EXHIBIT NO. ______ (EAH-1T)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: ERIC A. HIRST

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DIRECT TESTIMONY OF ERIC A. HIRST
ON BEHALF OF PUGET SOUND ENERGY, INC.

NOVEMBER 26, 2001

PUGET SOUND ENERGY, INC.

DIRECT TESTIMONY OF ERIC A. HIRST

Q: Please state your name and business address.

A: My name is Eric A. Hirst. I am a consultant specializing in electric-industry restructuring. My business is located at 106 Capital Circle, Oak Ridge, Tennessee 37830.

I. INTRODUCTION

Q: Would you please provide a description of your educational and professional experience?

A: Yes. I provide this information in Exhibit EAH-2.

Q: Would you please provide a description of your experiences that qualify you to testify in the current proceeding?

A: Yes. I provide this information in Exhibit EAH-2.

Q: Have you acted as a witness in any other utility proceedings?

A: Yes. I have appeared before several state regulatory commissions and the Federal Energy Regulatory Commission in both litigated and rulemaking proceedings. During the past 20 years, I have testified before the regulatory commissions in Washington, DC, Illinois, Idaho, Colorado, Arizona, and Washington.

Q: What is the purpose of your testimony?

A: My testimony focuses on the regional power supply and T&D benefits of dynamic electricity pricing.

Q: What are your conclusions?

A: I conclude that PSE's Time-of-Use ("TOU") pricing programs and other forms of price-responsive demand programs can provide regional power supply benefits in the range of

$100 to $700 million for the year 2003. (The region here is defined as Oregon and Washington.) In a year like 2000, these benefits would be much higher because electricity prices were much higher and much more volatile than in "typical" years. These differences in the economic benefits from dynamic pricing illustrate the important insurance value of these programs—their benefits are greatest when the need is greatest These programs also provide regional transmission and distribution benefits (i.e., capital cost avoided), which range from $25 to $75 million a year.

II. REGIONAL BENEFITS OF DYNAMIC PRICING

Q: What is dynamic pricing?

A: Dynamic pricing is a general term that encompasses a variety of retail pricing options. These options provide price signals to customers that are better aligned with the cost of producing and delivering electricity to those customers than are traditional rate designs. Retail-pricing options span a broad spectrum, anchored at one end by traditional rate designs. These designs feature a guaranteed, fixed price for unlimited quantities of electricity, with the price set well in advance (typically one or more years) of actual consumption. The other end of the pricing spectrum is anchored by a simple pass-through to retail customers of hourly wholesale electricity prices. Seasonal and TOU rates are intermediate points on this spectrum. Customers are much better able to manage price and volume risks than are their suppliers because customers can modify the timing and amount of their electricity use in response to these price signals. Of course, if customers see only time-invariant prices, they have no incentive to and no information on whether, when and how to modify their electricity use to reduce power costs.

Q: What benefits do dynamic pricing provide?

A: The answer encompasses three categories: economic efficiency, reliability, and environmental quality.[1] With respect to economic efficiency, the essence of competition is to expand the range of customer choices. Offering customers a variety of pricing options is an essential component of competitive markets and a key to improving customer well-being. Customers who choose dynamic pricing can lower their electricity bills in two ways: (1) by avoiding hedge costs (i.e., self-insuring) and (2) by shifting electricity use away from high-price periods to low-price periods. Retail customers who modify their usage in response to prices reduce price volatility by lowering the magnitudes of price spikes. And these reductions in price spikes benefit all retail customers, not just those who modify their consumption in response to changing prices. Finally, the benefits of dynamic pricing are greatest when wholesale electricity prices are most volatile.

Customers who choose dynamic pricing and respond to those prices provide valuable reliability services to the local control area. The North American Electric Reliability Council noted that to "… improve the reliability of electric supply, some or all electric customers will have to be exposed to market prices … ."[2] Specifically, load reductions at times of high prices (generally caused by tight supplies) provide the same reliability benefits as the same amount of additional generating capacity. From the reliability perspective, a reduction in demand is equivalent to an increase in generation.

