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Possible Effects of Competition on Electricity Consumers in the Pacific Northwest

Stan Hadley
Eric Hirst

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POSSIBLE EFFECTS OF COMPETITION ON ELECTRICITY CONSUMERS IN THE PACIFIC NORTHWEST

STAN HADLEY and ERIC HIRST

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SUMMARY

In part, the impetus for restructuring the U.S. electricity industry stems from the large regional disparities in electricity prices. Indeed, industry reforms are moving most rapidly in high-cost states, such as California and those in the Northeast. Legislators, regulators, and many others in states that enjoy low electricity prices, on the other hand, ask whether increased competition will benefit consumers in their states.

This report quantifies the effects of increased competition on electricity consumers and producers in two regions, the Pacific Northwest and California. California's generating costs are roughly double those of the Northwest. We use a new strategic-planning model called Oak Ridge Competitive Electricity Dispatch (ORCED) to conduct these analyses. Specifically, we analyzed four cases: a pre-competition base case intended to represent conditions as they might exist under current regulation in the year 2000, a post-competition case in which customer loads and load shapes respond to real-time electricity pricing, a sensitivity case in which natural-gas prices are 20% higher than in the base case, and a sensitivity case in which the hydroelectric output in the Northwest is 20% less than in the base case.

The ORCED analyses suggest that, absent regulatory intervention, retail competition would increase profits for producers in the Northwest and lower prices for consumers in California at the expense of consumers in the Northwest and producers in California (Fig. S-1). However, state regulators may be able to capture some or all of the increased profits and use them to lower electricity prices in the low-cost region. Perhaps the most straightforward way to allocate the costs and benefits to retail customers is through development of transition-cost charges or credits. With this option, the consumers in both regions can benefit from competition.

The magnitude and even direction of bulk-power trading between regions depends strongly on the amount of hydroelectric power and energy available in the Northwest. Market prices respond much more strongly to changes in natural-gas prices and hydro output than do regulated prices. Indeed, market prices are intended to closely track changes in marginal costs, while regulated prices typically track changes in average cost.

The bottom line from this analysis is that increased competition *can* benefit retail customers in high-cost regions without harming customers in low-cost regions. Such a desirable outcome, however, is not automatic. State regulators may have to intervene to be sure that what would otherwise be additional profits for the producers in the low-cost region are used to lower prices to retail customers.

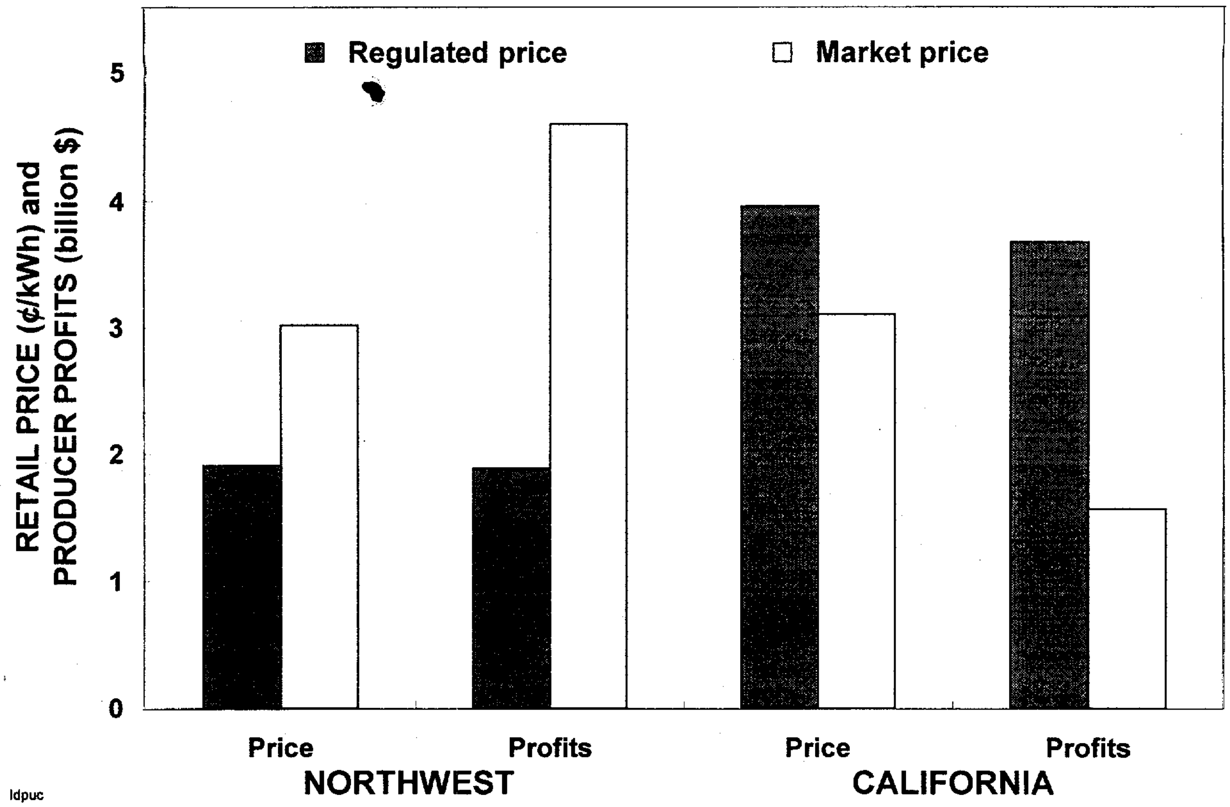

Fig. S-1. Post-competition retail electricity prices and producer profits in the Pacific Northwest and California for the year 2000.

LIST OF ACRONYMS

EIA	Energy Information Administration
ORCED	Oak Ridge Competitive Electricity Dispatch model
ORFIN	Oak Ridge Financial Model
O&M	Operations and maintenance
PUC	Public utility commission
RTP	Real-time pricing
TC	Transition cost

BACKGROUND

The U.S. electricity industry is undergoing rapid and substantial changes. The key manifestations of these changes are (1) much greater competition and trading in bulk-power (roughly speaking, wholesale) markets and (2) the beginnings of retail competition.

Consumers and regulators in states that now enjoy low-cost electricity worry that increased competition may benefit customers in high-cost areas but will hurt those in low-cost regions. For example, the Idaho Public Utilities Commission (1996) stated:

> We are convinced that we should be cautious, however, with respect to an outright deregulation of Idaho's electric markets for several reasons. First, customers of Idaho's regulated electric utilities, on the average, currently pay some of the lowest electric rates in the nation. While some of Idaho's larger customers may be able to obtain lower rates through contract sales with other energy suppliers due to their size and buying power, we find that there is evidence suggesting that the majority of Idaho's ratepayers may experience an increase in rates over the long term. This is simply because, region-wide, and on the average, rates for comparable services outside Idaho are higher. Thus, in a completely free market, Idaho's regulated utilities could find customers in other states who are willing to pay rates that are considerably higher than those currently paid by Idaho consumers. Without adequate oversight, Idaho customers could be required to compete with others for low cost hydroelectricity produced now for the benefit of Idaho customers. Under such a scenario, smaller customers could see their electric rates increase as a result of competition.

This refrain—"retail choice is a threat to customers that will increase electric rates"—is not unique to Idaho (Kemezis 1997). Some utilities, consumer groups, state legislatures, and regulators, especially in states that now have low electricity prices, argue for a go-slow approach to increased competition.

On the other hand, Costello (1997) argues that:

> The protectionist policy now advocated in some states ignores the fact that the trading of a low-cost product or service—whether electricity, wheat, or computer technology (and whether between states, countries, or regions)—will inevitably promote the economic well being of the trading locality. To restrict the export of a given resource (to reserve it for local consumers, for example) is to presume that some consumers are entitled to a subsidy. A subsidy exists

because consumers are paying less for the resource than they would in an open market. No logical reason can explain why certain consumers in a well-functioning market should claim priority over others.

In principle, increased bulk-power trading among regions should lower the total costs to produce and deliver electricity to consumers. Thus, the concern raised in the low-cost states is less about economic efficiency and more about equity (who gains and who loses). If fully competitive electricity markets develop and electricity costs decline, it should be possible to provide benefits to consumers in both low-cost and high-cost areas. Similarly, competition among suppliers for retail customers (i.e., retail choice) should improve economic efficiency. The more-accurate price signals associated with such unbundling and choice should encourage suppliers to produce only those products and services that they can produce at a profit and should encourage consumers to buy only those products and services for which the value exceeds the price. Here, too, it should be possible to provide benefits to consumers in both areas.

The purpose of this analysis is to examine this low-cost vs high-cost issue quantitatively. We emphasize the word quantitatively because the arguments, both pro and con, that we have seen on this issue to date have been largely abstract. No one engaged in the debates over retail competition and its effects on electricity prices in different regions has offered much evidence—data and analysis—to support its view. [A notable exception is a recent study conducted by the Energy Information Administration (EIA 1997), which estimated the effects of competition on electricity prices in 13 regions.] In response to a request from the Idaho Public Utilities Commission (PUC), we focus on the Pacific Northwest and California as the two regions of interest here. Idaho, with its large supply of hydroelectric resources, is a very low-cost state. Its PUC is, therefore, concerned about the possible adverse effects of competition on the prices that Idaho consumers might pay in the future.

ANALYTICAL FOUNDATION

COMPUTER MODEL

We used a new model developed at Oak Ridge National Laboratory to conduct this analysis. The model, developed primarily with support from the U.S. Environmental Protection Agency, is called Oak Ridge Competitive Electricity Dispatch (ORCED). It dispatches generation (the output available from 26 power plants) to meet loads in two regions for a particular year, 2000 in this analysis. (See Appendix A for additional detail on the structure and operation of ORCED.) The two regions are connected by a single transmission link that is characterized by its capacity (MW), costs (¢/kWh), and losses (percentage of throughput). The loads in each region are represented by load-duration curves for two seasons each year.

Although this spreadsheet model is a simple one, it captures the key features of the U.S. electricity system as it might function with competitive bulk-power markets. In particular, generating units bid their variable costs [the sum of fuel costs plus variable operations and maintenance (O&M) costs] into a market; the market selects the cheapest units to meet demand during each time period. All generators are paid the same price during each time period, the price bid by the highest-cost unit then operating. The markets in the two regions interact during each time period such that the outputs from units in the low-cost region are increased and the outputs from units in the high-cost region are decreased until an equilibrium is reached. This equilibrium is determined by the transmission capacity, costs, and losses between the two regions as well as by the generating units online and customer loads in the two regions. If the transmission capacity between the two regions is infinite and if transmission costs and losses are zero, then the two regions operate as one, and hourly spot prices are the same in both regions.

Although less detailed, the structure of our model is similar to the one used by EIA (1997) in its analysis of the effects of competition on retail electricity prices. Both models determine time-varying competitive prices primarily on the basis of the variable cost of the most expensive generator running at that time. (EIA includes certain administrative and general costs as well as taxes in its definition of "variable" costs; we exclude these costs and taxes.) Both models explicitly account for the effects of reliability on prices, especially during those few hours a year when available supplies are not enough to meet unconstrained demand. And both models treat consumer responses to changes in overall and real-time (i.e., spot) electricity prices.

Because ORCED dispatches generators against load-duration curves rather than against chronological loads, some opportunities for trade between regions are not captured by the model. In particular, ORCED, because of the averaging process inherent in load-duration curves, ignores times when forced outages in one region or unusual load differences between the two regions provide opportunities for profitable trades. Also, the model's treatment of only two regions connected by a single transmission link (rather than several regions connected by many links) limits bulk-power transactions. Finally, ORCED cannot account for intraregion transmission constraints that require some uneconomic dispatch of generating units. For example, substantial power flows occur between the eastern and western portions of the Northwest Power Pool, assumed in ORCED to always be unconstrained.

INPUT DATA

We began the present analysis by creating a data set that conforms closely to the year-2000 values of electricity demand, supply, generation mix, costs, and prices that characterize the Pacific Northwest and California/Southern Nevada electricity markets.* We obtained these data from the EIA and Resource Data International PowerDat databases. EIA's database includes its *Annual Energy Outlook 1997* (EIA 1996) plus much of the Federal Energy Regulatory Commission's Form 1 data; Appendix B explains the data sources and approximations used to create the data sets for these two regions. The Pacific Northwest is a low-cost region primarily because of its large base of hydroelectric resources, much of which is owned and operated by the Federal Government and marketed by the Bonneville Power Administration. California, on the other hand, is a high-cost region, primarily because of the many gas- and oil-fired generators in the state.#

The Pacific Northwest has production costs much lower than does California. In addition, because hydroelectric facilities are energy constrained rather than capacity constrained, the Northwest has substantial unused generating capacity, the output of which is often sold to California. Figure 1 shows marginal production costs (the determinant of spot prices) in the two regions.

To simplify the analysis and interpretation of results, we assumed that the only new generating units to be built between 1995 and 2000 were those identified by the EIA (primarily, combined-cycle units, combustion turbines, and small hydro). We also assumed no

*The Pacific Northwest includes all of Washington, Oregon, Idaho, and Utah as well as western Montana and parts of Nevada and Wyoming (i.e., the U.S. portion of the Northwest Power Pool). The California region includes all of California plus the Nevada Power portion of southern Nevada.

#We focus here on variable production costs because generators compete with each other in bulk-power markets on that basis and only on that basis. Fixed costs (fixed O&M costs plus capital costs) affect generator profitability but not the competitive status of generators. Although California's nuclear plants are expensive on a full-cost basis, their variable costs are low.

