EXHIBIT NO. ______ (WAG-1T)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: WILLIAM A. GAINES

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DIRECT TESTIMONY OF WILLIAM A. GAINES ON BEHALF OF PUGET SOUND ENERGY, INC.

NOVEMBER 26, 2001

PUGET SOUND ENERGY, INC.

DIRECT TESTIMONY OF WILLIAM A. GAINES

I. INTRODUCTION

Q: Please state your name, business address, and position with Puget Sound Energy, Inc.?

A: My name is William A. Gaines. My business address is 411 108th Avenue N.E., Bellevue, Washington 98004. I am Vice President Energy Supply for Puget Sound Energy, Inc. ("PSE", or the "Company").

Q: Have you prepared an Exhibit describing your education, relevant employment experience, and other professional qualifications?

A: Yes, I have. It is Exhibit WAG-2.

Q: What are your duties as Vice President Energy Supply for PSE?

A: My responsibilities include planning and management of the Company's power and natural gas supply portfolios, and associated bulk transmission and transportation arrangements.

II. SUMMARY OF TESTIMONY

Q: Please summarize the contents of your testimony?

A: The following is a description of the organization and content of my testimony:

Section I – Introduction

Section II – Summary of Testimony

Section III – PSE's Approach to Energy Supply describes the Company's power and natural gas supply portfolios and how they have been managed since its last general rate filings. Since 1992, the Company has adjusted and improved its base electric power and natural gas resource portfolios, reducing or offsetting certain projected costs.

Section IV – Normalized Power Costs describes the approach taken by the Company in preparing its projection of normalized power costs presented in this case, and an illustrative range of its power costs given alternative hydroelectric and energy market price conditions. I also provide a description of the Aurora production cost model utilized by the Company in making its projections. Finally, I describe an illustrative range of values of the power supply and certain other benefits estimated to be derived from the Company's Personal Energy Management Program (PEM), given a projection of the impacts of PEM on the Company's loads.

Section V – Situational Background for Energy Supply contrasts the regulated cost-based wholesale energy supply market environment within which the Company operated through the time of its last electric and gas general rate filings against the competitive wholesale energy supply market environment within which the Company must operate today and in the future. I also quantify historical, current and future cost volatility in PSE's power supply portfolio.

Section VI – Cost Volatility Drivers in PSE's Energy Supply Portfolios describes the primary factors that contribute to cost volatility in the Company's power and natural gas supply portfolios.

Section VII – Customer Choice and Price Signaling in Retail Rates summarizes the rate structures historically in place for recovery of the Company's energy commodity costs, and the basis for the power and natural gas retail rate alternatives proposed by the Company in this case.

Section VIII – Power Cost Tracker Rates and Hedged Rates describes the specific power cost tracker rates and hedged rates proposed by the Company in this case.

III. PSE'S APPROACH TO ENERGY SUPPLY

Electric

Q: Please describe the components of the Company's electric supply portfolio?

A: The Company maintains a diverse portfolio of power supply resources – including long-term contracts for purchases from Mid-Columbia hydro projects, the Company's own hydro projects located in or near the Company's service territory, other long-term purchase and exchange contracts, Colstrip coal-fired generation, combined-cycle gas and oil fired generation in the Company's service territory and simple-cycle gas and oil fired combustion turbine generation in the Company's service territory. In addition, the Company participates in the wholesale power market, balancing its resource portfolio to its loads.

The Company's power supply portfolio provides a diverse mix of resource and fuel types and cost and operating characteristics. This mix avoids undue reliance on any one particular type of power source. The Company's mix of resources with different fixed and variable costs allows the Company to respond to, or ameliorate, the effects of various loads and market supply and cost conditions. The Company's power supply portfolio is described in greater detail in Exhibit WAG-3.

Q: Please describe how the Company has managed its electric supply portfolio since its last general rate filing in 1992?