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[1] E. Hirst and B. Kirby, *Retail-Load Participation in Competitive Wholesale Electricity Markets*, Edison Electric Institute, Washington, DC, and Project for Sustainable FERC Energy Policy, Alexandria, VA, January 2001.

[2] North American Electric Reliability Council 2000, *Reliability Assessment 2000-2009*, Princeton, NJ, October.

Indeed, to the extent the demand reduction is spread among many (perhaps thousands) of customers, diversity enhances the reliability benefits of load reductions.[3]

Finally, strategically timed demand reductions decrease the need to build new generation, transmission, and distribution facilities. When demand responds to price, system load factors improve, increasing the utilization of existing generation and reducing the need to build new facilities. Higher asset utilization should lower overall electricity costs. Avoiding, or at least deferring, such construction improves environmental quality. Cutting demand at times of high prices may also encourage retirement of aging, inefficient, and polluting generating units.

Q: Have you performed an analysis of the regional benefits of dynamic pricing programs?

A: Yes.

Q: Would you please discuss the context of your analysis and the concept of demand elasticity?

A: Yes. It is important to offer retail customers time-varying electricity prices because wholesale electricity prices are inherently volatile. Prices are so volatile for several reasons:

- Generators differ substantially in their costs to produce electricity (e.g., the running costs for hydro and nuclear units are typically well below $10/MWh, while the cost for an old combustion turbine might be $100/MWh or more).
- System loads vary from hour to hour (e.g., by a factor of two to three during a single day).

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[3] A large generator that provides reliability services (e.g., 100 MW of 10-minute reserves) that trips offline provides no reliability benefit. It is very unlikely that hundreds or thousands of customers who, together, provide 100 MW of reserves would all fail to respond at the same time.

- Electricity cannot easily be stored and therefore must be produced and consumed at the same time.
- Sudden generator outages, transmission outages, extreme weather conditions, and other events can trigger unexpected imbalances between generation and demand; rebalancing the electrical system can be expensive.
- Intertemporal constraints limit generator flexibility so that at certain low-load hours the price can be zero or negative because it costs more to turn a unit off and turn it on again later than to keep it running.
- When unconstrained demand exceeds supply, the price is set by consumer demand at a level above the running cost of the most expensive unit then online. During these few, high-load hours, generators must bid prices above their running costs to recover their startup and no load costs.

When customers choose electricity prices that vary temporally (from hour to hour, from one block of hours to another, from day to day, and from season to season), they receive important economic signals. These signals, if they are delivered to customers in a timely fashion, let them know when it is cheap to produce electricity (and they might want to use more) and when it is expensive (and they might want to use less). Any changes in the timing of electricity use associated with these temporal price signals lower electricity costs to those customers. In addition, these load-shape changes reduce the frequency and magnitude of wholesale-power price spikes, leading to additional economic benefits enjoyed by all electricity consumers, not just those with dynamic prices.

The extent to which customers respond to changes in electricity price is measured through a concept economists call elasticity. Basically, the price elasticity of demand for electricity is the percentage change in electricity use caused by a 1 percent change in price. Because demand increases when prices go down and vice versa, the elasticity values for electricity are almost always negative.

Q: What did you consider in developing your estimates of elasticity for purposes of your analysis?

A: I estimated elasticities based on the Brattle Group's analysis of electricity-consumption data for PSE customers on the TOU rate relative to those who were receiving the information-only (PEM) program.[4] During the morning and evening periods, when prices were higher by 15%, consumption was down 4.5%, leading to an elasticity of -0.33. During the overnight period, when prices were lower by 11%, consumption was higher by 5.4%, leading to an elasticity of -0.45.

PSE, based on the Brattle report, used a value of -0.35 for the residential sector. Based on a literature review, PSE used an elasticity of -0.20 for the commercial/industrial sector. Because my analysis of regional effects dealt with retail load in general and not with individual customer classes, I used the average of these two values (-0.275) in the analysis reported below.