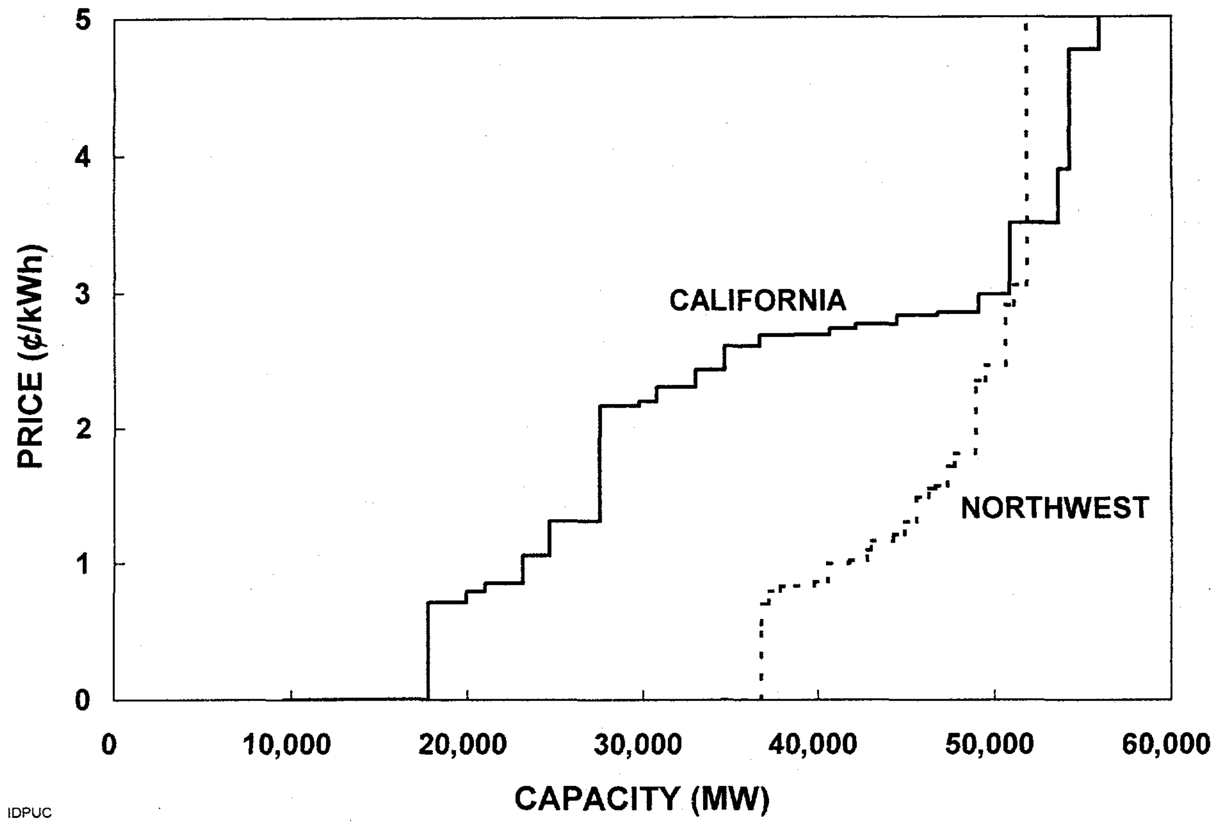

Fig. 1. **Variable costs of electricity production in California and the Pacific Northwest as functions of generating capacity in each region. The nearly 18,000 MW with zero price in California reflect the state's hydro and qualifying-facility capacity. The 36,000 MW with zero price in the Northwest reflect primarily that region's hydro capacity. In both cases, these generators are treated as must-run units in ORCED.**

competition-induced reductions in O&M costs or in generating-unit performance (e.g., lower heat rates and higher availability factors). Finally, ORCED treats generation costs and prices only; the results presented here exclude transmission and distribution costs.

PRICES AND COSTS

ORCED produces several sets of numbers on the prices and costs of generation services, reflecting the perspectives of power producers and consumers, under both traditional regulation (full-cost recovery) and competitive-market conditions. These variables (all expressed in ¢/kWh) include:

Market Price: the annual average price (weighted by consumption) that customers would face if they purchased all their energy from the hourly spot market (Fig. 2). As trading between the two regions increases (e.g., as transmission capacity increases or changes in customer load shapes free up generating and transmission capacity), the market prices in the two regions

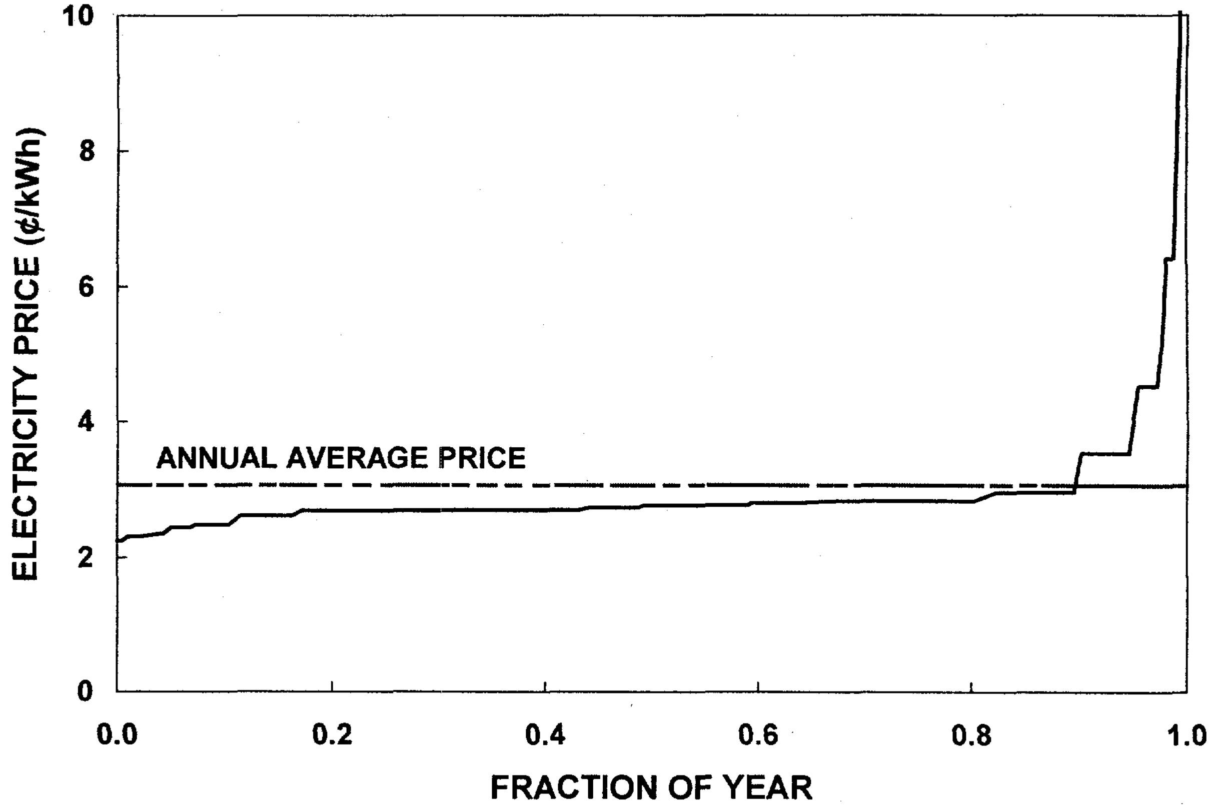

Fig. 2. Market price in California and the Pacific Northwest. Prices exceed 8¢/kWh for 1% of the hours and exceed 20¢/kWh for 0.5% of the hours.

approach each other. At the limit, where trading is completely unrestricted and cost free, the hourly market prices are identical. The market prices, averaged over the course of a year, will differ to the extent that load shapes differ between the two regions.

Market Price Adjusted for Transition Costs (TCs): the sum of market price plus TCs. TCs* are calculated for each generator as the minimum of (a) the generator's unavoidable fixed costs or (b) the difference between revenue and total cost (both expressed in millions of dollars a year). Thus, if revenues exceed the sum of fuel costs, variable O&M costs, and avoidable fixed costs, the "excess" is used to offset some of the unavoidable fixed cost in computing TCs. On the other hand, if revenues do not exceed the sum of fuel, variable, and avoidable fixed costs, the unit should probably be shut down, and TC is capped at the unit's unavoidable fixed cost. If revenues exceed total costs, this "excess" is considered negative TC and is credited to retail customers. The TC adjustment is equal to the total dollar value of TCs for the year in question

*Roughly speaking, TCs reflect the differences between the regulated prices for electricity generation and the prices that might occur in fully competitive power markets. These costs can include generating assets, long-term power-purchase contracts, and regulatory assets (Baxter, Hirst, and Hadley 1997). TCs can be positive or negative. The present analysis does not consider regulatory assets, which leads to an underestimate of TCs in California and an overestimate of negative TCs in the Northwest.

normalized by total retail electricity sales (¢/kWh) and is added to the market price for every hour of the year.

Full-Cost-Based Price: the price calculated from the ratio of total revenue requirement (which includes variable and startup costs, net power-purchase costs, avoidable fixed O&M costs, plus unavoidable capital costs) to total retail sales. This number is the price that customers would pay if the state PUC continues to regulate utilities as it has in the past. Any excess revenues from wholesale sales relative to wholesale purchases are treated as a revenue credit and used to reduce the price charged to retail customers.

Producer Price: the annual average price (weighted by production) that producers would receive if they sold all their energy into the hourly spot market. When there is no trading between the two regions, the market and producer prices are identical. The slight difference sometimes seen in model results is a consequence of the model's treatment of unserved energy, which yields a value for generation slightly different from the value for consumption.

Producer Costs: the production expenses, which include three components (all measured in millions of dollars per year):

- Variable plus startup costs are the fully avoidable variable costs associated with running generators, including fuel plus the variable portion of O&M costs. As trading between the two regions increases, variable costs per kilowatt-hour in the low-cost region increase (because it is producing additional electricity from units with higher variable costs for export to the high-cost region), and variable costs per kilowatt-hour in the high-cost region decrease.

- Avoidable fixed costs include the remainder of O&M costs. As trading between the two regions increases, the per-kilowatt-hour value of these costs decreases in the low-cost region (because these fixed costs are spread among more kilowatt-hours of electricity production) and increases in the high-cost region.

- Unavoidable fixed costs are those associated with the plant's capital costs, including depreciation, taxes, interest payment on bonds, and return on equity. As trading between the two regions increases, the per-kilowatt-hour value of these costs decreases in the low-cost region (for the same reason that avoidable fixed costs decrease) and increases in the high-cost region.

The sum of these three components equals total producer costs. And the ratio of this total cost to total sales is the producer price noted above. (With trade, producer sales in one region do not necessarily equal consumer purchases in that region.)

RESULTS

We used ORCED to analyze two scenarios:

- Pre-competition (base) case: the situation just before retail competition occurs, a time when retail electricity prices are fully regulated and bulk-power trading occurs between the two regions as it currently does. This case is equivalent to current conditions projected to the year 2000.

- Post-competition case: the situation after competition begins, when earnings and retail prices may no longer be regulated. In this situation, customer load levels and load shapes have responded to changes in overall electricity prices and real-time pricing (RTP), and suppliers have retired generating units that are unable to recover their avoidable fixed costs in competitive generation markets.

We also ran sensitivity cases to see how bulk-power trading between, and retail prices in, the two regions vary with changes in the amount of hydroelectric resources in the Northwest and changes in natural-gas prices. We considered assessment of a variety of factors related to transmission capacity, costs, and losses between the two regions; fuel prices; and the amount of hydroelectric output in the Northwest. Based on discussions with staff at the Idaho PUC, we focus on two factors: the price of natural gas (because gas-fired generation sets the market price for many hours) and the amount of hydroelectricity produced in the Northwest (because this is the source of the low-cost power in that region). We decided not to conduct sensitivity analysis for changes in transmission capacity, costs, or losses because we already set these ORCED inputs to maximize electricity flows between the two regions and, as explained above, ORCED results underpredict the amount of trading between the two regions.

BASE CASE

In this pre-competition (i.e., current state regulation) case, electricity consumption is slightly lower in the Northwest than in California (243 vs 250 thousand GWh for the year 2000). Demand in the Northwest peaks in the winter at almost 40,000 MW, while demand in California peaks in the summer at 48,000 MW (Table 1). (The California peak is actually higher, but is lowered in ORCED to account for imports from the desert southwest and other regions besides the Pacific Northwest.)

Variable production costs are almost 1.2¢/kWh lower in the Pacific Northwest than in California. Total production costs (essentially equal to retail-customer prices for generation) are 2.1¢/kWh lower. The hourly spot prices of electricity in the two regions are the same because of our assumption that there are no transmission costs or losses between the two regions. The annual market prices differ solely because the load shapes are different in the two regions, with the Pacific Northwest having a higher load factor than California (69% vs 59%); see Fig. 3. The regulated price of electricity is about 2¢/kWh lower in the Northwest than in California.

The Pacific Northwest generators have a negative transition cost of $2.7 billion a year. In other words, the aggregate market value of these generators substantially exceeds the aggregate book value. The California generators, on the other hand, have an annual transition cost of $2.1 billion. The California Energy Commission (1997) estimates the net present value of TCs at almost $33 billion, equivalent to about $3 billion a year if spread over ten years.*

Table 1. Year-2000 base-case conditions in the Pacific Northwest and California[a]

Factor	Pacific Northwest	California
Consumption and production		
Peak demand (MW)	40,000 (Winter)	48,400 (Summer)
Consumption (GWh)	242,800	250,100
Generating capacity (MW)	52,100	56,800
Production (GWh)	259,800	233,100
Reserve margin (%)	30	17
Generation costs and prices (¢/kWh)		
Variable cost	0.75	1.92
Total production cost	1.98	4.03
Market price	3.02	3.11
Market price + transition cost[b]	1.91	3.93
Regulated price	1.91	3.96

[a]See Appendix Table C-1 for additional details on this case.

[b]Transition costs do not apply to the base case. The numbers shown here are the TCs that would occur if all retail customers paid only market prices for their generation services.

*Our estimate of California TCs is low because our analysis excludes regulatory assets and does not count all the costs of California's high-cost nuclear units and qualifying facilities.

