APPENDIX E

AN ANALYSIS OF THE WESTERN POWER MARKET

INTRODUCTION AND SUMMARY

The power market within which the Northwest operates includes all of the West Coast, corresponding to the interconnected systems of the Western Systems Coordinating Council (WSCC). This paper reports on the Northwest Power Planning Council's analysis of a major portion of that market, California and the desert Southwest. The analysis relies on several sources of data and attempts to reconcile them to the extent that they conflict with each other. We have constructed both supply and demand curves for energy from California and the Southwest that are differentiated by season and time of day, but this paper describes only the results of the supply curve analysis. The issues that the paper describes are common to both supply and demand curves.

The analysis generally shows the effects of both a near-term surplus of capacity on the West Coast and the continuing low natural gas prices contained in the Council's latest gas price forecast. This analysis was undertaken to provide additional depth to the evidence available in current offers to buy and sell short- and intermediate-term energy and to explore issues surrounding the development of the western power market.

The analysis indicates that, as might be expected, the price of natural gas is a key determinant of electricity price levels, but that the current surplus in the WSCC region is probably not an overriding consideration except at certain times in certain months of the year. The development of a liquid market with decreasing transmission barriers will likely do much to exploit the value inherent in the seasonal and time-of-day load differences in the West Coast market. The analysis further suggests, however, that utility responses to the air quality problems of Southern California may have a significant effect on the ability to exploit that value.

Description of the Western Power System

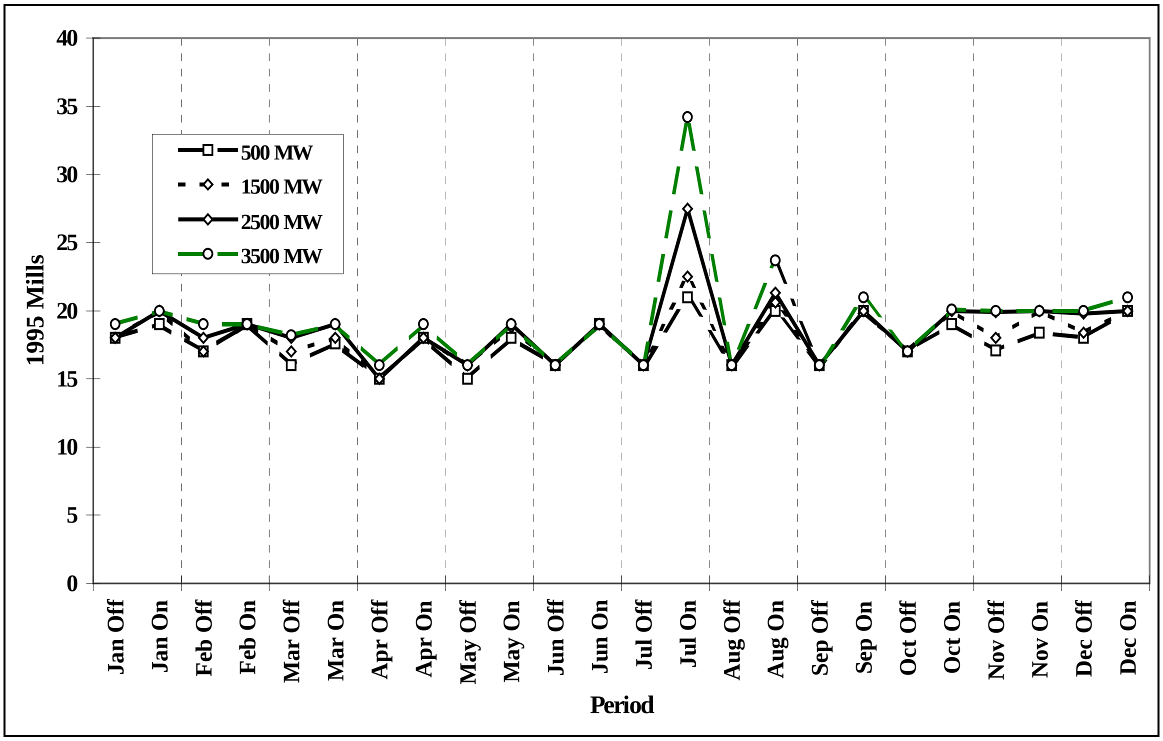
For purposes of comparing costs and prices in wholesale markets, it is useful to think of the West divided into market nodes connected by transmission lines. This is also how the markets that have been developing have characterized the system, and it will be the basis for the financial instruments that are likely to be developed to accompany these commodity markets. For this analysis, four nodes can be identified: three generation nodes, the Inland Southwest, Northern and Southern California, and the Northwest, and a market node at the border between California and the Northwest (usually described as "COB" or "COB/NOB," for California-Oregon Border/Nevada-Oregon Border, the two places the pacific intertie crosses into the Northwest).

Generally in the western market, more nodes than this are identified, but these four are sufficient for the purpose of this analysis. Within each generation node, no transmission limitations are modeled (a problem that is discussed further below) and no transaction costs are identified. These nodes are used to describe the results of the modeling analysis and to check results through comparisons to recent data from the power market.

Results

The results of the study are summarized below. Figure 1 shows the projected range between the costs at the highest and lowest California load periods of the day for 1996. Because the model with which the analysis was done operates with a three-hour time step, the periods are the lowest three-hour period, between midnight and 3:00 a.m. and what is typically the highest three-hour period, between noon and 3:00 in the afternoon. The results of the modeling have been calibrated to current short- to intermediate-term supply offers at the COB market node, so the results in this paper represent potential offer prices at COB. The calibration issues are significant and are discussed further below.