Q: What did you use as a basis to estimate the potential regional power-supply benefits?

A: PSE provided me results from an analysis conducted with the Aurora model for the year 2003. These results included hourly loads and wholesale electricity prices for Oregon and Washington, one of the 13 markets in the Western Systems Coordinating Council (WSCC) included in the Aurora analysis.

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[4] The Brattle Group 2001, *An Evaluation of the Impacts of Puget Sound Energy's Time-of-Day Program*, Cambridge, MA, October 25.

Q: How did you use these estimates of elasticity and power supply to conduct your analysis?

A: I first calculated an hourly *retail* price based on the hourly *wholesale* price projections noted above. Specifically, I added a $30/MWh T&D adder to the Aurora wholesale prices to obtain the corresponding retail prices. I used the same value for time-of-use elasticity that PSE used in its analysis of PSE-specific results (-0.275) and an assumed fraction of regional retail load that chooses dynamic pricing (with values set to 0.1, 0.2, and 0.3). I then calculated the change in retail load in Oregon and Washington for every hour of the year.

Q: Please explain your assumptions with respect to the percentage of customers in Oregon and Washington participating dynamic pricing programs?

A: I chose modest participation values for three reasons. First, not all consumers, even in the long run, will choose dynamic pricing. Second, during the first few years of such programs, not all utilities will be offering such choices to their customers and those utilities that do offer dynamic pricing will likely not offer such choices to all their customers at once. Third, I want to develop results that are conservative (i.e., show fewer regional benefits than might actually occur). Finally, my analysis does not account for the feedback loops between customer response to dynamic prices and investor construction of new power plants. As the share of customers choosing dynamic pricing increases, the reductions in retail load and in wholesale electricity prices will grow to the point that power plants that otherwise would have been built will not be built. This reduction in the construction and operation of new power plants would likely provide substantial regional environmental benefits.

Q: Please explain your assumptions with respect to hourly loads and prices?

A: I then used an assumed power-supply curve to calculate the change in wholesale electricity price caused by the change in retail demand discussed above (Fig. 1). (This curve is based roughly on the bids submitted to the California Power Exchange; results for the New York, New England, and PJM markets show very similar curves.) This curve shows that the price of electricity increases only modestly as demand increases when regional supplies are ample relative to demand. However, when supplies are tight (at the right side of the graph) small increases in demand lead to very large increases in electricity prices.

The net result of this analysis is two sets of hourly loads and prices, one without dynamic pricing (i.e., assuming all customers have a time-invariant, fixed price for electricity) and one with dynamic pricing. Finally, I calculated annual electricity costs for retail customers with and without customer response to changes in hourly electricity prices. (To simplify comparisons of results, I set annual electricity consumption in both cases equal. That is, I ignored any conservation benefit of dynamic pricing in this analysis.) Because this model, although very simple, contains many factors that are far from certain, I ran several sensitivity cases. In particular, I varied the fraction of customers that choose dynamic pricing from 10% to 30% and the size of the regional market in which Oregon and Washington exist from 50,000 MW (roughly the size of the Northwest Power Pool) to 150,000 MW (roughly the size of the WSCC).

