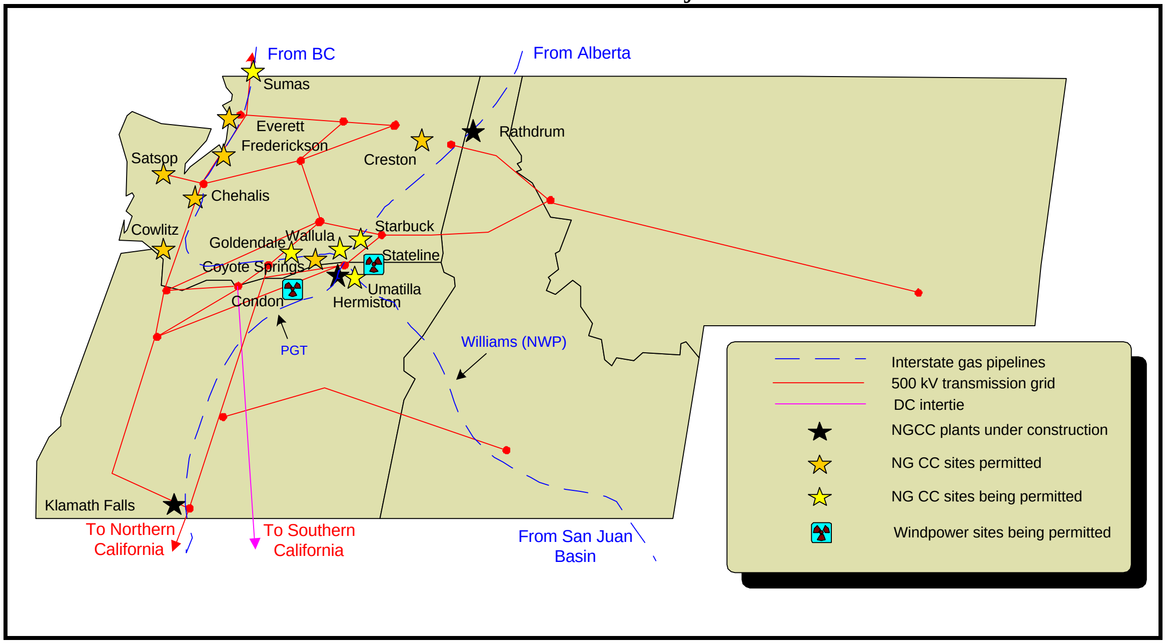
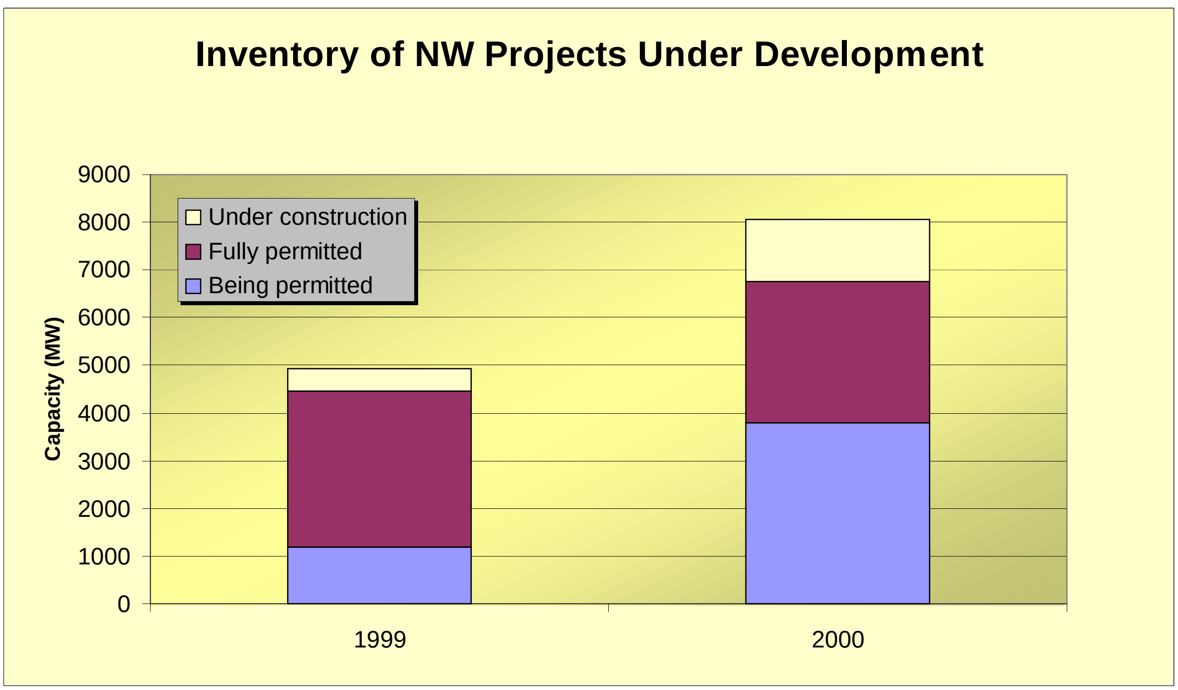