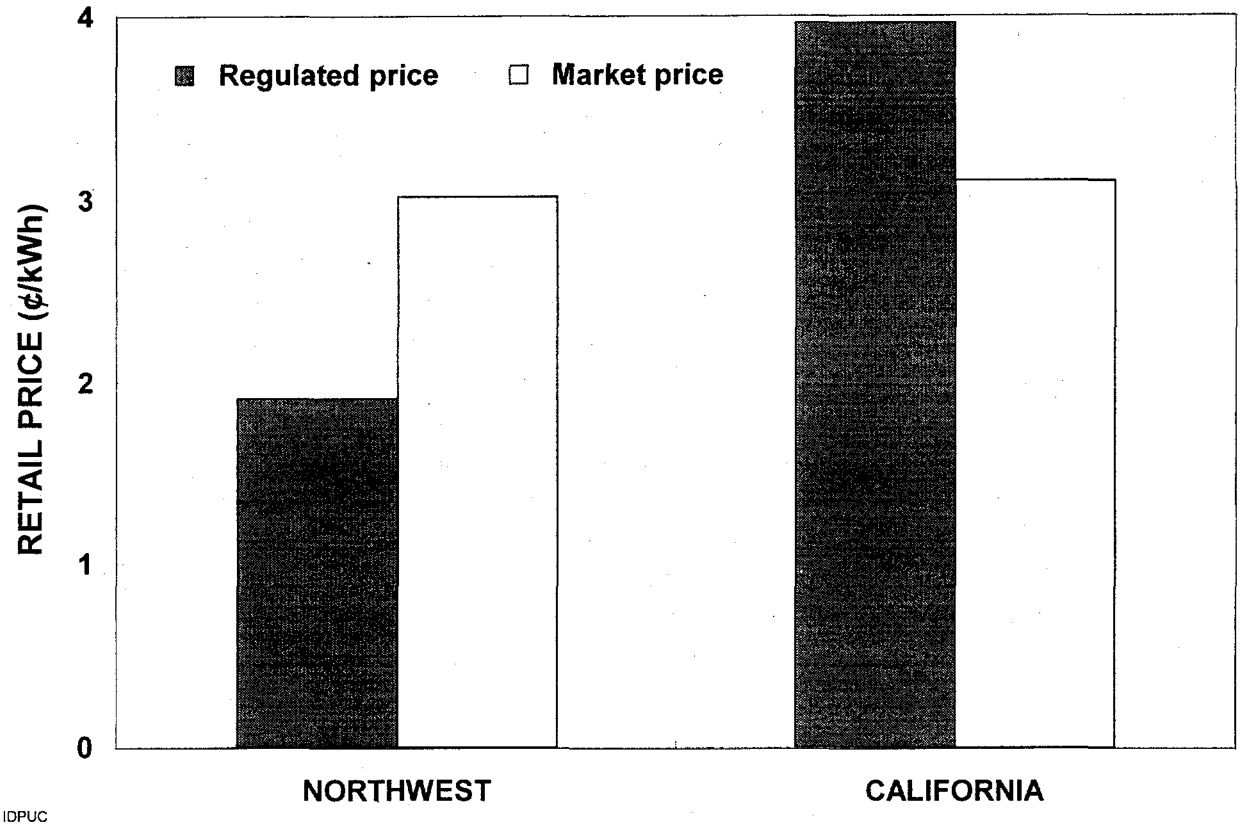

Fig. 3. Regulated and market prices for the year-2000 base case.

As expected, producers in the Pacific Northwest sell substantial electricity to customers in California. The sales from the Northwest to California amount to 7.1% of the electricity consumption in the Northwest. Because of the many low-cost generating units in the Pacific Northwest, the vast majority of the flows are from the Northwest to California; specifically, sales from the Northwest to California total 17,300 GWh, while sales from California to the Northwest total 200 GWh in 2000. Because the California units are higher in cost, they generally set the market price of electricity, as shown in Fig. 1.

According to EIA's analysis, Northwest sales to California for the year 2000 total 22,000 GWh (Church 1997; EIA 1997), 27% more than the ORCED number. ORCED's temporal limitations (i.e., its use of load-duration curves for two seasons rather than chronological dispatch) average away and therefore mask some of the hour-to-hour differences in loads between the two regions and the associated opportunities for trades in both directions. Also, California is summer peaking, and the Northwest is winter peaking; ORCED schedules all maintenance outages in the "offpeak" season, which for purposes of this analysis, is the nine-month period from January through May plus September through December. As a consequence, some Northwest units are not available in ORCED to sell to California in the late spring and early fall. Because of these limitations, ORCED runs the California gas plants at higher capacity factors to make up for the import "deficiency."

POST-COMPETITION CASE

The post-competition case differs from the base case in two ways. First, customers are assumed to face RTP and to adjust their time-of-use demands accordingly.* That is, customers cut demands during high-price periods and increase consumption during low-price periods, which leads to a higher load factor. Also, if overall prices go up or down, overall demand will go down or up. Second, suppliers, no longer operating under an embedded-cost-recovery regime, retire those generating units that are unable to produce sufficient revenues to cover both variable and avoidable fixed costs. We simulate this latter condition by retiring enough of these uneconomical units to bring the reserve margin down to its pre-competition level.

In calculating customer response to RTP, we had to make assumptions on how regulators in both regions would treat TCs. At one extreme, the state regulators in both regions could completely deregulate retail prices and allow customers to face market prices. In the Northwest, retail prices and producer profits would increase; in California, retail prices and producer profits would drop. At the other extreme, the state regulators could allow 100% recovery of all TCs, in which case post-competition prices would be very close to pre-competition regulated prices.

We assumed for the current simulation that state regulators in the Northwest would impose a cap on retail prices to ensure that they do not increase above regulated prices. The Montana legislature (1997) passed a law to cap electricity prices from July 1998 through June 2000 at their July 1, 1998, levels. The California legislature (1996) and PUC imposed a 10% price cut, which translates into a roughly 15% cut in the price of generation. We assumed that TCs would be refunded to customers in the Northwest and collected from customers in California through the energy charge (i.e., in ¢/kWh).

As shown in Table 2, the combination of RTP and a price cap leads to essentially no change in total electricity consumption in the Pacific Northwest. On the other hand, RTP combined with a 15% cut in the price of generation leads to a 4.6% increase in both consumption and load factor in California. The California load-shape changes free up transmission capacity so that electricity flows from the Northwest to California increase by 4% from the base case.#

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*These analyses assume an overall price elasticity of demand of -0.5 and a time-of-use elasticity of -0.1. The very low value used for customer response to RTP is based on the notion that, by the year 2000, many customers will be unwilling or technically unable to respond to such prices. We ignore the costs and time to install time-of-use metering.

#When no TCs are allowed to be recovered in California or collected in the Northwest (i.e., retail customers face market prices), bulk-power flows increase from 17,300 to 39,200 GWh. EIA's projected increase in trade between the two regions (from 22,000 to 43,000 GWh) is similar (Church 1997).

Table 2. Pre- and post-competition electricity use, with post-competition customer response to real-time pricing[a]

	Pacific Northwest	California	Total[b]
Electricity use (GWh)			
Pre-competition	242,800	250,100	493,000
Post-competition	242,800	261,500	504,300
Load factor (%)			
Pre-competition	69.4	59.0	68.9
Post-competition	68.6	61.7	71.5

[a]See Appendix Table C-2 for additional details on this case.

[b]The totals are the electricity-consumption-weighted sums of the values for the two regions. The post-competition load factor is higher than the load factor in either region because the Northwest is winter peaking and California is summer peaking.

Because peak demands in the two regions are virtually unchanged between the base case and the post-competition case, no uneconomical generating units are retired (the second factor discussed at the beginning of this section).

Market prices in both the Northwest and California increase slightly (by 6%, as shown in Table 3) in spite of the 4% increase in electricity sales from the Northwest to California. These price increases occur because demand is higher in California, leading to the use of more-expensive generating units.

Table 3. Pre- and post-competition electricity prices (¢/kWh and percentage change from base case)

	Pacific Northwest	California
Market price	3.02 to 3.19 (+6%)	3.11 to 3.31 (+6%)
Market price + transition costs[a]	1.91 to 1.89 (-1%)	3.96 to 3.37 (-15%)
Regulated price	1.91 to 1.90 (0%)	3.96 to 3.92 (-1%)

[a]For this case, retail electricity prices in the Northwest are capped at the pre-competition regulated price; prices in California are capped at 85% of the pre-competition level.

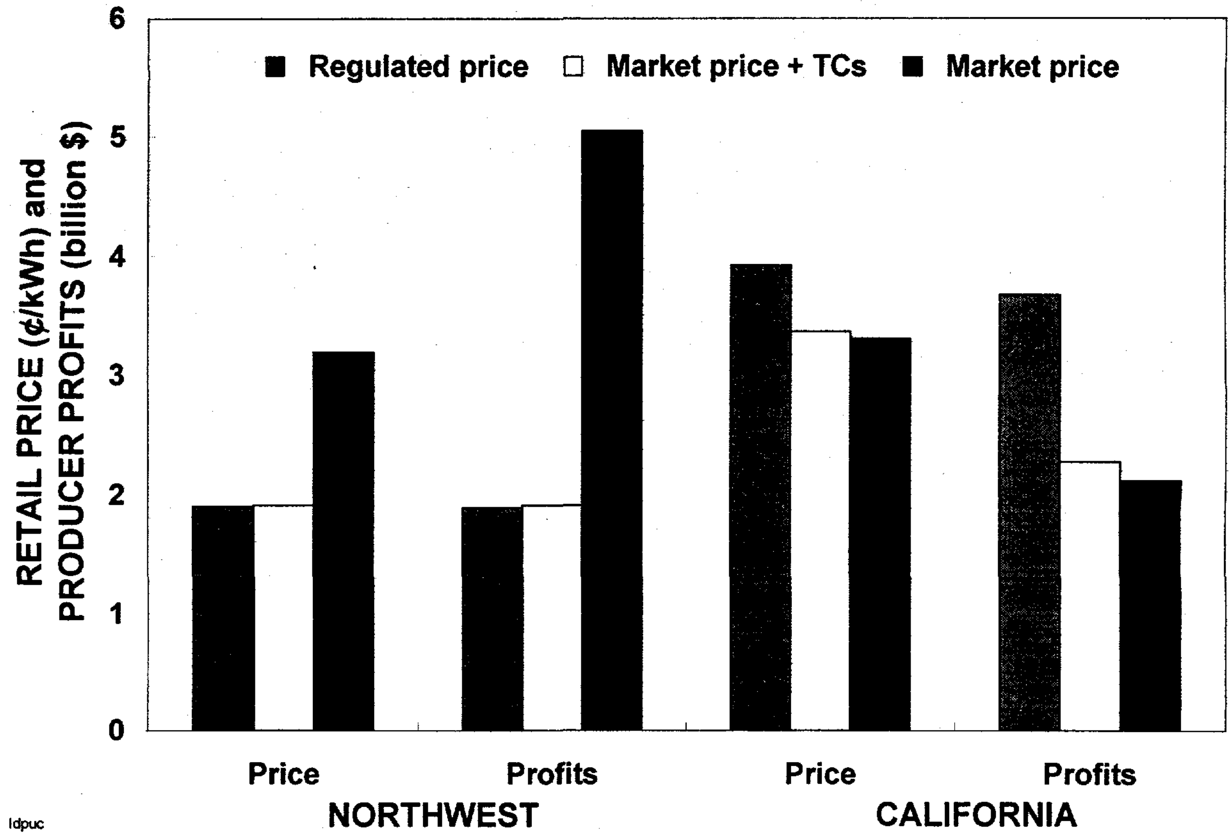

Fig. 4. **The effects on producer profits of changes in retail electricity prices for the post-competition case in which customers face real-time pricing.**

As the retail price of electricity changes from market price to market price plus TCs to regulated price (Table 3), producer profits also change (Fig. 4). (Profits are defined here as revenue minus avoidable costs.) If prices in the Northwest are allowed to increase from their regulated values to market levels, producer profits will increase dramatically from the authorized recovery of unavoidable fixed costs of $1.89 billion to $5.05 billion. Most of this $3.16 billion increment can be assigned to shareholders; none of it is needed for depreciation or interest payments on bonds, but some is needed for taxes. In California, a shift from regulated to market prices would reduce utility recovery of unavoidable fixed costs from $3.68 billion to $2.12 billion.

HIGHER NATURAL-GAS PRICES

Beginning with the base case discussed above, we ran a case in which natural-gas prices are 20% higher in both regions. The amount of electricity trading between the two regions is virtually unchanged because of this increase in gas prices. On the other hand, the variable cost of electricity production across both regions increases by 11%, from 1.30 to 1.45¢/kWh (Table 4 and Fig. 5). The market price of electricity increases by 17%, from 3.07 to 3.60¢/kWh. Marginal prices increase much more than average prices because gas-fired generation is on the margin for a large fraction of the year. Correspondingly, the low-cost hydro, which accounts for almost one-third of total electricity production in the two regions, is always inframarginal.

TCs decline in both regions (i.e., the positive TCs in California are smaller, and the negative TCs in the Northwest are higher). The higher price of natural gas makes the generators in California more economical and increases the economic value of the hydroelectric resources in the Northwest. Because of these changes in TCs, the effects of higher gas prices on the sum of market price plus TCs and on regulated prices are much less than the effects on market prices alone. This, of course, is how competitive markets are intended to operate. Competitive prices (reflected here in annual averages of hourly spot prices) are expected to track closely the underlying marginal costs of electricity production. Regulated prices, on the other hand, track average costs.