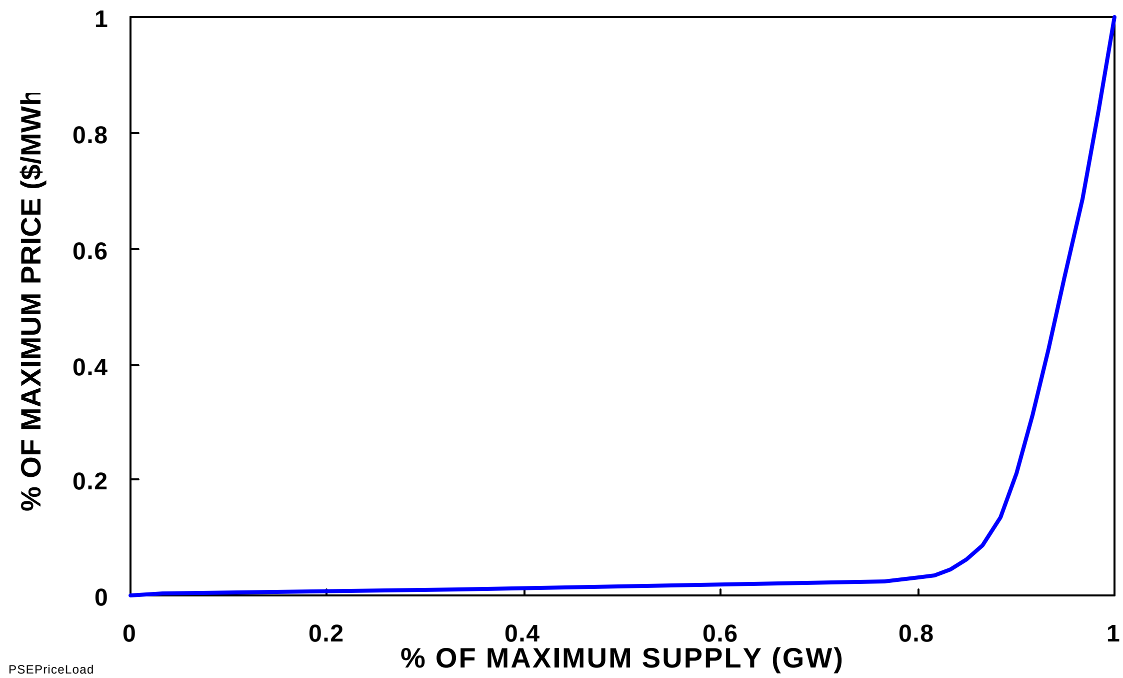

Fig. 1. Assumed power-supply curve showing the relationship between the wholesale price of electricity and the supply of electricity.

Q: What results did you obtain with this simulation model?

A: The Aurora model results show an average hourly consumption for the Oregon/Washington retail load of 18,700 MW and an average wholesale electricity price of $31.0/MWh. Thus, the annual wholesale energy cost for these two states is $5.16 billion. Hourly loads and prices are weakly correlated, with a correlation coefficient of 0.43.

Like all such production-costing models, the Aurora model does not fully reflect the volatility of electricity prices that wholesale markets exhibit. Specifically, the standard deviation of the hourly prices from the Aurora model is $7/MWh, 23% of the mean value. By comparison, the standard deviation of mid-Columbia prices in 1999 was almost $13/MWh, 53% of the mean value. The standard deviation of hourly day-ahead prices in the New York ISO energy market was 52% of the mean price from

December 1999 through October 2000. The comparable percentages were 59% for the PJM day-ahead energy market from June 2000 through July 2001 and about 60% for the California Power Exchange market in 1999. Aurora's inherent inability to fully estimate price volatility leads to an understatement of the benefits of dynamic pricing. To address this aspect of the model, I multiplied the Aurora hourly prices by a random factor that left the average price unchanged but increased the standard deviation to 50% of the mean value.

Figure 2 shows how the savings vary with changes in the fraction of customers choosing dynamic pricing and the size of the regional market. As the fraction increases and the size of the market decreases, the benefits increase. Also, as the volatility (e.g., standard deviation) of electricity prices increase, the benefits of dynamic pricing increase. Under my base-case assumptions (fraction = 0.2 and regional market = 100,000 MW), annual wholesale electricity costs are cut by 5%, equivalent to about $280 million a year (Table 1). Using the original, low-volatility prices that Aurora produced yields an annual savings of 1.4%, equivalent to about $80 million a year.