Figure 12-6



How Much Development Actually Will Take Place?

Developer activity certainly suggests that a substantial amount of new generation will be developed over the next two to three years. Still, we can only be sure about the 1,300 MW under construction. Should the next couple of years see good hydropower conditions, mild winters and cool summers, market prices could fall substantially. If that were to be the case, some of the currently anticipated new generation could be delayed.

This raises the question of whether we can rely on the market to develop sufficient resources to assure reliability and mitigate extreme price spikes. The variability of the hydropower system introduces an uncertainty for power plant developers in the Northwest that does not exist in most other parts of the country. When we have tried to simulate the development of new generation using the AURORA model, we have typically assumed that developers would look at whether they could cover their costs under "average price" hydropower conditions and average loads. The amount that gets developed with these assumptions is not sufficient to meet needs under poor hydro conditions and extreme loads. This analysis requires a number of assumptions, many of which are about things we don't know very much about. In particular, the results are very sensitive to assumptions regarding the amount and cost of demand reduction that is available. For that reason, we are reluctant to treat the results as being definitive. Still, for reliability purposes, it may be necessary to provide incentives for some capacity that can be dispatched for reliability purposes or to mitigate extreme price spikes. How the costs of such capacity would be borne and who would control this capacity are open questions.

The issue of natural gas supply and deliverability is also of some concern. There are concerns that under extreme winter conditions we might be unable to fully meet the requirements of existing gas-fired generation and other gas users, let alone additional thousands of megawatts of gas-fired generation. As noted earlier, exploration activity is underway that we expect will result in additional gas supplies. Similarly, pipeline capacity can be expanded relatively easily through compression and looping of the system. Nonetheless, this all takes time and the commitment of resources. The Council is looking into the deliverability issue for this winter as well as longer term supply and deliverability questions.

Recommendations

Encourage the Greater Use of Risk Mitigation Mechanisms

One of the characteristics of a commodity market is the emergence of mechanisms to manage risk and electricity is rapidly becoming a commodity market. These mechanisms include actual physical longer-term contracts for supply, futures contracts, financial hedging mechanisms, and so on. These mechanisms can limit exposure to high prices. At the same time, however, there is always the risk that they will prove more costly than the spot market. Risk mitigation comes at a cost and it is not realistic to be fully hedged for all risk. But the experience of this summer suggests there could be greater use of risk management tools.

As noted earlier, we believe the limitation on forward contracting by California utilities was a contributing factor to the price extremes of this summer. We believe the same is true of other market participants in the Northwest and elsewhere. While opportunities to enter into forward contracts and other hedging arrangements have existed, it may be that the protracted period of low market prices for electricity lulled some market participants in to believing they had no need of such mechanisms. Recognizing the commodity nature of the electricity market and taking appropriate steps to protect against the upside risk is important. Had more market participants done so, it is likely that this summer's price volatility and its impacts would have been moderated. Forward contracting is also a vehicle by which new entrants in the generation market can limit their downside risk, thereby facilitating the development of new generation.

Evaluate the Need and Options for Further Encouraging Generation Development

As noted earlier, the Council's analysis of power supply adequacy indicated that market prices would not be sufficient to support the development of "merchant" power plants, i.e., plants selling into the spot market exclusively, until 2004. The Council has also done analyses looking at actual market prices over the past year to see if prices had been sufficient for a new entrant to cover its variable operating costs and its fixed costs and earn a reasonable rate of return. Until this summer the answer has been "no."