Figure E-1
1996 On- and Off- Peak Prices



The graph shows the range between the lowest and highest load periods of the day by month for four different levels of supply. Each level represents the average price of a 500-megawatt block of power for that hour. Thus, the line labeled "500 MW" shows the average price for the block between 0 and 500 megawatts above the resource required to meet load in California, the block labeled "1500 MW" represents that between 1,000 and 1,500 megawatts, and so forth. The results were cut off at the level of 3,500 megawatts based on judgments about average transmission availability, which is not well represented in the model. In addition, the monthly availability of transmission capability can further limit the results shown in this and following figures, as, for instance, the several-week maintenance outage on the DC intertie, which typically occurs in October.

Figure E-2 displays similar information for the year 2001 and Figure E-3 for 2005. In each of these figures, when the line drops to zero, it indicates that there is no more supply at that level. The prices show some increase over time due to three influences. The first influence is the real increase in natural gas prices over time, averaging 1.7 percent over the period 1995-2015. The second factor is the inclusion of two levels of nitrogen oxides (NOx) emissions allowance costs in 1999 and 2003, which are described below in the discussion on air quality issues. The third factor is a declining resource surplus in the WSCC over the period, which pushes less efficient generating units into the 3,500 megawatt cutoff range, and lower in the case of the peak hours of the year in July through September. The single non-zero point (on the "500 MW" line) for July on-peak in Figure E-3 indicates a surplus in the 0-500 megawatt range, and is a result of approximate system load and resource balance in that hour, which is the annual peak hour in the model.

Figure E-2
2001 On- and Off-Peak Prices with Moderate NO_x Allowance Costs

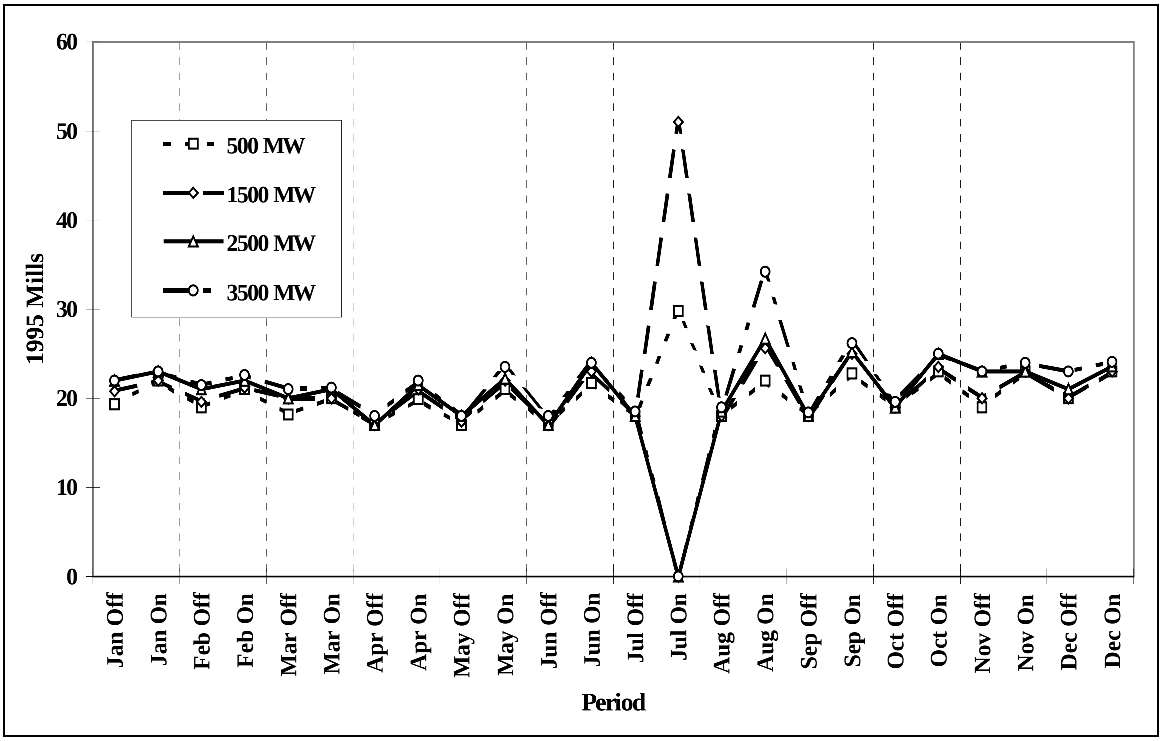
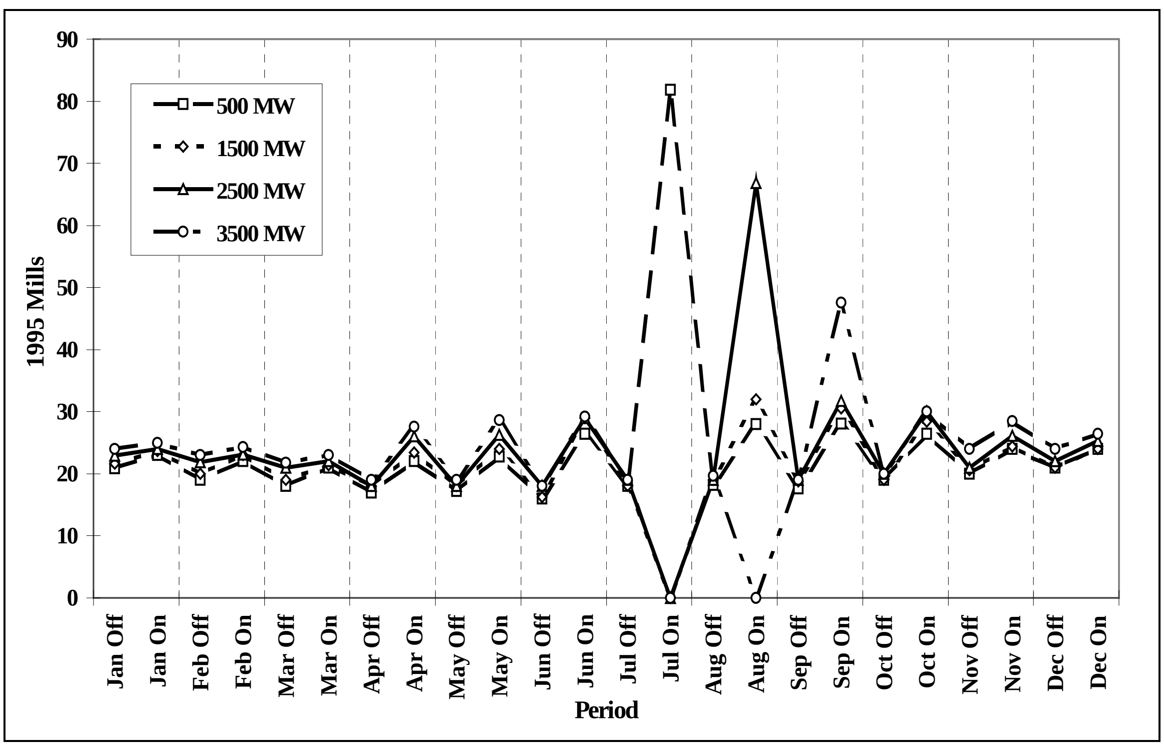