Table 1. Reduction in annual electricity costs (million $) for Oregon and Washington in 2003 because of dynamic pricing as a function of the fraction of customers participating and the size of the regional electricity market[a]

	Regional Electricity Market (MW)			Low Volatility
Fraction of Customers Participating	50,000	100,000	150,000	100,000
0.1	269	147	105	41
0.2	503	284	204	80
0.3	702	411	299	118

[a]The total annual wholesale electricity cost is $5.2 billion.

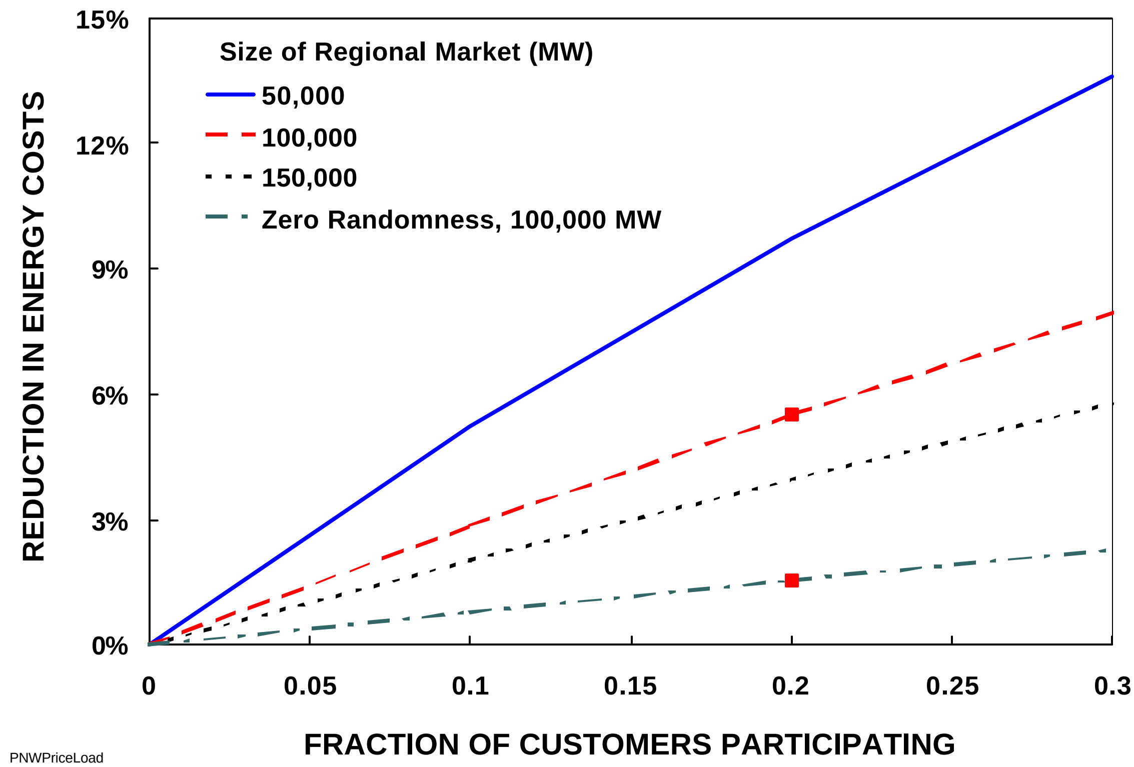

Fig. 2. Percentage reduction in wholesale energy costs in Oregon and Washington for 2003 as a function of price elasticity of demand and the size of the regional electricity market. (The two points represent the base cases considered here.)

Q: What factors lead to these results?

A: When hourly electricity prices are high, consumers with dynamic pricing will reduce their consumption of electricity. On the other hand, when prices are low, those consumers will increase their electricity use. (These general statements are fully supported by the results obtained from the first four months of PSE's TOU implementation.) These shifts in electricity use—away from high-price periods and to low-price times—benefit customers who make those changes in the timing of their electricity use.