Table 4. The effects of a 20% increase in natural-gas price on the costs and prices of bulk-power electricity (¢/kWh and percentage change from base case)[a]

	Pacific Northwest	California
Market price	3.02 to 3.56 (+18%)	3.11 to 3.64 (+17%)
Market price + transition costs	1.91 to 1.94 (+2%)	3.78 to 4.07 (8%)
Regulated price	1.91 to 1.95 (+2%)	3.96 to 4.23 (+7%)
Variable cost	0.75 to 0.81 (+9%)	1.92 to 2.16 (+13%)

[a]See Appendix Table C-3 for additional details on this case.

LOWER HYDROELECTRIC OUTPUT

Beginning with the base case discussed above, we ran a case in which the amount of hydroelectric energy produced in the Northwest is cut by 20%. Unlike the case with higher gas prices, lower hydroelectric output dramatically affects trade between the two regions. Sales from the Northwest to California are cut by 87%, from 17,300 to only 2,300 GWh. Sales from California to the Northwest jump from 200 GWh to 11,100 GWh.

Overall, the market price increases by 48%, from 3.07 to 4.54¢/kWh. Because the amount of hydroelectric generation is lower than in the base case, the remaining generating units operate at higher capacity factors. Because the generators operate for more hours, they generate additional revenues, and therefore TCs are lower than in the base case. Even in the Northwest, where one might expect that the loss of 20% of the region's low-cost generation output would increase TCs, this is not the case. The TCs decrease from -1.1 to -2.4¢/kWh in the Northwest and from 0.7 to -0.6¢/kWh in California. Because of these changes in TCs, the sum of market price plus TCs changes much less than does market price; the same is true for regulated price (Table 5 and Fig. 5).

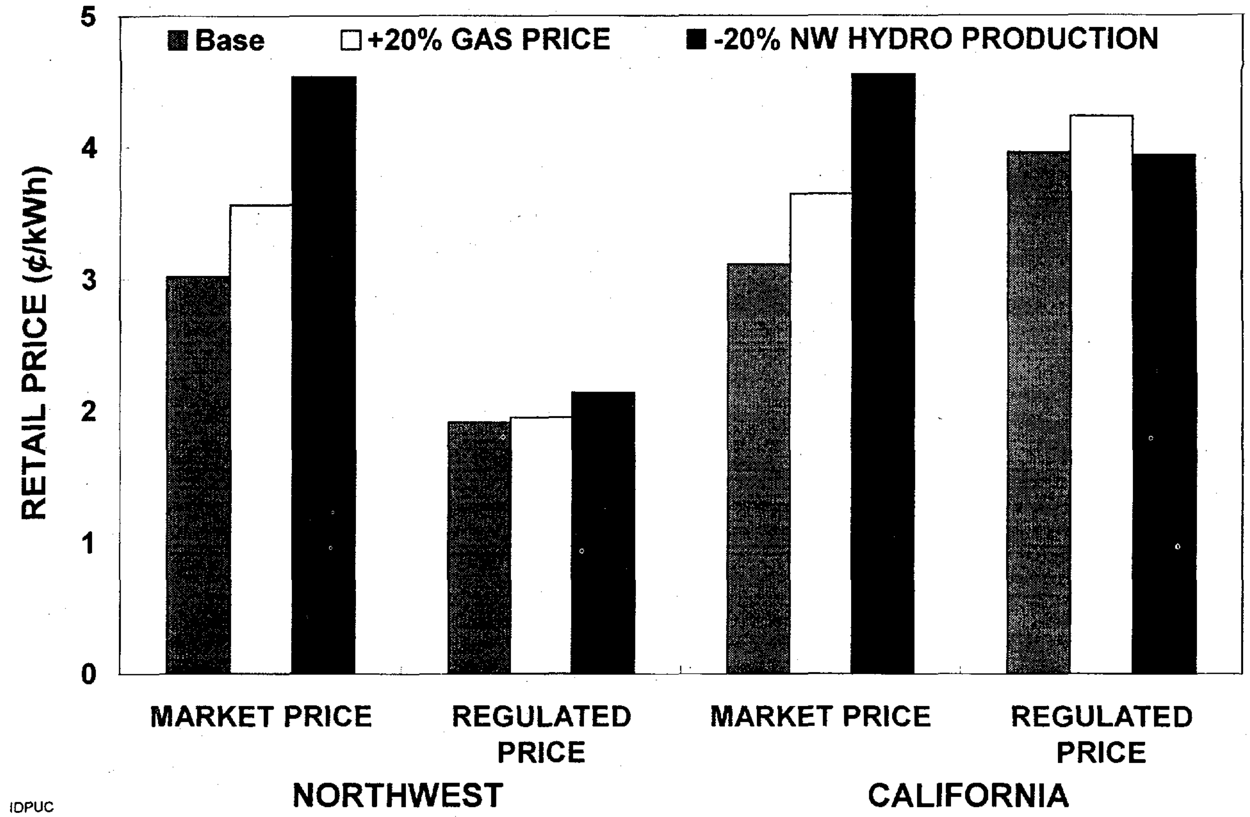

Fig. 5. **Market and regulated prices for the two sensitivity cases analyzed here.**

Table 5. **The effects of a 20% cut in the Northwest's hydroelectric output on the costs and prices of bulk-power electricity (¢/kWh and percentage change from base case)[a]**

	Pacific Northwest	California
Market price	3.02 to 4.53 (+50%)	3.11 to 4.55 (+46%)
Market price + transition costs	1.91 to 2.27 (+19%)	3.78 to 3.92 (+4%)
Regulated price	1.91 to 2.27 (+19%)	3.96 to 3.94 (-1%)
Variable cost	0.75 to 0.84 (+12%)	1.92 to 2.02 (+5%)

[a]See Appendix Table C-4 for additional details on this case.

CONCLUSIONS

This study examined retail electricity prices in the Pacific Northwest and California as they might develop for the year 2000. We analyzed different sets of assumptions concerning electricity production and bulk-power trading between these two regions. We used a simple two-region planning model, ORCED, to conduct these analyses. The purpose of these analyses was to see how retail customers in the Northwest (a region with an abundance of low-cost hydroelectricity) would fare under different conditions.

Our initial plan was to focus on the effects of bulk-power trading between the Northwest and California on retail prices and producer profits. The study, however, turned out to deal more with transition costs and marginal- vs average-cost pricing than with trading. This shift occurred for three reasons.

- The EIA (1997) analysis of electricity competition and our conversations with analysts in both regions suggest that the transmission links are already fully used to transfer power between the two regions. In other words, expansion of wholesale competition (e.g., full implementation of Orders 888 and 889 issued by the Federal Energy Regulatory Commission and creation of independent system operators in the West) might have little effect on the magnitude of bulk-power flows between the two regions. (Over time, new transmission facilities might be constructed, which would permit additional trading.)

- Initiation of retail competition, however, could affect both bulk-power trading and retail prices. Both the ORCED and EIA analyses suggest that bulk-power transactions between the two regions will increase in response to RTP. Customers shift their electricity use from high- to low-price periods; such temporal changes unload transmission lines and, thereby, free up additional capacity.

- Even with retail competition, the prices that retail customers face, at least for the first few years after competition begins, will depend on PUC decisions as well as on market forces. That is, PUCs may be able to create a transition period during which producers and consumers share the gains of competition through transition charges (positive in California and negative in the Northwest).

The ORCED analyses deal only with a single year (2000); treat generation only (and exclude transmission, distribution, and customer-service costs); ignore potential costs of making the transition to competitive electricity markets (e.g., to create independent system operators and to support retraining and early retirement activities for utility personnel); and ignore the potential effects of competition on generator productivity (e.g., lower forced and planned outage rates) and on production costs (e.g., lower heat rates and O&M costs).

The analysis conducted here leads to these conclusion:

- Even when substantial differences exist in the production costs between two regions, the amount of electricity traded between them may be modest.[*] The limited amount of trading is a consequence of the fact that much of the low-cost generation in the Pacific Northwest is operated at maximum capacity to meet native load in that region. More broadly, the amount of generating capacity in either region available for inter-regional transactions is limited by the loads in both regions.

- Absent regulatory intervention, retail competition would increase profits for producers in the Northwest and lower prices for consumers in California at the expense of consumers in the Northwest and producers in California. This finding is consistent with EIA's (1997) results, which showed that competitive prices in two low-cost regions, the Northwest Power Pool and the Mid-Continent Area Power Pool, are likely to be higher than regulated prices.

- However, state regulators may be able to capture some or all of the increased profits and use them to lower electricity prices in the low-cost region. Perhaps the most straightforward way to allocate the costs and benefits to retail customers is through development of TC charges or credits. Given this option, the consumers in both regions can benefit from competition.[#]

- The magnitude and even direction of bulk-power trading between regions depends strongly on the amount of hydroelectric power and energy available in the Northwest. Market prices respond much more strongly to changes in natural-gas prices and hydro output than do regulated prices. Indeed, market prices are intended to closely track changes in marginal costs, while regulated prices typically track changes in average cost.

Because this study analyzed a year-2000 snapshot, we are unable to discuss quantitatively the dynamics of competitive markets. This limitation is especially important for

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[*]The EIA (1996) *Annual Energy Outlook 1997* projects that, on average, exports from the 13 regions it analyzed amount to 6% of electricity consumption for the year 2000. California, with net imports equal to almost 23% of retail electricity use, is the major exception.

[#]Because municipal and cooperative utilities account for much of the electricity sold at retail in the Pacific Northwest, state legislatures, city councils, and coop boards, as well as PUCs, will decide whether and how to impose TC credits.

the post-TC period in the Pacific Northwest. When the transition period is over and customers no longer receive the negative TC credit, will their prices increase beyond what would otherwise occur? We speculate that, in the long term, competitive forces will reduce the costs of producing power. And the regulated price of electricity might rise because of likely environmental restrictions on the use of the region's existing hydro resources and because growing electricity demands can be met only by constructing new nonhydro facilities (which will have production costs much greater than those of the existing hydro facilities).

The assignment of negative TC credits to retail customers in low-cost states is only one of several ways that PUCs can protect retail customers. Washington Water Power (1997), for example, proposed a "portfolio access model" that would offer choices to retail customers and protect small customers from price increases. The menu of choices includes service under current regulated rates, commodity pricing that tracks annual market prices, and commodity pricing that tracks monthly market prices.

The bottom line from this analysis is that increased competition *can* benefit retail customers in high-cost regions without harming customers in low-cost regions. Such a desirable outcome, however, is not automatic. State regulators may have to intervene to be sure that what would otherwise be additional profits for the producers in the low-cost region are used to lower prices to retail customers. This conclusion is consistent with a finding from the Northwest Power Planning Council (1997) that "higher average costs in California need not mean higher bills for the Northwest." The Council offers two reasons for its conclusion, also consistent with the present analysis, related to competition in bulk-power markets and treatment of TCs.

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We thank Keith Hessing, Stephanie Miller, and Marsha Smith for their guidance and support throughout this project. We thank Laura Church, Wally Gibson, and Patrick McAuliffe for sending us data for the two regions studied here. We thank Gale Boyd, Richard Byers, Laura Church, Richard Collins, Kenneth Costello, Bruce Folsom, Ric Gale, Keith Hessing, Michael Lee, Stephanie Miller, Patrick McAuliffe, Terry Morlan, and Julie Simon for their very helpful comments on a draft of this report. We thank Fred O'Hara for editing the report and Ethel Schorn for managing its approval and production processes.

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OAK RIDGE COMPETITIVE ELECTRICITY DISPATCH MODEL

This appendix briefly describes the bulk-power market simulation model, ORCED, which we developed at Oak Ridge National Laboratory for the analysis of various issues related to the restructuring of the U.S. electricity industry. Support for model development was provided primarily by the U.S. Environmental Protection Agency.

ORCED DESCRIPTION

ORCED is an expanded version of part of ORFIN (Oak Ridge Financial Model).* Whereas ORFIN is a comprehensive electric-utility planning model, ORCED deals only with generation. We developed ORCED to aid in the analysis of the operation of competitive (as opposed to the traditional regulated) bulk-power markets. We are using the model to examine issues related to:

- CO_2 emissions from the U.S. electricity sector;
- The effects of competition on retail customers in low-cost regions;
- The ability of different transition-cost recovery and trueup mechanisms to meet particular public-policy objectives;
- Horizontal market power (the concentration of generation assets among a few owners);
- Generator profitability [which units will be shut down because their expected revenues will not cover the sum of their fuel costs, variable O&M costs, and (avoidable) fixed O&M costs]; and
- Optimal mix of new and existing generators, including the effects of new generating and end-use energy-efficiency technologies.

The model can simulate different bulk-power market structures. In particular, the user can specify one of three pricing schemes:

*S. W. Hadley 1996, *ORFIN: An Electric Utility Financial and Production Simulator*, ORNL/CON-430, Oak Ridge National Laboratory, Oak Ridge, TN, March.

- An energy-only spot price in ¢/kWh (as proposed for the California independent system operator). When unconstrained demand exceeds available supply, what would otherwise be unserved energy is "curtailed" because spot prices rise sufficiently to suppress demand to match the level of available generating capacity. The user simulates this situation by specifying a value for the price elasticity during these time periods. ORCED uses the amount of demand to be curtailed and the price elasticity to calculate the value of unserved energy in ¢/kWh.

- An energy-only spot price plus the loss-of-load probability (capacity) component used in the United Kingdom. Here, the user specifies a value for unserved energy (e.g., 200¢/kWh), which the model multiplies by the loss-of-load probability. The resultant product is then added to the energy-only spot price during hours with unserved energy.

- An energy-only spot price plus a capacity-reservation price (in $/kW-year), as proposed by the PJM Interconnection.

In addition to these pricing schemes, we are using ORCED to examine the issues listed above as functions of the following factors:

- Characteristics of individual generators: type of unit, differences in capital and other fixed costs ($/kW-year) vs fuel and variable O&M costs (¢/kWh), dispatchability (e.g., fully dispatchable coal plant vs must-run nuclear unit vs stochastic wind plant), and forced- and planned-outage rates (%);

- Customer and load characteristics: shape of the load curve, price elasticity of demand, and value of unserved energy;

- Generating-resource portfolio: mix of generating units and the relationship between generating capacity available and unconstrained peak demand; and

- Capacity, cost, and losses in the transmission link between the two regions.