Figure E-3
2005 On-and Off-Peak Prices with Moderate NO_x Allowance Costs



Issues Raised by the Analysis

There are several issues that need to be addressed in evaluating the basic supply curve information described above, including natural gas price and transportation, air quality mitigation costs and related restrictions on plant operations, the extent of the surplus in the WSCC region, capacity expansion and transmission limitations.

Natural Gas Prices

This analysis began with the Council's wellhead natural gas price forecast. This forecast is actually for a delivered-to-pipeline price similar to the price at Henry Hub, which is in turn the delivery point for the New York Mercantile Exchange (NYMEX) futures contract. Thus, it can be compared directly to a NYMEX futures price, published daily for contracts going three years out into the future. The price series used in the analysis, including a calibration factor (discussed below) of $0.10 per million Btu (MMBtu) in 1995 dollars, is shown below in Table E-1. A range of gas prices was used in the analysis, but the results are not described in this paper, which displays only the results of the medium gas price forecast.

Table E-1

California Dispatch Gas Price

California Dispatch Gas Price	
Year	1995 $/MMBtu
1995	1.69
1996	1.74
1997	1.78
1998	1.83
1999	1.87
2000	1.92
2001	1.94
2002	1.97
2003	1.99
2004	2.01
2005	2.03
2006	2.07
2007	2.10
2008	2.14
2009	2.17
2010	2.21
2011	2.24
2012	2.27
2013	2.31
2014	2.34
2015	2.38

Two basic approaches to deriving California electricity prices from national gas prices were possible. The first is a bottom-up approach. This approach starts with the national (Henry Hub) price, estimates the differences (called the "basis") to get to other supply basin prices, estimates the market price of gas transportation, given the active secondary market in discounted gas transportation capacity, takes account of the constraints on the last two factors from local supply and demand conditions, and adds electric transmission charges to a delivery node such as COB. The second approach simply collapses all the intermediate factors into a calibration between a Henry Hub price and an estimate of offered electricity prices at COB.

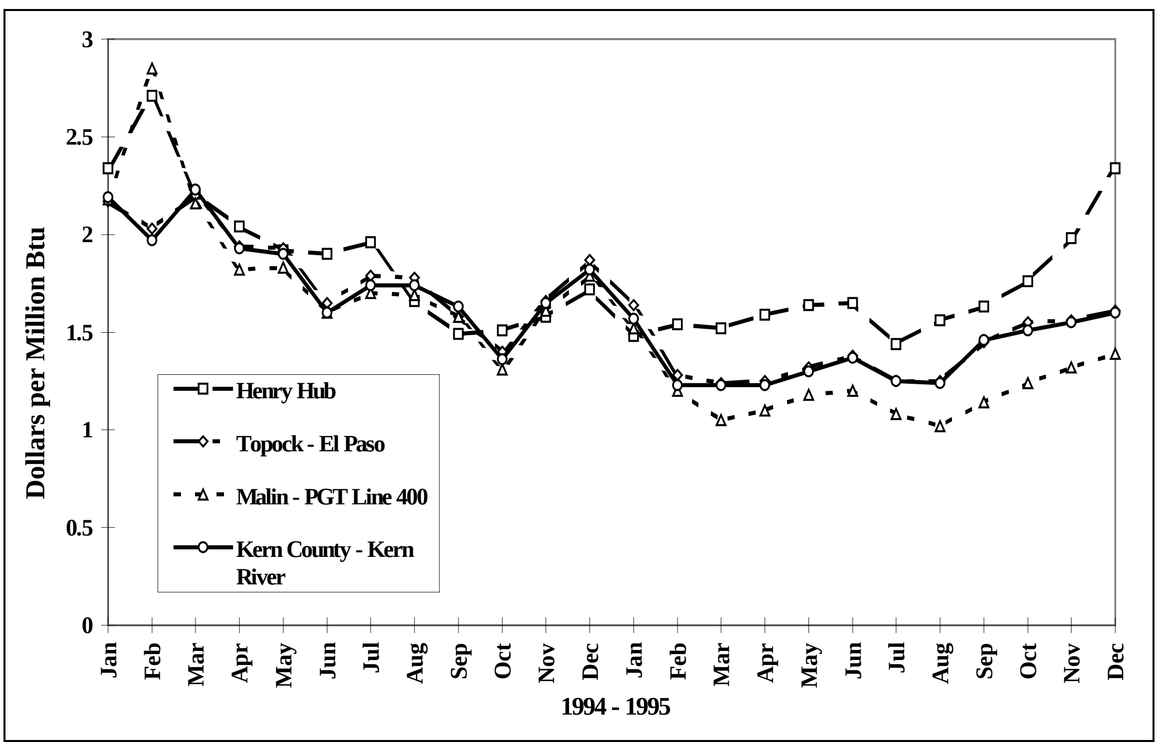
This analysis takes the latter course. The model was calibrated using two factors, both constant in 1995 dollars. The first was an adder of $0.10 per million Btu to the forecast of national gas prices. The second was a factor of 2.5 mills that was added to the operating cost of all California plants that were not operating to meet native load, but could operate for the export market. These factors gave the right relationship between the gas price forecast used in the model, the summer 1995 futures price for winter 1995 gas deliveries at Henry Hub, summer 1995 offer prices for electricity delivered at COB from the south in winter 1995, and the model's calculation of winter 1995 prices in the first block of the calculated supply curve.