But that is not the complete story. Reductions in electricity use during high-price periods lower wholesale electricity costs. Referring to Fig. 1, when prices are high, the supply curve is very steep, meaning that a small reduction in electricity use at such times can have a dramatic effect on lowering electricity prices. On the other hand, consumers increase consumption when prices are low, and this increase in consumption yields a movement up the supply curve (at the lower left of Fig. 1). However, the price increases during low-price periods are much less than the price reductions during high-price periods. Thus, overall electricity prices are lowered. All consumers, not just those facing dynamic prices, benefit from these price reductions. The results in Fig. 2 reflect the total regional effect, encompassing both customers who choose dynamic pricing and those who do not. As the size of the retail load choosing dynamic pricing relative to the size of the region decreases, the effect of these dynamic responses to changing electricity prices is diminished.

Q: How do you interpret the numbers you presented above?

A: I estimated the effects of dynamic pricing (i.e., having retail customers face hourly wholesale electricity prices) on (1) retail electricity use (i.e., changes in hourly loads and their effects on load shapes) and (2) wholesale electricity prices. I ran cases for Oregon/Washington for the year 2003 with different assumptions on the fraction of retail load that chooses dynamic pricing, the size of the regional wholesale power market, and the volatility (but not the average value) of wholesale electricity prices. Table 1 shows the estimated dollar benefits of dynamic pricing for the cases analyzed here.

The results, assuming a level of volatility typical of that found in other competitive electricity markets, show savings that range from 2% of annual wholesale power costs to almost 14%. The results obtained with the original Aurora prices show annual savings that are about 30% of those discussed above. This comparison raises a very important point. Consumers benefit from dynamic pricing not just when electricity prices are high. They benefit, perhaps even more, when prices are volatile.

The analyses discussed above show a large range in the benefits associated with dynamic pricing (Fig. 2). When wholesale electricity prices are especially high and volatile and when hourly loads are highly correlated with those prices, the benefits of dynamic pricing are very high. On the other hand, if wholesale electricity prices are moderate, if they are stable, and if retail loads are only weakly correlated with those prices, the benefits of dynamic pricing are much lower. Thus, the benefits of dynamic pricing, as modeled, are greatest when the need is greatest. Calculating the benefits and costs of dynamic-pricing programs should consider this very valuable insurance aspect. It protects customers and their wholesale supplier from catastrophe when wholesale prices are especially high and volatile, for example, during dry-water and high-natural-gas price periods.[5] An even greater benefit, that is not captured by the model, is the avoided costs of preventing volatile situations from occurring in the first place.

Q: What benefits might dynamic pricing provide during a year like 2000?

A: I have not analyzed this situation. However, I am confident that the benefits of dynamic pricing would greatly exceed those shown in Table 1 for 2003. On average, regional wholesale electricity prices in 2000 were triple those projected for 2003 ($99 vs. $30/MWh). And the volatility of prices in 2000 was much greater than that projected for 2003 (standard deviation of $114 vs. $15/MWh). As discussed above, the benefits of dynamic pricing increase as wholesale prices increase and as they become more volatile. Because electricity prices were both higher and more volatile in 2000 than expected for 2003, the benefits of dynamic pricing would have been much greater in 2000.

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[5] Ignoring the insurance benefits of dynamic pricing would be akin to considering one's life-insurance premium a waste of money if the policyholder didn't die that year.

Q: Are there regional transmission and distribution (T&D) benefits associated with dynamic-pricing programs?

A: Yes. Utilities that own, operate, and maintain T&D systems must expand these systems. For transmission, such capital investments are driven by the need to comply with reliability requirements and the need to move increasing amounts of power from generators to retail loads (i.e., to respond to growth in retail demand). Distribution capital investments are driven by growth in the number of customers and growth in retail demand. To the extent that dynamic pricing encourages retail customers to reduce demands when the T&D systems would otherwise be heavily loaded, such programs reduce the need for these capital investments.

In addition, load reductions in the Pacific Northwest will reduce the local utility's transmission charges for use of the Bonneville Power Administration transmission system. This charge is $1.24/kW-month.[6]

Q: Did you quantify these regional benefits?