ORCED is a two-region production-costing model that uses load-duration curves rather than chronological loads as inputs (Figs. 6 and 7).* The model is run twice for the year of simulation: once for an onpeak season and a second time for an offpeak season. These calculations are done separately for each region. The model then permits trading to occur between the two regions. The shape of the load-duration curves can differ between the two regions to allow for the possibility that the two systems experience their peak demands at different times.

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*A load-duration curve is created by ordering hourly system demands (in MW) from highest to lowest. The resultant curve shows the fraction of time (for the specified time period) that demand exceeds a particular value, ranging from the one-hour system peak down to the minimum demand.

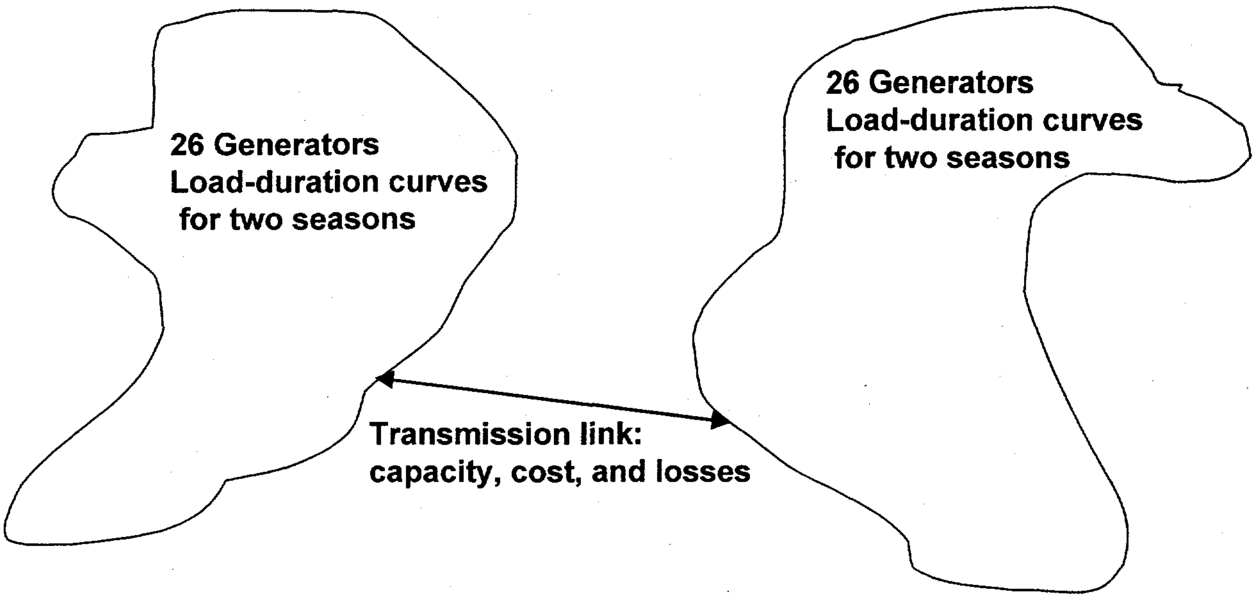

Fig. 6. ORCED analyzes bulk-power markets for two regions connected by a single transmission link.

Use of load-duration curves is computationally much simpler and faster than the hour-by-hour analysis of chronological-dispatch models. This simplification, however, has a price: because it obscures the timing of system loads, production-cost analysis on the basis of load-duration curves cannot analyze the details of generator operations and costs, especially those associated with minimum and maximum loading points, incremental heat rates, startup times and costs, and minimum shutdown times. To partially remedy these problems, ORCED analyzes two user-specified seasons each year and adds a startup cost (in \$/kW) for units that operate less than 10% of the hours in each season.

For each season, the model has available to it 26 generating units. The first 25 units are characterized in terms of capacity, forced- and planned-outage rates, fuel type, heat rate, variable O&M costs, fixed O&M costs, and annual capital costs (based on initial construction cost, year of completion, and capitalization structure). The last unit is an energy-limited hydro unit, for which the inputs include, in addition to those noted above, the plant's onpeak and offpeak capacity factors (equivalent to its maximum energy output for each season). This treatment of hydro as energy-limited ensures that hydro displaces the most expensive energy (i.e., at the top of the load-duration curves).

The model dispatches these 26 generating units separately for the two seasons. Although the calculation process is the same for the two seasons, the results differ because of differences in the load-duration curves and because all the planned maintenance is assumed to occur in the offpeak season (Fig. 7).

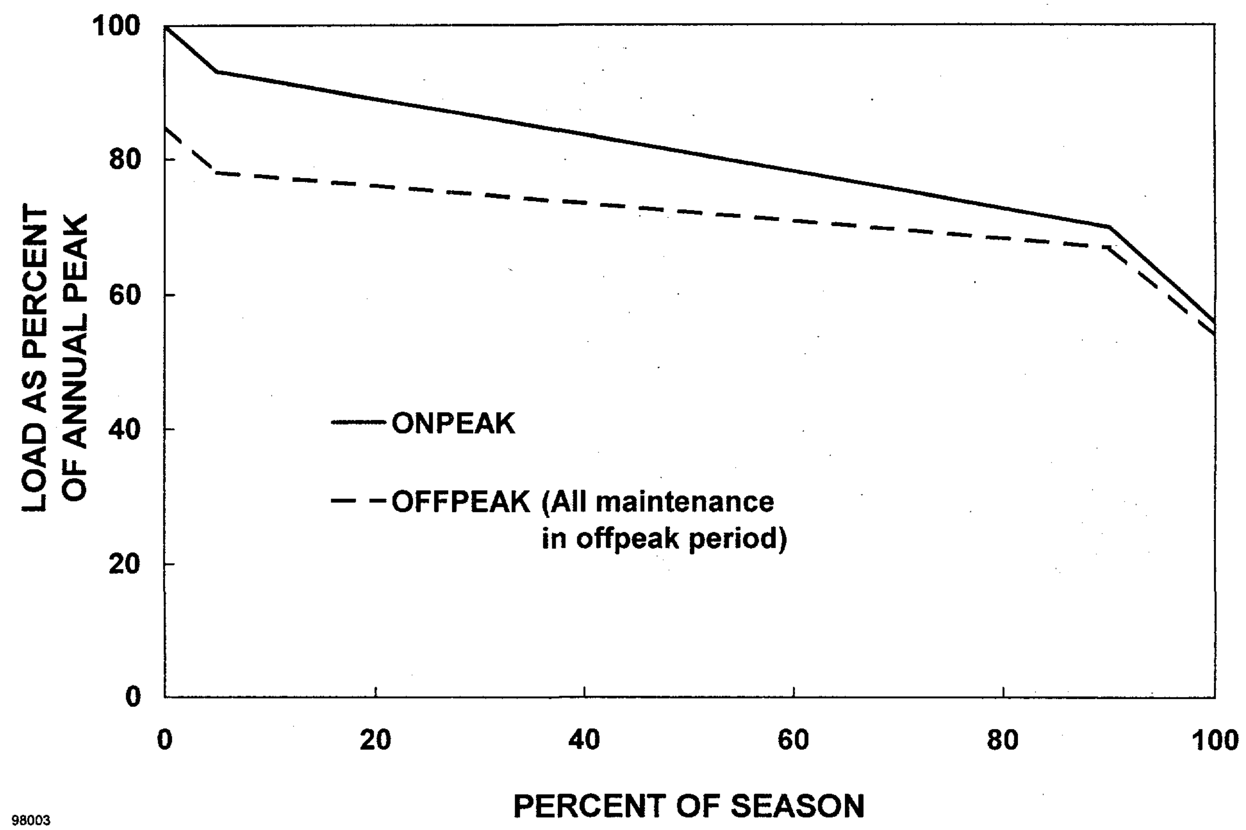

Fig. 7. ORCED analyzes customer loads on the basis of load-duration cuves for two user-specified seasons.

The plants are first dispatched against the load-duration curve on the basis of bid price, the default for which is variable (fuel plus variable O&M) costs. (If the plant owner bids a zero price for a unit, the generator is treated as a must-run unit and is dispatched first by the model.) Because plants are not available 100% of the time, we also model forced outages on a probabilistic basis.* Thus, the higher-cost plants will see not only customer loads but also "equivalent demands" based on the probability that plants lower (i.e., less expensive) in the dispatch order will be undergoing a forced outage. The model creates an equivalent load-duration curve for each plant, which extends the amount of time the plant runs based on the forced-outage rates of the plants lower in the dispatch order.

ORCED calculates market prices (based on the bids from individual generators) for each time period during the two seasons and then permits trades between the two regions. Trading between the two regions is a function of the bid prices of the marginal units in both regions as well as the costs and losses of the transmission link between the two regions. The market-

*The amount of computer time required for a full simulation depends strongly on the number of generators treated probabilistically. We found a reasonable tradeoff between computing time and accuracy when about 10 plants are modeled probabilistically and the other 16 are derated.

clearing price at any given time is based on the bid price of the marginal generator (the last one called upon in the dispatch order) after all cost-reducing trades are completed. The prices also incorporate any externally imposed uplift charge, capacity charge, and emission taxes. The prices during high-demand hours also reflect generator startup costs and the costs of any unserved energy for those hours during which unconstrained demand exceeds supply.

ORCED can be run iteratively to estimate customer response to changes in overall electricity-price levels and to real-time pricing. User inputs include an overall price elasticity of demand and a time-of-use elasticity. The former elasticity is used to adjust the entire load-duration curve up (or down) in response to decreases (or increases) in the overall price of electricity. The latter elasticity is used to adjust each point on the load-duration curve up (or down) based on decreases (or increases) in the price of electricity during that time period.

ORCED can use the time-of-use elasticity to calculate the value of unserved energy (in ¢/kWh) that equilibrates supply and demand when unconstrained demand would otherwise exceed the amount of generating capacity then online. Alternatively, the user can specify a value for unserved energy. A third option entails user specification of a minimum reserve margin and the associated annual capacity payment (in $/kW-year) to pay for this "extra" capacity.

ORCED can be run in either a simulation mode or an optimization mode. In the simulation mode, the model runs as a production-costing model to determine the costs of meeting customer electricity demands given a fixed set of generating units in the two regions. In the optimization mode, ORCED runs as a combined capacity-optimization and production-costing model to determine the "optimal" mix of generating units available that year as well as the least-cost use of those generators to meet customer demands. The user can specify different objective functions in the optimization routine, including minimization of the total cost of producing electricity, minimization of the sum of variable plus avoidable fixed costs, minimization of electricity price, or maximization of producer profits.

The user can also impose constraints on the optimization. These constraints can apply to individual generating units or to the system as a whole. For example, maximum-capacity constraints could be imposed on existing generating units (i.e., those units constructed before the year of the simulation). System constraints could specify a minimum reserve margin or a carbon-emission cap, as examples.

INPUTS

The input sheets for the two regions are identical in content. The first set of inputs specify the level and shape of system load during the two user-specified seasons (i.e., the two load-duration curves), the number of generators that will be treated probabilistically (vs derated), the cost and CO_2 emissions per million Btu for each fuel type, and the financial characteristics of the generator owners (book and depreciation lifetimes, capitalization ratios, income and property tax rates, and return on bonds and common equity).*

This portion of the input sheet also allows the user to specify either the cost of unserved energy or a price elasticity of demand. In the former case, whenever demand exceeds supply, customers pay and suppliers receive that specified price for all the energy sold during that time period. If the elasticity option is used, the price of electricity increases beyond the cost of the most expensive unit then online until demand and supply equilibrate; the lower the elasticity value, the larger the price increase required to reduce demand to the level of available supply.

The user can also specify an uplift charge, which is added to every kWh sold, a tax on CO_2, or an annual capacity payment in $/kW-year. These various unserved-energy, price-elasticity, uplift-charge, and capacity-payment options allow one to test different structures for a competitive bulk-power market.

The model includes a user input on fuel plus O&M startup costs. This factor is used to ensure that generating units that operate only a few hours a year (i.e., that have capacity factors below 10%) recover all their variable costs, including those associated with startup, shutdown, and no-load operations.

The next set of inputs specify details for each of the 26 generators that are used by ORCED to meet system load (as specified by the two load-duration curves); see Fig. 8. For each of the first 25 generators, the user specifies unit capacity (MW), whether the plant is available for use during this particular analysis, outage rates (% per year), avoidable fixed (O&M) costs ($/kW-year), initial plant cost ($/kW) and year of completion (which are used by the fixed-charges-rate routine to compute the annual unavoidable fixed cost in $/kW-year), heat rate (Btu/kWh) and fuel type (to determine the unit's fuel cost in ¢/kWh), variable O&M cost (¢/kWh), and bid price (the default for which is the unit's fuel plus variable O&M cost). The user also provides unit-specific input assumptions for an energy-limited hydro unit, the 26th unit.

OUTPUTS

The ORCED output sheet summarizes the results of the particular analysis. Key results include the prices and costs in each region and for the two regions combined. These factors include the market price of power (the consumption-weighted annual average of hourly spot prices in ¢/kWh); the full-cost price (roughly equivalent to the regulated price of electricity); and the producer variable, avoidable fixed, and unavoidable fixed costs. These outputs also include consumer and producer costs in million dollars per year. These cost and price figures

*The user can specify different forms of generation ownership, such as traditional investor-owned utility, independent power producer, and renewable developer (to recognize particular tax benefits of renewables ownership).