A: During that period, the Company adjusted and improved its base electric power resource portfolio, reducing or offsetting certain projected electric power costs and moving toward a more dynamic power supply. These adjustments and improvements included the following:

(i) restructuring the 94 MW long-term purchase contract with Montana Power Company;

(ii) restructuring the Encogen and Tenaska natural gas-fired cogeneration project contracts;

(iii) selling the Company's 93.8 MW interest in the Centralia coal-fired powerplant;

(iv) acquiring two new 53 MW simple-cycle combustion turbines, Fredonia Units 3 and 4;

(v) entering into the Amended Settlement Agreement with the Bonneville Power Administration (BPA), which provided for increased residential purchase and sale benefits from BPA for the Company's residential and small farm customers.

These activities and their background are described in more detail in Exhibit WAG-4.

In a settlement of a dispute over delivery provisions in the 94 MW long-term purchase of power from the Montana Power Company, PSE was able to increase the amount of the purchase by 3 MW, substantially lower the fixed contract payments, remove an annual load factor cap on energy deliveries under the contract and achieve reductions in its Colstrip coal fuel costs.

In the Encogen restructuring, the project was purchased and one of the project's three fixed price gas supply contacts was bought out. In the Tenaska restructuring, five of the project's fixed price gas supply contracts were bought out. These restructurings and the sale of Centralia were cost-effective, resulting in projected electric power cost reductions. The Encogen and Tenaska restructurings preserved the basic power supplies from these projects, enhanced their operational flexibility, changed long-term, high fixed price gas contracts to a more dynamic market priced supply and provided projected power cost savings. The Centralia sale also reduced operational, environmental and mine reclamation risks.

The Company's installation of Fredonia Units 3 and 4 in 2001 provided a number of benefits. These units provide physical generating capacity needed to help meet PSE's extreme winter peak loads. In that regard, this acquisition provides capacity approximately equal to the capacity of Whitehorn Unit 1 and the Whidbey Island simple cycle combustion turbines, which have been retired. Like those two units, the Fredonia Units 3 and 4 have the advantage of being located in the Company's service area**,** which promotes efficiencies in maintenance and operation and also promotes service reliability. However, compared to the Whitehorn and Whidbey units, the Fredonia Units 3 and 4 are much newer, more efficient and more reliable, and they operate with greater flexibility and fewer emissions.

The PSE-BPA Amended Agreement monetized the power portion of PSE's new residential and small farm exchange benefits over a five-year period (October 1, 2001 through September 30, 2006). The total amount of exchange benefits under the PSE-BPA Amended Agreement (as monetized) to be passed through for the time period July 1, 2001 through September 30, 2006, is estimated to be more than $800,000,000, which is a significant increase over the benefits of less than $240,000,000 received from BPA for the Company's residential and small farm customers for the immediately preceding five-year period.

<u>Gas</u>

Q: Please describe the components of the Company's natural gas supply portfolio?

A: The Company maintains a diverse portfolio of gas supply resources – including long-term firm, short-term firm, and non-firm gas supplies from a diverse group of suppliers and supply basins. For baseload and peak-shaving purposes, PSE supplements its firm gas supply portfolio by purchasing natural gas at generally lower prices in summer, injecting it into underground storage facilities and withdrawing it during the winter heating season. Storage facilities at the recently expanded Jackson Prairie in Western Washington and at Clay Basin in Utah are used for this purpose. The Company's gas supply portfolio is described in greater detail in Exhibit WAG-3.

Q: Please describe how the Company has managed its natural gas supply portfolio since its last general rate filing in 1995?

A: The most significant change in the Company's natural gas supply portfolio since its last general rate filing is the completion in 1999 of an expansion of the Jackson Prairie natural gas storage facility. This expansion provides a cost effective source of peaking supply needed to serve retail customer demand. The Company's one-third share of this increased storage capacity and increased injection/withdrawal capability has reduced the quantity of annual peaking supply contracts required in the portfolio. This expansion and its background are described in more detail in Exhibit WAG-4.

IV. NORMALIZED POWER COSTS

Q: Please describe how the Company has projected its normalized pro forma net power costs in this case?