The advantage of this approach is that it is both simple and transparent. As market estimates of the Henry Hub monthly price change, as shown by the futures market prices, the estimate of short-term and spot electricity prices would change as well. As the electricity market develops and increases in transparency, the key factors can be adjusted. The obvious disadvantage of this approach is that it locks a current relationship into the analysis, when that relationship may not hold into the future. Moreover, there is limited information available with which to calibrate the model, and the electricity market is still developing. The following paragraphs describe some of the considerations in evaluating this calibration.

The spot California prices for gas delivered to electric utilities in Northern and Southern California are functions of national prices, represented by the Henry Hub price, price differences due to supply and demand at the supply basins serving California, price difference due to supply and demand at the consuming hubs, and pipeline charges for gas transportation among these physical locations. All of these are marketable products, some with futures and futures options prices in the financial markets as well as spot and long-term prices in the physical markets. This is a complex market, even looking at California alone, with gas supplies coming from three major supply basins (Alberta, San Juan, and Permian) and two smaller basins (British Columbia and the Rocky Mountains in Wyoming), directly through four pipelines (El Paso, Transwestern, Kern River, and PGT) with links to a fifth (Northwest) that cross-connects the four pipelines and several of the supply basins.

Figure E-4

Henry Hub vs. California Delivered Prices



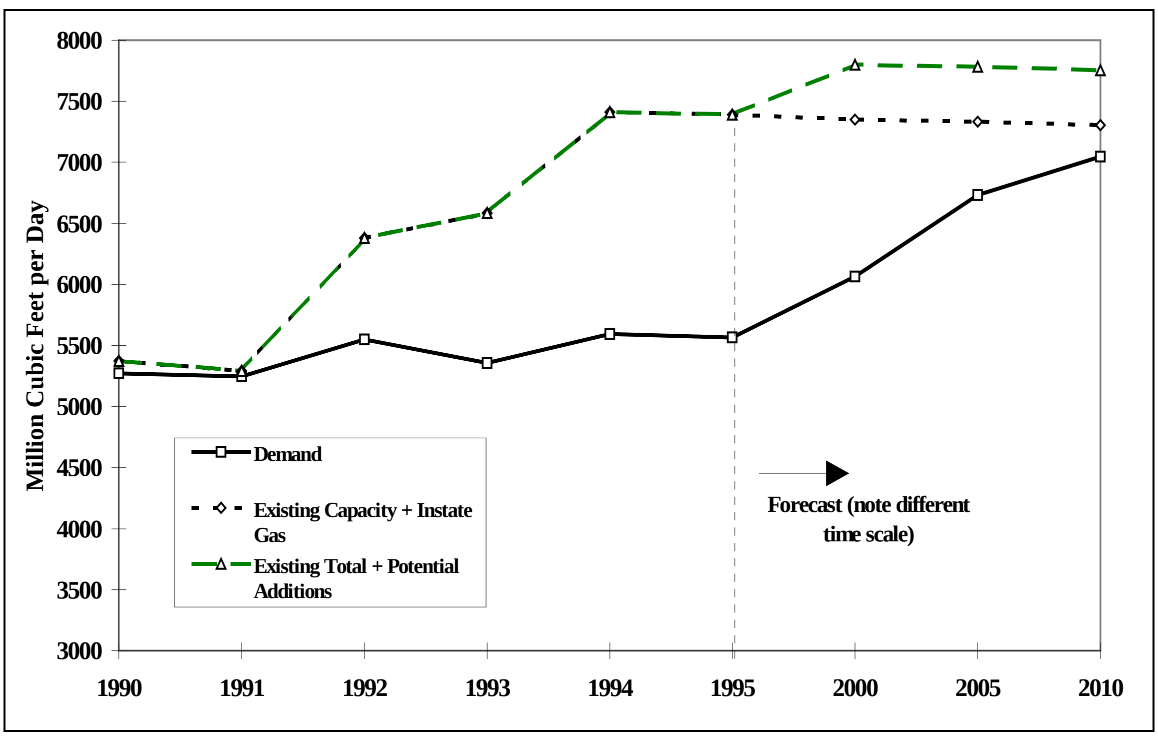
The relationship between Henry Hub prices and gas prices in the basins and pipelines supplying California is dramatically different in 1995 compared to what it was in 1994. This is illustrated in Figure E-4. The figure shows the spot prices at Henry Hub and at three points at which interstate pipelines deliver gas to California (along with the pipeline names). El Paso Pipeline connects the San Juan and Permian basins at Topock, Arizona; PGT connects Alberta at Malin, Oregon; and Kern River Pipeline connects the Rocky Mountain Basin at Kern County, California. (Because of the cross connections of Northwest Pipeline, gas from other basins can also be delivered by these lines at these points.) The calibration is based on 1995 conditions and implies roughly that the intrastate gas transportation cost and any added variable cost of generation and electric transmission to the Northwest border are all offset by lower delivered gas costs at the pipeline and by the calibration factors.