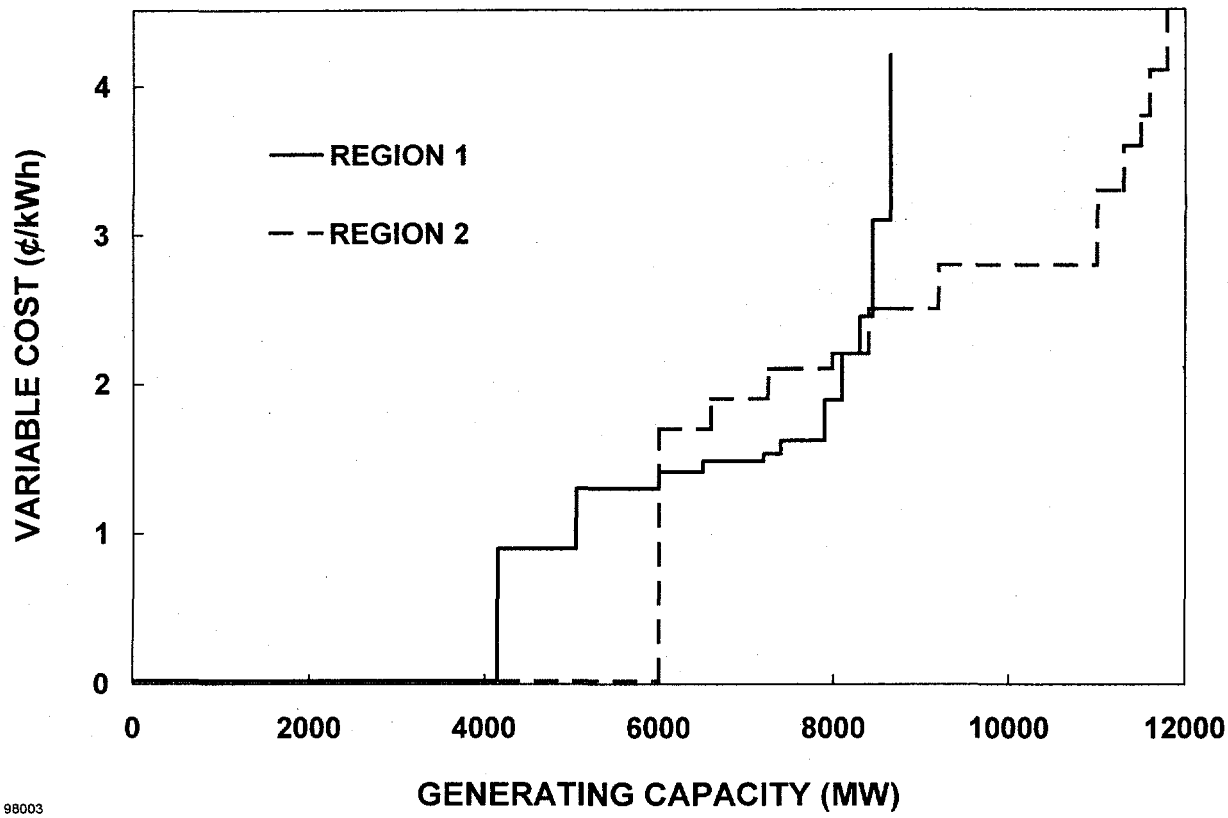

Fig. 8. User inputs specify generating-unit characteristics for 26 units in each region. ORCED then dispatches these units on the basis of either bid price or variable cost.

are all at the generator busbar (i.e., before accounting for intraregion transmission and distribution losses); however, the costs and prices do reflect inter-regional transmission costs and losses.

The summary information shows system reliability as measured by reserve margin and the loss-of-load probability and amounts of unserved energy in the two seasons. The amount of unserved energy, in combination with the assumed onpeak price elasticity, determines the cost of unserved energy. The model calculates the number of plants that are unprofitable relative to avoidable fixed costs and relative to total fixed costs. These "profitability" numbers are important in calculating actual and allowed transition costs and also in determining which generating units might be shut down in competitive electricity markets. The summary also shows total CO_2 emissions for this analysis year.

The detailed portion of the ORCED output shows operating results, revenues, and costs for each of the 26 generators in each region. These results show each unit's output, capacity factor, sales to the other region, and time on the margin for the year of analysis. These operating results are then used to determine annual revenues, variable costs, fixed costs, and net revenues as well as CO_2 emissions.

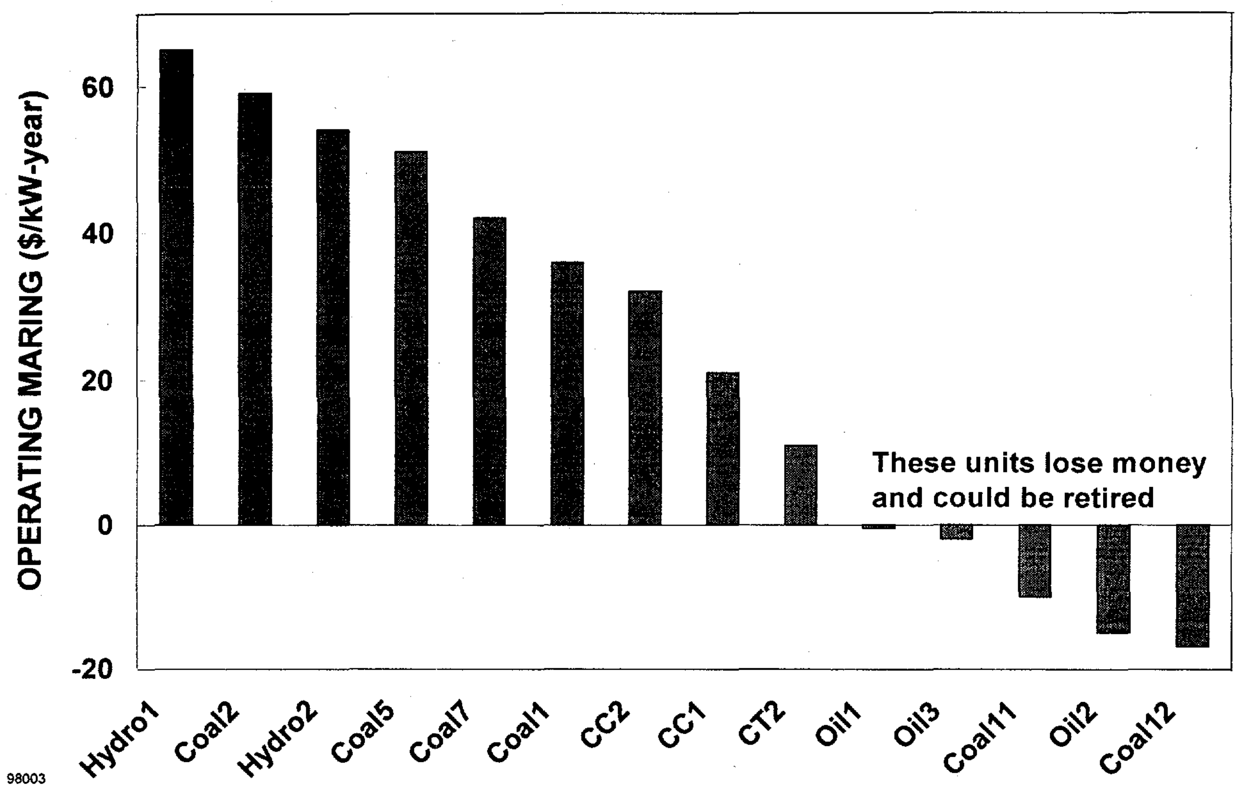

Fig. 9. **ORCED results showing the contribution to margin for a sample of the 26 generating units in one of the two regions.**

The ORCED output sheet also shows the earnings for each generator relative to variable and avoidable fixed costs (but not unavoidable fixed costs, which are primarily related to capital costs). Negative numbers reflect losses (in $/kW-year) and suggest that these units should be retired (Fig. 9).

Based on the least-bid-price dispatch, the model calculates the marginal cost of electricity for each hour of the simulation period. These costs are the hourly spot prices faced by customers. As discussed above, when there is insufficient generation to meet unconstrained demand, spot prices rise until demand is reduced to the level at which it equals the amount of supply online. This price is then used to calculate the value of unserved energy and is the price paid to all generators online during this brief period.

SUMMARY

ORCED includes the key features required for analysis of competitive bulk-power markets. Although it lacks the details of the large, sophisticated models (such as GE-MAPS), it offers important strengths. In particular, the model is easy to use and it can be run very quickly. Thus, analysts can test many different situations in a limited time. Finally, the model's simplicity enhances the ability to glean insights from model runs.

DATA SOURCES AND ORCED APPROXIMATIONS

PRODUCTION ASSUMPTIONS

The PowerDat database from Resource Data International (RDI) was consulted to find the utility-owned power plants in the two regions for the period 1993 to 1995. Data retrieved included capacity, generation, owner, fuel cost, operating cost (fixed and variable), maintenance cost, heat rate, year of construction, and capital cost. To minimize distortions associated with use of data for a single year, the variables were averaged over the three-year period.

In addition, the DOE/EIA Inventory of Generating Plants (EIA-861) was consulted to determine plants scheduled to be built in the two regions between 1995 and 2000. Representative variables were determined on the basis of technology-specific values used in the EIA *Annual Energy Outlook*.

Northwest Power Pool (NWPP)

The PowerDat database and the NWPP website were consulted to determine the members of the NWPP. Some 270 plants owned by these utilities were segregated into the 26 slots within ORCED's Region 1 on the basis of technology, fuel, O&M costs, capacity factor, year of construction, and heat rate. A small amount of capacity was not included because of inadequate data. Capital and operating costs for much of the hydro owned by the federal government (U.S. Army Corps of Engineers and Bureau of Reclamation) were missing. Representative values for these units were calculated on the basis of other hydro plants of similar age.

We allocated all 34,000 MW of the hydro power to the energy-limited category, allowing ORCED to use that capacity to lower peak demands preferentially rather than across the whole period on a probabilistic basis. For increased accuracy, we determined the fraction of hydro generation during the summer months versus the rest of the year from the EIA monthly generation report (EIA-759) for 1995.

Independent-power-producer (IPP) plant information was not included in the RDI database. According to the North American Electric Reliability Council (NERC) Electricity Supply and Demand database there will be 2168 MW of IPP capacity in the NWPP in 2000. We modeled this as gas-fired capacity.

California/Southern Nevada (CA/NV)

The PowerDat database listed the utilities in the subregion. Some 285 plants owned by these utilities were segregated into the 26 slots within ORCED's Region 2 on the basis of their characteristics as listed above. A small amount of capacity was not included because of inadequate data. Capital and operating costs for much of the hydro owned by the Bureau of Reclamation was missing. Representative values were calculated on the basis of other plants of similar age.

We allocated all 9500 MW of the hydro power to the energy-limited category, as explained above.

IPP plant information was not included in the RDI database. According to the NERC Electricity Supply and Demand database 8225 MW of IPP capacity is projected to be online in this region in 2000. The California Energy Commission's *1992 Electricity Report* details the split of nonutility generation as fossil-fired plants totaling 5565 MW and renewable plants (a combination of wind, solar, and biomass) totaling 2646 MW. We represented the IPPs as four plants within ORCED with representative values for the variables above.

DEMAND ASSUMPTIONS

RDI provides hour-by-hour load data by utility for a given year. We plotted the 1995 data for the utilities in both regions and determined that a three-month period between June 3 and Sept 2 would best represent the peak season within ORCED. We then calculated load-duration curves that best fit the data for the peak- and off-peak seasons for each region (four curves in all). Peak demands were higher than those reported by EIA and NERC. We chose to use the NERC peak demands and the RDI load shapes.

The peaks in CA/NV did not occur at the same time as the peaks in the NWPP region. In ORCED, we simulated this situation by shifting the peak demands for one region to a lower-demand portion of the load-duration curve for the other. The correlation between demands in the two regions is quite high for the peak season. However, for the off-peak season, NWPP had its highest loads in December, while CA/NV had its peak in the September and May periods, creating some variance. We shifted the CA/NV load-duration curve to approximate the actual relationship between the peaks in the two regions.

TRADING ASSUMPTIONS

After ORCED dispatches plants to meet native load only, each season is divided into up to 120 time periods. Then, generators in each region compete against each other in each time period. A transmission constraint of 7000 MW, with zero energy loss and zero transmission fee, was used for all cases. The price that each producer receives is based on the plant on the margin.