A: Yes. I assumed that nonreliability T&D investments are driven primarily by peak demands. To estimate the effects of a dynamic-pricing program on peaks, I calculated the reduction in demand associated with the pricing program for those hours when mid-Columbia electricity prices were the highest. I chose the top 1% of the hours because I did not want these results to depend on the load reductions for one hour or even a few hours.

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[6] BPA is beginning a major transmission-construction program. The first nine projects alone have an estimated capital cost of $615 million (Infrastructure Technical Review Committee 2001, *Upgrading the Capacity and Reliability of the BPA Transmission System*, August 30). Dynamic-pricing options, such as PSE's TOU program, could defer the need for some of these capital expenditures.

PSE provided data on its annual capital expenditures for transmission integration, transmission growth, and distribution growth for each year from 1990 through 2000.[7] The company also provided data on peak demand each year. Using these data, I calculated an average capital cost per kW of demand growth over this decade:

Transmission = $126/kW

Distribution = $225/kW

I converted these capital costs to annual amounts using a 15% fixed charge rate. I assumed that these PSE-specific capital-cost figures are roughly representative of the region as a whole. Based on this assumption, the annual transmission benefit from a 1-MW load reduction at the time of highest regional electricity prices is then $26,800 ($126/kW × 0.15 + $1.24/kW-month × 12). The annual distribution benefit from a 1-MW load reduction is $33,700.

Table 2 shows the T&D benefits based on the cases discussed above. Consistent with the power-supply results, the T&D benefits vary substantially, depending on the fraction of customers choosing dynamic pricing and the volatility of wholesale electricity prices. For the cases considered here, the T&D capital-reduction benefits are about 15% of the power-supply benefits. They equal $38 million a year for the base case.

Table 2. Reduction in annual T&D capital costs (million $) for Oregon and Washington in 2003 because of dynamic pricing as a function of the fraction of customers choosing dynamic pricing and the volatility of

[7] These investment amounts do not include capital expenditures for reliability, e.g., automatic switches and circuit breakers, and SCADA systems for transmission; nor do they include the costs of replacing worn-out or obsolete equipment on the PSE distribution system, or capital expenditures for regional transmission improvements to path ratings between control areas.

wholesale electricity prices[a]

Fraction of Customers Participating	Normal volatility	Low volatility
0.1	19	10
0.2	38	20
0.3	56	29

[a]The total annual wholesale electricity cost is $5.2 billion.

Q: Does this complete your testimony?

A: Yes.

[BA013160001]

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PUGET SOUND ENERGY, INC.

PROFESSIONAL QUALIFICATIONS OF ERIC A. HIRST

Q: Would you please provide a description of your educational and professional experience.

A: Yes. I obtained a Ph.D. degree in Mechanical Engineering from Stanford University in 1968. Since then, I have been a college professor at Tuskegee Institute and, from 1970 through 2000, a researcher at Oak Ridge National Laboratory (ORNL). I was on special assignments four times during my 30-year tenure at ORNL: with the Federal Energy Administration in Washington, DC; with the Minnesota Energy Agency in St. Paul, MN; with Puget Power (now Puget Sound Energy, PSE) in Bellevue, WA; and with the Land and Water Fund, a regional environmental law center in Boulder, CO. I was appointed a Corporate Fellow at ORNL in 1985, a distinction shared by only 1% of the ORNL technical staff. In January 1997, I formally opened a consulting practice on issues related to the many changes under way in the U.S. electricity industry.

Q: Would you please provide a description of your experiences that qualify you to testify in the current proceeding?

A: Yes. Between 1995 and 2000, I directed the Electric-Industry Policy Studies Group at ORNL. The group analyzed some of the many issues related to a restructuring U.S. electricity industry. Since January 1997, I have been actively consulting on many of these issues. My current and recent projects deal primarily with bulk-power operations, reliability, and markets, including ancillary services, generation and transmission adequacy, transmission planning, integration of wind resources into wholesale markets and operations, and analysis of price-responsive demand.

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