One factor that differentiates the two years in Figure E-4 is the amount of nonfirm energy supplied from the Northwest into California. While 1994 represented a continuation of the long drought in the Northwest, the 1995 runoff was about normal. This would reduce the demand for gas in California by electric utilities and thus lower the price that gas deliveries into California could command.

A second factor is the current substantial excess capacity in the pipelines supplying California markets, estimated to last well into the 2000s. Figure E-5 shows the results of one estimate[1] in million cubic feet per day (MMcfd) of capacity. Note that the horizontal scale contracts in the forecast range of the graph. This suggests that one of the reasons for the current low gas price in California markets is discounting of pipeline charges due to competition both for gas supplies and for interstate pipeline capacity. Based at least on the analysis represented in Figure E-5, the pipeline excess capacity problem is likely to last well into the future. Pipeline capacity owners are trying to turn their capacity rights back to the pipeline owners and the owners are attempting to renegotiate prices. It is difficult to tell how this process will turn out, but it is unlikely to change the physical fact of excess pipeline capacity, which will likely continue to drive spot capacity prices down.

Figure E-5

California Gas Demand and Pipeline Capacity



[1] Data from study by Cambridge Energy Research Associates, published in *Oil and Gas Journal*, September 11, 1995.

Air Quality

Air quality is one of the major issues affecting the California generation market. Some air quality limitations are not easily modeled in this analysis, such as regulations that limit particular plants' total output of some pollutant over a time period. However, one of the biggest problems, NOx in the South Coast Air Basin, is one where the effect can be estimated. The South Coast Air Quality Management District (SCAQMD) has instituted a program of tradable emissions allowances, that will phase in through 2003.

This program (RECLAIM, for Regional Clean Air Incentives Market) initially gives the utilities sufficient allowances so operations of their plants are not expected to be limited. Over the next eight to nine years, the initial free allowances are substantially reduced and the utilities will be required to purchase them from others or reduce the NOx emissions of their plants. Discussions with California Energy Commission staff indicated that Southern California Edison (Edison), for instance, is likely to have insufficient allowances to meet its native load by the early-2000s. The base case values that the Commission will use in its current (1994) Electricity Report analysis are shown in Table E-2 below.

Table E-2

NOx Allowance Price Forecast

Year	1995 $/Ton
1995	745
1996	9,623
1997	11,245
1998	13,305
1999	16,637
2000	21,580
2001	23,487
2002	26,622
2003 on	29,570

This substantial increase in at least one agency's forecast of the cost of RECLAIM allowances (also called trading credits), connected with the decrease in the base levels of allowances over the same period, suggests two potential strategies for the affected utilities. The first strategy would be to minimize the level of outlays to achieve the emissions targets, by retrofitting plants and purchasing only those allowances necessary to continue meeting native load at the lowest cost. This strategy would imply that most sales into the market by South Coast Basin utilities would be limited and subject to potentially high allowance cost adders, even for off-peak sales.

The other strategy would be to participate actively in the western market. This strategy would imply at least some modest level of retrofits to reduce NOx emissions, coupled with some purchases of allowances. The latter seems like the most likely strategy, given several factors. The first is the ongoing deregulation of the generating market, both nationally and specifically in California. Edison, in particular, is an active participant in proposing a restructuring solution to the California Public Utilities Commission that would bring its fossil generation to market value by 2001 and deregulate sales after that. The second factor is that reductions in NOx emission by 70-80 percent over uncontrolled levels can be achieved at a relatively low capital cost.

This analysis assumes that the utilities take the latter path. The results shown earlier include the effect of approximately 4 mills in 1999 and 8 mills in 2003 added to the variable costs of South Coast Basin steam plants to cover the costs of retrofitting and purchasing allowances at the subsequently reduced emissions level. Single-cycle combustion turbines, many of which have relatively poor heat rates to begin with, are not assumed to be retrofitted, since the technology is not applicable and the plants are used primarily for reserves and short-term peaking. The adders on these plants can be substantially higher than for the plants that are assumed to participate in the market.