SUMMARY OUTPUTS FROM ORCED

Appendix Table C-1. ORCED Results for Base Case

	Northwest	California	Combined		
Reserve Margin	30.4%	17.2%	33.3%		
pretrade LOLP, % of period	1.1944	1.4629		Transmission	
Load factor	69.4%	59.0%	68.9%	MW Capac.	7,000
Peak Demand, MW	39,954	48,432	88,386	Fee, ¢/kWh	-
Energy Demand, GWh	242,844	250,148	492,992	paymt, M$	-
Wholesale Sales, GWh	17,254	197	17,451	Losses, %	0%
Wholesale Purch, GWh	(197)	(17,254)	(17,451)	Lost GWh	(0)
Generation, GWh	259,822	233,085	492,907	Lost M$	-
Unserved Energy, GWh	79	6	85	Total M$	-
Capacity Factor	56.9%	46.9%	51.7%	Peak trans	4555.86

	Northwest	California	Both
~Market price, ¢/kWh	3.02	3.11	3.07
Full-cost-based Price	1.91	3.96	2.95
Producer price, ¢/kwh	3.03	3.13	3.08
Variable Cost	0.75	1.92	1.30
Avoidable Cost	1.26	2.45	1.82
Total Cost	1.98	4.03	2.95
Costs w/ Unserved, M$			
Variable+Start-up Cost	1,944	4,491	6,436
Avoidable Cost	3,267	5,746	9,013
Total Cost	5,157	9,430	14,587
Total Consumer Cost	7,343	7,803	15,146
Producer earnings re Avoi	4,600	1,572	6,173

RESULTS FOR NORTHWEST

Plant Name	Capacity MW	Generation MWyr	Wholesale Sales, MWyr	Capac Factor	Time on Margin, %	Revenue M$	Var. +Start Cost M$	Avoidable Fxd Cst M$	Unavoid. Fxd Cst M$	Net Revenue, M$ Avoidable	Total
Coal 1	430	348	-	80.9%	0.00	91	21	14	12	56	43
Coal 2	619	555	-	89.6%	0.00	146	38	15	14	92	78
Coal 3	798	646	-	80.9%	0.00	170	48	59	37	62	26
Coal 4	805	754	-	93.7%	0.00	198	55	18	28	125	97
Coal 5	992	888	-	89.5%	0.00	233	79	23	78	130	52
Coal 6	1,145	926	-	80.9%	0.00	243	81	33	145	130	(16)
Coal 7	243	210	-	86.5%	0.00	55	20	6	15	29	14
Coal 8	1,252	1,078	-	86.1%	0.00	283	109	25	61	149	88
Coal 9	626	506	0.00	80.9%	0.00	133	53	14	29	65	36
Coal 10	700	566	-	80.9%	0.00	149	65	18	16	67	51
Coal 11	689	557	73.64	80.9%	0.00	146	72	11	14	63	49.01
Coal 12	697	564	119.67	80.9%	0.00	148	77	11	11	59	47.84
Coal 13	393	318	51.18	80.9%	0.00	83	43	10	37	30	(6.71)
Coal 14	380	307	72.91	80.9%	0.00	81	46	8	32	26	(5.88)
Coal 15	532	427	263.09	80.2%	0.73	112	88	14	70	10	(59.69)
IPP-1	1,084	951	-	87.7%	0.00	249	173	11	64	65	0.80
IPP-2	1,084	1,001	-	92.3%	0.00	263	219	11	48	33	(15.48)
WNP 3	1,100	883	-	80.3%	0.00	232	64	90	329	78	(251.29)
Gas Steam	1,187	1,006	793.77	84.8%	2.25	266	218	18	16	30	14.23
Gas CC	1,186	1,072	282.27	90.4%	0.00	281	170	16	30	95	64.78
Gas GT 1	693	324	305.99	46.8%	13.02	93	80	7	15	7	(7.49)
Gas/Oil GT2	290	1	1.04	0.4%	0.00	2	1	5	0	(3)	(3.69)
Geotherm	23	18	0.00	80.0%	0.00	5	1	4	7	0	(6.48)
Steam Other	467	190	6.02	40.7%	0.00	50	25	14	44	12	(32)
IGCC	105	92	0.00	87.7%	0.00	24	8	5	25	11	(15)
Hydro Limited	34,591	15,472		45%	0.00	4,132	89	864	711	3,179	2,468
Total Generation	52,110	29,660	1,970		16.00	7,868	1,944	1,323	1,890	4,600	2,710

RESULTS FOR CALIFORNIA

Plant Name	Capacity MW	Generation MWyr	Wholesale Sales, MWyr	Capac Factor	Time on Margin, %	Revenue M$	Var. +Start Cost M$	Avoidable Fxd Cst M$	Unavoid. Fxd Cst M$	Net Revenue, M$ Avoidable	Total
Gas-St1	2,221	1,514	(0.00)	68.2%	0.54	398	305	32	25	61	36
Gas-St2	1,630	1,015	0.00	62.3%	0.82	268	217	29	33	22	(11)
Gas-St3	2,021	1,189	(0.00)	58.8%	4.23	317	272	30	23	14	(9)
Gas-St4	1,964	1,063	0.00	54.1%	10.35	286	251	16	17	19	3
Gas-St5	2,022	978	0.00	48.4%	9.59	267	231	28	34	8	(26)
Gas-St6	1,500	645	0.00	43.0%	5.30	179	155	13	19	11	(8)
Gas-St7	2,348	900	20.14	38.3%	11.16	254	218	26	18	10	(8)
Gas-St8	2,345	201	0.12	8.6%	8.56	80	52	25	20	3	(17)
Gas-St9	2,743	49	0.00	1.8%	2.41	37	20	45	32	(28)	(60)
Gas-St10	1,680	10	(0.00)	0.6%	0.72	14	6	30	19	(22)	(41)
Gas Turb	1,738	87	0.00	5.0%	6.21	45	27	7	47	11	(36)
Gas CC	2,235	1,675	(0.00)	75.0%	0.15	440	329	29	133	82	(52)
Gas/Oil Steam	2,300	498	2.28	21.6%	23.12	159	124	35	41	0	(40)
Gas/Oil Turb	649	7	0.00	1.2%	0.16	8	3	5	4	(1)	(5)
Coal 1	2,878	2,245	(0.00)	78.0%	0.00	589	257	76	72	256	184
Coal 2	991	724	0.00	73.0%	0.00	190	139	39	97	11	(86)
Diablo Canyon	2,160	1,734	0.00	80.3%	0.00	455	107	191	717	157	(559)
Palo Verde	1,046	840	0.00	80.3%	0.00	221	58	69	280	94	(187)
San Onofre	2,150	1,726	0.00	80.3%	0.00	453	129	202	571	123	(448)
Oil plants	827	4	(0.00)	0.5%	0.30	8	3	3	10	1	(8)
Geotherm	1,534	820	0.00	53.5%	0.00	215	76	122	122	18	(104)
IPP-1	2,034	1,017	-	50.0%	0.00	267	293	22	238	(48)	(286)
IPP-2	2,034	1,017	-	50.0%	0.00	267	316	22	285	(71)	(356)
IPP-3	1,497	749	0.00	50.0%	0.00	197	249	16	244	(69)	(313)
IPP-Renewable	2,646	1,720	-	65.0%	0.00	452	603	38	340	(188)	(528)
Hydro Limited	9,573	4,180		43.7%		1,226	25	103	242	1,097	855
Total Generation	56,768	26,608	23		83.62	7,291	4,464	1,254	3,684	1,572	(2,112)

Appendix Table C-2. ORCED Results for Post-Competition Case

	Northwest	California	Combined
Reserve Margin	28.9%	17.3%	33.6%
pretrade LOLP, % of period	0.9884	2.7759	
Load factor	68.6%	61.7%	71.5%
Peak Demand, MW	40,431	48,396	88,828
Energy Demand, GWh	242,804	261,524	504,328
Wholesale Sales, GWh	17,950	63	18,013
Wholesale Purch, GWh	(63)	(17,950)	(18,013)
Generation, GWh	260,741	243,533	504,274
Unserved Energy, GWh	(50)	104	54
Capacity Factor	57.1%	49.0%	52.9%

Transmission	
MW Capac.	7,000
Fee, ¢/kWh	-
paymt, M$	-
Losses, %	0%
Lost GWh	(0)
Lost M$	-
Total M$	-
Peak trans	4278.25

	Northwest	California	Both
~Market price, ¢/kWh	3.19	3.31	3.25
Full-cost-based Price	1.90	3.92	2.95
Producer price, ¢/kwh	3.20	3.34	3.27
Variable Cost	0.76	1.96	1.33
Avoidable Cost	1.26	2.47	1.85
Total Cost	1.99	3.98	2.95
Costs w/ Unserved, M$			
Variable+Start-up Cost	1,970	4,797	6,768
Avoidable Cost	3,293	6,052	9,345
Total Cost	5,183	9,736	14,919
Total Consumer Cost	7,752	8,698	16,449
Producer earnings re Avoi	5,049	2,121	7,171

RESULTS FOR NORTHWEST

Plant Name	Capacity MW	Generation MWyr	Wholesale Sales, MWyr	Capac Factor	Time on Margin, %	Revenue M$	Var. +Start Cost M$	Avoidable Fxd Cst M$	Unavoid. Fxd Cst M$	Net Revenue, M$ Avoidable	Total
Coal 1	430	348	-	80.9%	0.00	96	21	14	12	61	48
Coal 2	619	555	-	89.6%	0.00	154	38	15	14	100	86
Coal 3	798	646	-	80.9%	0.00	179	48	59	37	72	35
Coal 4	805	754	-	93.7%	0.00	209	55	18	28	136	108
Coal 5	992	888	-	89.5%	0.00	246	79	23	78	143	65
Coal 6	1,145	926	-	80.9%	0.00	256	81	33	145	143	(2)
Coal 7	243	210	-	86.5%	0.00	58	20	6	15	32	17
Coal 8	1,252	1,078	-	86.1%	0.00	298	109	25	61	164	104
Coal 9	626	506	0.00	80.9%	0.00	140	53	14	29	73	43
Coal 10	700	566	-	80.9%	0.00	157	65	18	16	75	59
Coal 11	689	557	40.59	80.9%	0.00	154	72	11	14	71	57.06
Coal 12	697	564	101.48	80.9%	0.00	156	77	11	11	67	55.98
Coal 13	393	318	42.74	80.9%	0.00	88	43	10	37	34	(2.12)
Coal 14	380	307	70.99	80.9%	0.00	85	46	8	32	31	(1.44)
Coal 15	532	429	269.00	80.7%	0.13	119	88	14	70	16	(53.49)
IPP-1	1,084	951	-	87.7%	0.00	263	173	11	64	79	14.51
IPP-2	1,084	1,001	-	92.3%	0.00	277	219	11	48	47	(1.06)
WNP 3	1,100	883	-	80.3%	0.00	245	64	90	329	91	(238.26)
Gas Steam	1,187	1,028	834.73	86.6%	0.78	285	223	18	16	45	29.07
Gas CC	1,186	1,072	310.74	90.4%	0.00	297	170	16	30	111	80.23
Gas GT 1	693	404	376.69	58.3%	4.01	121	99	7	15	15	0.50
Gas/Oil GT2	290	2	2.12	0.7%	0.00	5	2	5	0	(2)	(2.18)
Geotherm	23	18	0.00	80.0%	0.00	5	1	4	7	1	(6.22)
Steam Other	467	190	0.00	40.7%	0.00	53	25	14	44	15	(29)
IGCC	105	92	0.00	87.7%	0.00	26	8	5	25	12	(13)
Hydro Limited	34,591	15,472		45%	0.00	4,370	89	864	711	3,418	2,707
Total Generation	52,110	29,765	2,049		4.92	8,343	1,970	1,323	1,890	5,049	3,159

RESULTS FOR CALIFORNIA

Plant Name	Capacity MW	Generation MWyr	Wholesale Sales, MWyr	Capac Factor	Time on Margin, %	Revenue M$	Var. +Start Cost M$	Avoidable Fxd Cst M$	Unavoid. Fxd Cst M$	Net Revenue, M$ Avoidable	Total
Gas-St1	2,221	1,520	(0.00)	68.4%	0.19	422	307	32	25	83	58
Gas-St2	1,630	1,028	0.00	63.1%	0.43	286	219	29	33	37	4
Gas-St3	2,021	1,240	(0.00)	61.3%	2.51	346	283	30	23	33	10
Gas-St4	1,964	1,152	0.00	58.6%	4.98	324	271	16	17	37	20
Gas-St5	2,022	1,091	0.00	53.9%	8.95	311	257	28	34	26	(8)
Gas-St6	1,500	733	0.00	48.9%	5.94	213	176	13	19	24	5
Gas-St7	2,348	1,016	(0.00)	43.3%	10.75	301	246	26	18	29	12
Gas-St8	2,345	402	0.82	17.1%	20.97	149	101	25	20	23	3
Gas-St9	2,743	103	0.00	3.8%	5.90	73	37	45	32	(10)	(42)
Gas-St10	1,680	20	(0.00)	1.2%	1.04	28	11	30	19	(13)	(32)
Gas Turb	1,738	174	0.10	10.0%	9.36	84	48	7	47	30	(17)
Gas CC	2,235	1,676	(0.00)	75.0%	0.00	465	329	29	133	106	(27)
Gas/Oil Steam	2,300	852	6.22	37.1%	22.03	267	212	35	41	21	(20)
Gas/Oil Turb	649	14	0.00	2.1%	0.77	15	6	5	4	4	(0)
Coal 1	2,878	2,245	(0.00)	78.0%	0.00	623	257	76	72	289	217
Coal 2	991	724	0.00	73.0%	0.00	201	139	39	97	22	(75)
Diablo Canyon	2,160	1,734	0.00	80.3%	0.00	481	107	191	717	183	(534)
Palo Verde	1,046	840	0.00	80.3%	0.00	233	58	69	280	106	(174)
San Onofre	2,150	1,726	0.00	80.3%	0.00	479	129	202	571	148	(423)
Oil plants	827	8	(0.00)	0.9%	0.49	15	6	3	10	7	(3)
Geotherm	1,534	820	0.00	53.5%	0.00	227	76	122	122	30	(92)
IPP-1	2,034	1,017	-	50.0%	0.00	283	293	22	238	(32)	(271)
IPP-2	2,034	1,017	-	50.0%	0.00	283	316	22	285	(55)	(340)
IPP-3	1,497	749	0.00	50.0%	0.00	208	249	16	244	(57)	(302)
IPP-Renewable	2,646	1,720	-	65.0%	0.00	479	603	38	340	(161)	(501)
Hydro Limited	9,573	4,180		43.7%		1,340	25	103	242	1,212	969
Total Generation	56,768	27,801	7		94.30	8,137	4,761	1,254	3,684	2,121	(1,563)

Appendix Table C-3. ORCED Results for Natural-Gas Prices 20% Higher

	Northwest	California	Combined				Northwest	California	Both
						~Market price, ¢/kWh	3.56	3.64	3.60
Reserve Margin	30.4%	17.2%	33.3%			Full-cost-based Price	1.95	4.23	3.11
pretrade LOLP, % of period	1.1944	1.4629		Transmission		Producer price, ¢/kwh	3.56	3.66	3.61
Load factor	69.4%	59.0%	68.9%	MW Capac.	7,000	Variable Cost	0.81	2.16	1.45
Peak Demand, MW	39,954	48,432	88,386	Fee, ¢/kWh	-	Avoidable Cost	1.32	2.70	1.97
Energy Demand, GWh	242,844	250,148	492,992	paymt, M$	-	Total Cost	2.05	4.28	3.11
Wholesale Sales, GWh	17,287	197	17,485	Losses, %	0%	Costs w/ Unserved, M$			
Wholesale Purch, GWh	(197)	(17,287)	(17,485)	Lost GWh	(0)	Variable+Start-up Cost	2,113	5,069	7,182
Generation, GWh	259,856	233,051	492,907	Lost M$	-	Avoidable Cost	3,437	6,323	9,760
Unserved Energy, GWh	79	6	85	Total M$	-	Total Cost	5,326	10,007	15,334
Capacity Factor	56.9%	46.9%	51.7%	Peak trans	4555.86	Total Consumer Cost	8,637	9,139	17,776
						Producer earnings re Avoi	5,816	2,241	8,057