With the electricity and gas prices experienced over the past year, the answer has become "yes." With the higher prices, a couple of plants not considered in the Council's adequacy study have begun construction. In the Northwest, there are now 1,276 MW of capacity under construction that should come on line in 2001 through 2002. There are another 2,977 MW that already have site certificates, 1,291 MW of which we judge to be "active" projects, and another 3060 megawatts that are in or have begun the siting process. The siting process does not appear to be a problem in that there is a backlog of sites that have been permitted and many more in the process. Almost all of these are natural-gas-fired combustion turbines, and nearly all of them are located within reasonable proximity to natural gas pipelines and transmission lines. There is a similar story to be told elsewhere in the West.

The degree of developer activity is encouraging. However, if we were to experience a couple years of relatively warm, wet winters and cool summers with good hydro conditions, market prices would probably fall and many of the active projects might become inactive. If followed by a dry spell and a hot summer or a cold winter, we would be up against the supply limits again.

The question this possibility raises is whether we can rely on the market to provide sufficient capacity for reliability purposes. And if not, what are the options for assuring that there is capacity available to assure reliability and mitigate excessive price spikes? The Council intends to pursue this question.

Accelerate Efforts to Develop the Demand Side of the Market

While the lead time for the development of new combined cycle generation is relatively short, development will take some time. During that time the region and the West are vulnerable to further price spikes and possible reliability problems. Moreover, it is not certain that the long-term market will support the level of development necessary to assure adequate reliability. Developing the demand side of the market has the potential for somewhat shorter lead times. Price responsive demand can help mitigate price spikes and potentially avert reliability problems.

The Northwest has a great deal of successful experience in increasing the efficiency of electricity end-use as a resource. The region needs to reinvigorate those efforts in light of the market prices we are experiencing. There are cost-effective means of slowing the growth of demand that should be exploited. However, the region in particular needs to move aggressively to implement price-responsive demand management – reducing loads during periods of high prices or shifting the loads to periods of the day where prices are less. The bad news is that this region has relatively little experience with these approaches, although that is changing. The good news is that there should be significant untapped potential.

The Council believes that market-like mechanisms wherein the consumer receives a significant part of the benefit will be most effective. Pilot programs have been initiated this year in the region in which the serving utility and the load-reducing consumer share the cost savings of avoided power purchases (or the revenues from selling the freed-up power on the market). These programs appear to have been successful although limited in scope. The greatest potential for such partnerships probably exists within industry and large commercial buildings. What can be done will vary from building to building and process to process. Nevertheless, if provided the incentive, the Council believes people will rise to the challenge. Creating these incentives should be a priority for the utilities of the region.

California Should Correct the Incentives in their Market Structure that Contribute to Excessive Prices and Volatility

The Council believes that the California ISO and others in the California market have done a credible job of identifying the barriers and incentives created by their market structure that have contributed to excessive prices and price volatility. We know the issues are complex and politically volatile. We hope that the state can move quickly to correct these problems.

At Least Until the Market Matures, Data for Monitoring and Evaluating the Performance of the Market Should be Available on a Timely Basis

One thing that the experience of this summer has shown is that it is difficult to obtain the data necessary to monitor and evaluate the performance of the market. Despite the fact that utilities in the Northwest were extremely cooperative, there was a delay of many weeks before the relevant data could be obtained. While the WSCC maintains a data base of generation and transmission loading data, not all generators report to the system and of those that do, the data link is not necessarily carefully maintained. Despite incompleteness data, the WSCC has chosen not to release the information to independent body like the Council, even when the Council agreed to keep the data confidential and to use the data in such a way that individual plants could not be identified. We understand the possible commercial sensitivity of some of this information. We believe, however, that there should be arrangements possible that both protect the commercial value of the information and make it possible for responsible independent parties to evaluate market performance on a timely basis. At least until the market has matured and the public has greater confidence in its operation, this should be a high priority for market participants and organizations like the Western Systems Coordinating Committee, the California ISO and regional transmission organizations as they are formed.

Electricity Emergency Process and Procedures Need to be in Place

If we are correct in our assessment that the electricity market prices experienced this summer are a warning of approaching scarcity, then establishing the processes and procedures that would be used in the event of an actual supply emergency should be a priority. Until new generation comes on line and demand-side programs can be implemented, there is significant probability that our emergency readiness will be tested. Necessary elements include an inventory of the actions that could be taken, the trigger points for taking these actions, clear definition of roles and responsibilities, and a communications plan to inform the public. We are pleased that efforts to accomplish this are underway involving the Pacific Northwest Utilities Conference Committee, the Northwest Power Pool, Bonneville, the Council, the Northwest states and region's individual utilities.