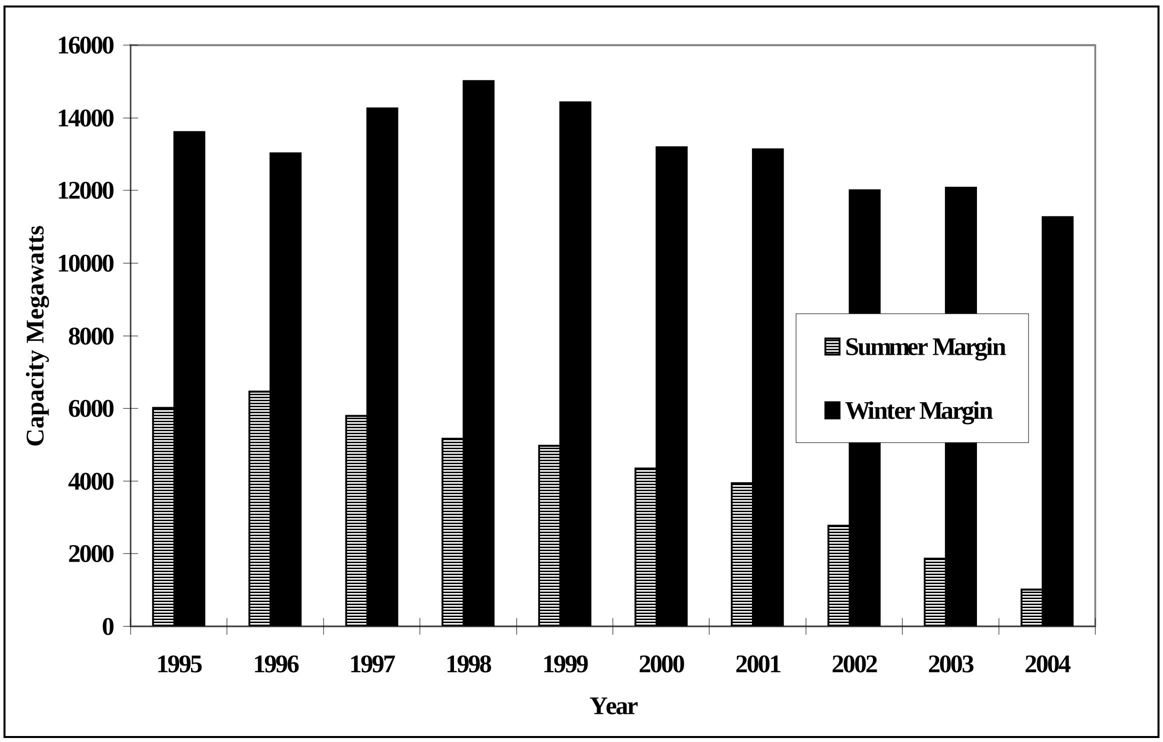
The WSCC Surplus

The current electricity surplus in the WSCC region is approximately 6,000 megawatts, excluding the Northwest Power Pool area.[2] This is calculated on a summer peak basis, since the non-Northwest portion of the WSCC is summer peaking. On a winter peak basis, this same area has approximately a 13,600 megawatts surplus. Both surpluses are in excess of required reserve levels. A good portion of this summer peak surplus, about 3,400 megawatts in California alone, is pumped storage capacity, which is used to level daily and weekly peak loads, and depends on the availability of relatively cheap off-peak generation for its economic operation. Even without taking this into account, however, the surplus described in the WSCC reports is likely to be eliminated in the early- to mid-2000 period by load growth and retirements, with the surplus being eliminated first in the California-Southern Nevada area. The overall WSCC surplus level, net of required reserves, is shown below in Figure E-6. The surplus looking only at the California/Southern Nevada and Arizona/New Mexico areas, which is more limited, is shown in Figure E-6, which also shows the load-resource balance used in the model (ACME). The WSCC areas shown in Figure E-6 correspond more closely to the area that was modeled in the analysis, and Figure E-6 shows the correspondence.

Figure E-6

WSCC Surplus Above Required Reserves

(Excluding Northwest Power Pool Area)



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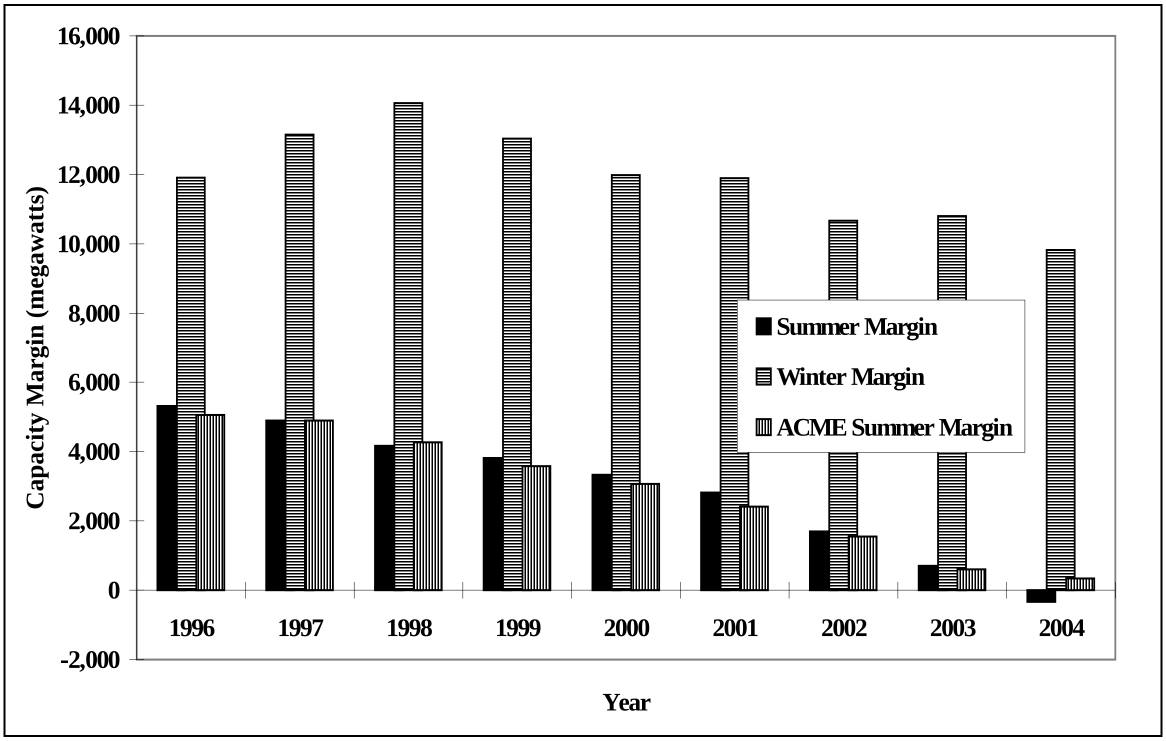
[2] The Northwest Power Pool area includes not only the Northwest as defined by the Northwest Power Act, but also British Columbia, Alberta and Utah, northern Nevada, western Wyoming and most of Montana.