RESULTS FOR NORTHWEST

Plant Name	Capacity MW	Generation MWyr	Wholesale Sales, MWyr	Capac Factor	Time on Margin, %	Revenue M$	Var. +Start Cost M$	Avoidable Fxd Cst M$	Unavoid. Fxd Cst M$	Net Revenue, M$ Avoidable	Total
Coal 1	430	348	-	80.9%	0.00	107	21	14	12	72	59
Coal 2	619	555	-	89.6%	0.00	171	38	15	14	118	104
Coal 3	798	646	-	80.9%	0.00	200	48	59	37	92	56
Coal 4	805	754	-	93.7%	0.00	233	55	18	28	160	132
Coal 5	992	888	-	89.5%	0.00	274	79	23	78	172	93
Coal 6	1,145	926	-	80.9%	0.00	286	81	33	145	173	27
Coal 7	243	210	-	86.5%	0.00	65	20	6	15	39	24
Coal 8	1,252	1,078	-	86.1%	0.00	333	109	25	61	199	138
Coal 9	626	506	0.00	80.9%	0.00	156	53	14	29	89	60
Coal 10	700	566	-	80.9%	0.00	175	65	18	16	93	77
Coal 11	689	557	73.64	80.9%	0.00	172	72	11	14	89	74.93
Coal 12	697	564	119.67	80.9%	0.00	174	77	11	11	85	74.06
Coal 13	393	318	51.18	80.9%	0.00	98	43	10	37	45	8.06
Coal 14	380	307	72.91	80.9%	0.00	95	46	8	32	41	8.42
Coal 15	532	430	266.95	80.9%	0.00	133	89	14	70	30	(39.69)
IPP-1	1,084	951	-	87.7%	0.00	294	208	11	64	75	10.50
IPP-2	1,084	1,001	-	92.3%	0.00	309	262	11	48	36	(12.53)
WNP 3	1,100	883	-	80.3%	0.00	273	64	90	329	119	(210.26)
Gas Steam	1,187	1,006	793.77	84.8%	2.25	313	260	18	16	35	19.46
Gas CC	1,186	1,072	282.27	90.4%	0.00	331	203	16	30	112	81.85
Gas GT 1	693	324	305.99	46.8%	13.02	109	95	7	15	7	(7.58)
Gas/Oil GT2	290	1	1.04	0.4%	0.00	2	1	5	0	(3)	(3.69)
Geotherm	23	18	0.00	80.0%	0.00	6	1	4	7	1	(5.63)
Steam Other	467	190	6.02	40.7%	0.00	59	25	14	44	21	(23)
IGCC	105	92	0.00	87.7%	0.00	28	8	5	25	15	(10)
Hydro Limited	34,591	15,472		45%	0.00	4,856	89	864	711	3,903	3,192
Total Generation	52,110	29,664	1,973		15.26	9,253	2,113	1,323	1,890	5,816	3,926

RESULTS FOR CALIFORNIA

Plant Name	Capacity MW	Generation MWyr	Wholesale Sales, MWyr	Capac Factor	Time on Margin, %	Revenue M$	Var. +Start Cost M$	Avoidable Fxd Cst M$	Unavoid. Fxd Cst M$	Net Revenue, M$ Avoidable	Total
Gas-St1	2,221	1,511	(0.00)	68.0%	1.10	468	364	32	25	72	47
Gas-St2	1,630	1,015	0.00	62.3%	0.82	315	257	29	33	29	(4)
Gas-St3	2,021	1,189	(0.00)	58.8%	4.23	372	323	30	23	19	(4)
Gas-St4	1,964	949	0.00	48.3%	9.59	304	267	16	17	21	4
Gas-St5	2,022	1,093	0.00	54.0%	10.35	345	307	28	34	10	(24)
Gas-St6	1,500	645	0.00	43.0%	5.30	209	184	13	19	12	(7)
Gas-St7	2,348	900	20.14	38.3%	11.16	296	260	26	18	11	(6)
Gas-St8	2,345	201	0.12	8.6%	8.56	90	62	25	20	3	(17)
Gas-St9	2,743	49	0.00	1.8%	2.41	40	22	45	32	(28)	(61)
Gas-St10	1,680	10	(0.00)	0.6%	0.72	14	7	30	19	(23)	(41)
Gas Turb	1,738	87	0.00	5.0%	6.21	49	31	7	47	11	(36)
Gas CC	2,235	1,674	(0.00)	74.9%	0.33	518	391	29	133	97	(36)
Gas/Oil Steam	2,300	498	2.28	21.6%	23.12	183	147	35	41	1	(40)
Gas/Oil Turb	649	7	0.00	1.2%	0.16	8	4	5	4	(1)	(5)
Coal 1	2,878	2,245	(0.00)	78.0%	0.00	694	257	76	72	360	288
Coal 2	991	724	0.00	73.0%	0.00	224	139	39	97	45	(52)
Diablo Canyon	2,160	1,734	0.00	80.3%	0.00	536	107	191	717	238	(479)
Palo Verde	1,046	840	0.00	80.3%	0.00	260	58	69	280	133	(148)
San Onofre	2,150	1,726	0.00	80.3%	0.00	533	129	202	571	203	(368)
Oil plants	827	4	(0.00)	0.5%	0.30	8	3	3	10	1	(8)
Geotherm	1,534	820	0.00	53.5%	0.00	253	76	122	122	56	(66)
IPP-1	2,034	1,017	-	50.0%	0.00	314	348	22	238	(55)	(294)
IPP-2	2,034	1,017	-	50.0%	0.00	314	375	22	285	(83)	(368)
IPP-3	1,497	749	0.00	50.0%	0.00	231	296	16	244	(81)	(326)
IPP-Renewable	2,646	1,720	-	65.0%	0.00	532	603	38	340	(108)	(448)
Hydro Limited	9,573	4,180		43.7%		1,426	25	103	242	1,297	1,055
Total Generation	56,768	26,604	23		84.35	8,537	5,042	1,254	3,684	2,241	(1,443)

Appendix Table C-4. ORCED Results for Nothwest Hydroelectric Output 20% Lower

	Northwest	California	Combined				Northwest	California	Combined
						~Market price, ¢/kWh	4.53	4.55	4.54
Reserve Margin	30.4%	17.2%	33.3%			Full-cost-based Price	2.27	3.94	3.12
pretrade LOLP, % of period	75.6986	1.4629		Transmission		Producer price, ¢/kwh	4.55	4.52	4.53
Load factor	69.4%	59.0%	68.9%	MW Capac.	7,000	Variable Cost	0.84	2.02	1.46
Peak Demand, MW	39,954	48,432	88,386	Fee, ¢/kWh	-	Avoidable Cost	1.41	2.50	1.98
Energy Demand, GWh	242,844	250,148	492,992	paymt, M$	-	Total Cost	2.21	3.92	3.11
Wholesale Sales, GWh	2,258	11,112	13,370	Losses, %	0%	Costs w/ Unserved, M$			
Wholesale Purch, GWh	(11,112)	(2,258)	(13,370)	Lost GWh	0	Variable+Start-up Cost	2,016	5,318	7,337
Generation, GWh	234,390	258,831	493,221	Lost M$	-	Avoidable Cost	3,342	6,573	9,914
Unserved Energy, GWh	(399)	170	(229)	Total M$	-	Total Cost	5,231	10,257	15,488
Capacity Factor	51.3%	52.0%	51.7%	Peak trans	5338.45	Total Consumer Cost	11,039	11,459	22,497
						Producer earnings re Avoi	7,357	5,231	12,588

RESULTS FOR NORTHWEST

Plant Name	Capacity MW	Generation MWyr	Wholesale Sales, MWyr	Capac Factor	Time on Margin, %	Revenue M$	Var. +Start Cost M$	Avoidable Fxd Cst M$	Unavoid. Fxd Cst M$	Net Revenue, M$ Avoidable	Total
Coal 1	430	348	-	80.9%	0.00	135	21	14	12	99	87
Coal 2	619	555	-	89.6%	0.00	215	38	15	14	162	147
Coal 3	798	646	-	80.9%	0.00	250	48	59	37	143	106
Coal 4	805	754	-	93.7%	0.00	292	55	18	28	219	191
Coal 5	992	888	-	89.5%	0.00	344	79	23	78	241	163
Coal 6	1,145	926	-	80.9%	0.00	359	81	33	145	245	100
Coal 7	243	210	-	86.5%	0.00	81	20	6	15	55	40
Coal 8	1,252	1,078	-	86.1%	0.00	417	109	25	61	283	223
Coal 9	626	506	0.00	80.9%	0.00	196	53	14	29	128	99
Coal 10	700	566	-	80.9%	0.00	219	65	18	16	137	121
Coal 11	689	557	-	80.9%	0.00	216	72	11	14	133	118.64
Coal 12	697	564	-	80.9%	0.00	219	77	11	11	130	118.30
Coal 13	393	318	-	80.9%	0.00	123	43	10	37	70	32.97
Coal 14	380	307	-	80.9%	0.00	119	46	8	32	65	32.52
Coal 15	532	430	23.26	80.9%	0.01	167	89	14	70	64	(5.94)
IPP-1	1,084	951	-	87.7%	0.00	368	173	11	64	184	119.59
IPP-2	1,084	1,001	-	92.3%	0.00	388	219	11	48	158	109.56
WNP 3	1,100	883	-	80.3%	0.00	341	64	90	329	187	(141.78)
Gas Steam	1,187	1,037	162.56	87.4%	0.52	402	225	18	16	160	144.07
Gas CC	1,186	1,072	-	90.4%	0.00	415	170	16	30	229	198.72
Gas GT 1	693	475	71.97	68.5%	6.95	208	117	7	15	85	70.23
Gas/Oil GT2	290	7	0.01	2.4%	0.92	30	7	5	0	19	18.63
Geotherm	23	18	0.00	80.0%	0.00	7	1	4	7	3	(4.19)
Steam Other	467	190	0.00	40.7%	0.00	73	25	14	44	35	(9)
IGCC	105	92	0.00	87.7%	0.00	36	8	5	25	22	(3)
Hydro Limited	34,591	12,377		36%	0.00	5,036	71	864	711	4,101	3,390
Total Generation	52,110	26,757	258		8.39	10,657	1,977	1,323	1,890	7,357	5,467

RESULTS FOR CALIFORNIA

Plant Name	Capacity MW	Generation MWyr	Wholesale Sales, MWyr	Capac Factor	Time on Margin, %	Revenue M$	Var. +Start Cost M$	Avoidable Fxd Cst M$	Unavoid. Fxd Cst M$	Net Revenue, M$ Avoidable	Total
Gas-St1	2,221	1,521	0.01	68.5%	0.00	543	307	32	25	204	179
Gas-St2	1,630	1,034	0.00	63.4%	0.14	369	220	29	33	119	86
Gas-St3	2,021	1,268	3.03	62.7%	0.75	455	290	30	23	134	111
Gas-St4	1,964	1,214	18.86	61.8%	2.41	437	286	16	17	135	119
Gas-St5	2,022	1,212	53.96	59.9%	2.33	441	286	28	34	128	93
Gas-St6	1,500	855	64.84	57.0%	5.83	317	205	13	19	99	80
Gas-St7	2,348	1,226	149.96	52.2%	9.71	469	297	26	18	146	128
Gas-St8	2,345	808	336.70	34.4%	16.61	366	202	25	20	138	118
Gas-St9	2,743	294	145.36	10.7%	15.07	248	90	45	32	113	80
Gas-St10	1,680	58	26.13	3.5%	5.98	106	27	30	19	49	30
Gas Turb	1,738	423	196.33	24.3%	19.64	245	115	7	47	122	76
Gas CC	2,235	1,676	(0.00)	75.0%	0.00	597	329	29	133	239	105
Gas/Oil Steam	2,300	1,116	238.23	48.5%	8.91	463	277	35	41	151	110
Gas/Oil Turb	649	47	25.35	7.3%	1.46	58	17	5	4	36	32
Coal 1	2,878	2,245	(0.00)	78.0%	0.00	800	257	76	72	467	395
Coal 2	991	724	0.00	73.0%	0.00	258	139	39	97	79	(18)
Diablo Canyon	2,160	1,734	0.00	80.3%	0.00	618	107	191	717	320	(396)
Palo Verde	1,046	840	0.00	80.3%	0.00	299	58	69	280	172	(108)
San Onofre	2,150	1,726	0.00	80.3%	0.00	615	129	202	571	285	(286)
Oil plants	827	24	9.69	2.9%	0.96	65	16	3	10	46	36
Geotherm	1,534	820	0.00	53.5%	0.00	292	76	122	122	94	(28)
IPP-1	2,034	1,017	-	50.0%	0.00	364	293	22	238	49	(189)
IPP-2	2,034	1,017	-	50.0%	0.00	364	316	22	285	26	(259)
IPP-3	1,497	749	0.00	50.0%	0.00	268	249	16	244	2	(242)
IPP-Renewable	2,646	1,720	-	65.0%	0.00	617	603	38	340	(23)	(363)
Hydro Limited	9,573	4,180		43.7%		2,028	25	103	242	1,900	1,658
Total Generation	56,768	29,547	1,268		89.81	11,704	5,219	1,254	3,684	5,231	1,547

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