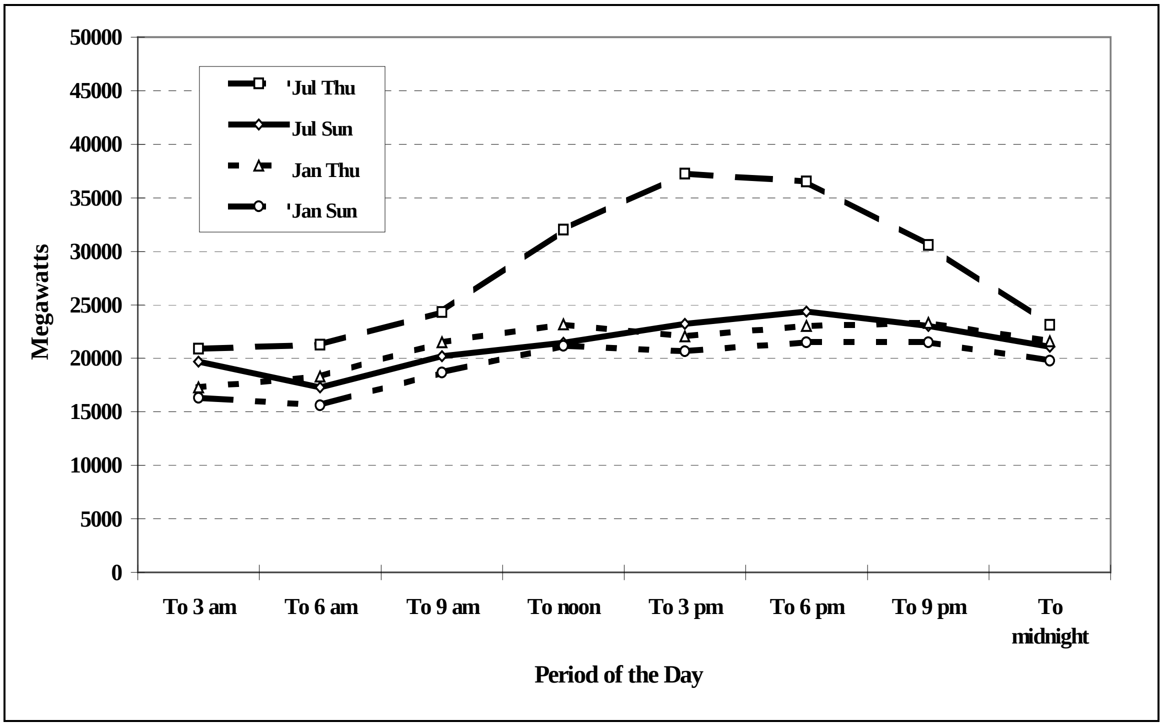
Figure E-7
ACME vs. WSCC Capacity Margin Above Reserves
(Excluding Northwest Power Pool and Rocky Mountain Areas)



The analysis indicates that the potential benefits of the market are not limited by the availability of surplus capacity in the West. Substantial time-of-day and seasonal load variations exist that leave marketable generation available even when there is none during the actual peak hours. This is illustrated in Figure E-8. This graph shows the daily load curves in California as represented in the model used in the analysis. The model uses data with hourly loads aggregated into three-hour segments. This graph shows the net load after the load leveling operation of the Northern California hydropower system, but before two other factors. The first is the application of peaking contracts with the Northwest, which total about 1,800 megawatts in the summer peak hours. The second is the pumped storage operation, which would tend to lower the on-peak loads and raise the corresponding month's off-peak loads (e.g., July Thursday night and all day Sunday) by about 3,400 megawatts. Even with this adjustment, there would still remain a substantial surplus of generating capacity in the July off-peak periods and in all the January periods.

Figure E-8
ACME 1996 Daily California Load Curves

(After hydropower is dispatched)



There are, however, several qualifications to this general assessment. The first has to do with air quality. As discussed above, costs of compliance and/or absolute limitations on emissions may limit off-peak generation in certain air basins, even when capacity is available.

The second limitation has to do with the extent that the California and Southwest utilities depend on the Northwest market to meet their summer peak loads. The data have been adjusted to take into account existing contracts with the Northwest that provide summer peaking resources, but do not account for any future plans to rely on the market to provide summer capacity. The analysis assumes that future peak requirements are met by generation installed in California and the Southwest to meet their peak loads. This suggests that a conservative approach to relying on the market described in this analysis is warranted. Additionally, the generation that was assumed was combined-cycle plants. If single-cycle combustion turbines were part of the mix of additional generation, it might raise the prices for daytime peak hours during the off-peak months, because those are the periods in which new combined-cycle generation would tend to displace older steam plants with somewhat higher heat rates. It would probably not affect the absolute peak day prices because loads in those hours would continue to be met with older, even less efficient single-cycle plants.

Capacity Expansion

A further effect of the assumption that California and Southwest generation is installed to meet native loads is that the results described here do not directly show the effect on prices of impending capacity expansion requirements. In a commodity market, one would expect longer-term cycles of high and low prices corresponding to capacity expansion cycles. In this analysis, the market is brought to equilibrium and maintained there, corresponding to the way traditional utility planning was supposed to work. The high prices that show up in the peak periods of the summer months of 2005, for instance, as shown in Figure E-3, reflect the operation of single-cycle combustion turbines with poor heat rates burning distillate fuel. These are the kinds of high prices that would elicit further investment from a generation market, but that has not been explicitly modeled or evaluated. So the timing of these high prices over the capacity expansion cycle and the effect on prices in other hours is uncertain. The Council will explore this issue further in the future.

Transmission

California is not a single market, although it is modeled that way for this analysis. This limitation needs to be kept in mind in evaluating the results presented here. The Northwest is currently connected to California and the Inland Southwest by two major interties, the AC Intertie to Northern, and to a lesser extent, Southern California, and the DC Intertie directly to Southern California. Southern California is in turn connected to the Inland Southwest, the site of large portions of its own generation, by 500 KV lines. Nonetheless, transmission is more likely than generation availability to limit the ability to import into the Northwest, and generally to limit the emerging power market. In particular, the ability to import from the Southwest and Southern California to Northern California on the AC Intertie can be limited to as little as 1,300 megawatts under some load and generation patterns. Light load hours together with full Diablo Canyon plant operation yield the lowest transfer capability.

While the AC Intertie capability from Northern California into the Northwest is approximately 3,700 MW, generation availability in Northern California is typically far less, except during good runoff conditions in the spring, when it would primarily represent competition for sales from the Northwest rather than purchase opportunities.

The DC Intertie can generally be loaded to its full rating, approximately 2,900 MW south-to-north, simultaneously with an almost-full loading of the AC Intertie into the Northwest from Northern California, without impinging on reliability criteria based on the stability of the transmission system. However, heavy and long-term reliance on imports on the DC Intertie, a single line in a single right of way, to meet loads could incur the risk of not having an alternative contractual pathway in the event of an outage on the DC line. In the event of an outage, the remaining system would have new, lower stability ratings that would have to be met by reduced transfers within a very short time. In recent years, prolonged outages have occurred because of a fire and an earthquake in Southern California. An additional high voltage line, the Southwest Intertie Project, connecting the Southwest with the Northwest, is in the advanced subscription stage, which would likely mitigate some of these concerns. That line is indicated in current WSCC documents as planned for service in 1999. These considerations argue for conservatism in reliance on long-distance firm imports.

THE EVOLVING WESTERN POWER MARKET

Currently, the Federal Energy Regulatory Commission (FERC) regulates the prices of wholesale power transactions by investor-owned utilities. It has recently declared that the generation market is sufficiently competitive that it need no longer regulate the wholesale prices of generation from new power plants. In its Notice of Proposed Rulemaking on open access transmission (RM95-8-000), FERC indicated that it will evaluate the question whether the open transmission access proposals it is making eliminate enough remaining monopoly power over generation that it could declare that generation from existing power plants need no longer be regulated, as well.

This market is rapidly evolving toward a highly competitive commodity market. It was traditionally characterized chiefly by economy or nonfirm energy transactions between utilities trying to minimize the cost of operating their own generation to meet franchise loads. In the last few years, this market has seen the emergence of power marketers, who buy, repackage and resell electricity in the wholesale market; power brokers, who bring parties together but do not own or contract for generation; and financial products to help manage the risk of such transactions. These changes, combined with the continuing strength of large-scale non-utility generation developers, are being facilitated by development of procedures for opening access to utility transmission systems.

The New York Mercantile Exchange (NYMEX) has recently applied to the Commodity Futures Trading Commission (CFTC), a federal regulatory agency, for permission to offer two electricity futures contracts, with delivery points at the California-Oregon border (COB) on the AC Intertie and at the Palo Verde nuclear plant switchyard in Arizona. Since mid-summer 1995, an index of on- and off-peak nonfirm energy prices at COB has been published daily in *The Wall Street Journal*, and other publications and subscription services have started providing spot and longer-term power market quotes at several locations in the West where trading can occur because of accessibility to multiple providers. Exchange-traded futures contracts and, most likely, subsequent options on futures contracts, both building on these publicly available indexes, will provide means to manage the price volatility in short- and intermediate-term markets. Such contracts are likely enhance the level of activity in the power market substantially, if the experience in the natural gas industry is a guide.

The maximum term of the proposed futures contracts is likely to depend on market demand. The NYMEX natural gas contract was originally for a maximum term of 18 months, but was just recently extended to 36 months. Longer-term contracts are available in off-exchange markets, but they lack the financial backing of an exchange-traded contract. The ability to manage price risk over longer periods will thus depend in part on knowledge of the characteristics of the physical market and reliance on the financial strength of the direct counterparty to the contract because the financial assets of an exchange are involved in over-the-counter markets.

Method and Data Issues

This analysis was done with a model called ACME (Accelerated California Market Estimator), developed by the Bonneville Power Administration to estimate the demand in California for nonfirm energy from the Northwest. The model has been modified so that it can also be used to develop estimates of the amount of energy that could be supplied from California to the Northwest. The model operates in three-hour periods over a typical week in each month. It operates with two basic subregions of the west, California and the Inland Southwest, including the southern Rocky Mountain area, connected by transmission interties. There are no transmission or other limitations represented between Northern and Southern California, and all California resources are dispatched to meet all California loads. This aggregation of California loads represents one of the most important limitations on the current version of the model.

In each region, the model commits resources to meet weekly peak native loads, dispatches resources to meet the period-by-period loads and then makes further economic imports from the Southwest into California. The net California resources, as dispatched to meet California loads and limited by any minimum generation constraints, constitute the demand curve for sales of Northwest energy. To develop the supply curve, all additional California units that are either in excess of or too expensive to run for California loads are added up. In either case, the Inland Southwest resources are only seen by the Northwest through their effect on California resources. There is no direct connection in the model from the Northwest to the Southwest.

The California plant data in the model were updated to use average incremental heat rates for operating levels between 50 percent and about 80 percent of full load. The values were derived from data in the California Energy Commission’s data set for the draft 1994 Electricity Report, which came out in the summer of 1995. These heat rates are typically lower (representing more efficient operation) than average heat rates at full load operation. California loads were updated using the Commission’s draft report as well. Arizona and New Mexico data were updated to the levels in the WSCC 1995 Bulk Power Supply Program.

Generating plants are aggregated by operating cost into categories that are 1 mill apart. The plants’ capacities are based on levels derated for the expected forced outage rate of the plant. The model does not operate probabilistically. This means, for instance, that a 100-megawatt plant with a forced outage rate of 15 percent, is dispatched as if it were an 85-megawatt plant in all the months in which it is not on maintenance, rather than being dispatched as a 100-megawatt plant with an 85 percent probability and a 0-megawatt plant with a 15 percent probability.

Only one water condition, currently average water, can be represented in the model at a time. Northern California has a significant amount of hydropower, so this has an important effect in limiting the variability of the results of the model. While the model dynamically shapes the hydropower output within limits to meet daily load patterns, the monthly pattern is fixed in the data.

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