A: As in prior general rate cases, adjustments were made to test year (the 12 months ending June 30, 2001) power cost data. The effect of these adjustments is to develop projected power costs for the rate year (the 12-month period beginning October 1, 2002). The resulting projected power supply costs were then adjusted to test year levels by multiplying by an adjustment factor of 0.9716, which reflects the ratio of test year weather normalized delivered energy loads to rate year weather normalized delivered energy loads.

As has been previously advocated by Commission Staff, the Company has utilized an hourly dispatch model to project its normalized net power costs for the rate year. PSE has utilized the Aurora model, which is a fundamentals based hourly production cost model – i.e., it relies upon factors such as supply, demand, and transportation that drive resource operations and prices in the electric power market. Aurora uses hourly demand and individual resource operating characteristics in a transmission constrained, chronological dispatch algorithm for the entire WSCC area. For modeling purposes, the WSCC is divided into thirteen areas and the economic dispatch for each area is determined based on the loads and resources in each area and its transmission interconnection capacity with other areas. Through balancing the economic dispatch among all of the areas, an hourly market clearing price is determined. A full description of the Aurora model is included as Exhibit WAG-5.

To adapt Aurora to produce projected net power costs for the PSE system, the Company and Aurora vendor EPIS have made the following extensions and database updates to the model:

1. Developed generation output data for Northwest hydroelectric projects for each of the 60 water-years of record based on the Northwest Power Pool Final 2000-2001 Regulation. Specific generation data was developed for each of the 5 Mid-Columbia hydroelectric projects from which the Company purchases power as well as the Company-owned hydroelectric projects.
2. Developed additional portfolio contract types to simulate the cost calculations of the non-utility generating (NUG) power purchase contracts.
3. Updated the Aurora WSCC database to include resources projected to come on-line through 2004.

4. Developed the data and databases to include the Company's load and resources as a specific "Portfolio" within the Oregon/Washington/North Idaho dispatch area. To define a Portfolio within Aurora it is necessary to: (a) identify the specific generating resources to be allocated to the Portfolio, (b) define the power purchase and sales contracts included in the Portfolio, and (c) provide forecasts of the monthly loads as well as the hourly shape of the loads for the Portfolio.

An important input to the Aurora model is the forecast of natural gas prices, since Aurora computes the market clearing price for power based upon the marginal generator in each hour of the dispatch simulation and that marginal generator is typically gas fueled. To project natural gas prices for the rate year, the Company adopted the forward market prices for natural gas as of September 28, 2001. Of course, these forward market prices will vary during the course of this rate case (and afterward) and are one of the sources of variability in the Company's power costs.

Q: What historical streamflow record has the Company used in its "expected value" normalized net power cost projection?

A: The Company has prepared projections of its net power costs using both a 40-year and a 60-year streamflow history. In prior orders the Commission has required the electric utilities under its jurisdiction to utilize the 40-year streamflow record over the period 1948-49 through 1987-88 in their power cost projections. However, the Commission has also recognized that other periods may be demonstrated to be more valid. The Company has engaged Dr. Charles R. Nelson, Professor of Economics and Statistics at the University of Washington, to review the 60 years of available streamflow data for the Columbia River system over the period 1928-29 through 1987-88. Professor Nelson has a Ph.D. in economics and specializes in time series econometrics and statistics. Essentially, Dr. Nelson's work reveals that there is no discernable trend in the 60 years of streamflow data, that the data are normally distributed, and that there is no serial correlation in the data. From this Dr. Nelson concludes that there is no statistical basis to exclude any of the available historical streamflow data, and that the best "expected value" forecast of streamflow is the simple average of all of the available 60 years of historical data. Dr. Nelson's qualifications and the results of his work are included as Exhibit WAG-6.

Q: What hedge costs has the Company included in its projection of normalized net power costs?

A: As discussed in Section VII of this testimony and in Exhibit WAG-8, the Company has designed and has estimated the cost of various hedges against power cost volatility and has included those estimated hedge costs as a component of its projected normalized power costs.

Q: Please quantify the Company's "expected value" normalized net power cost projection?

A: Based on the 40 years of streamflow data, the Company's expected value projected rate year net power costs are $765.3 million and based on the 60 years of data they are $773.6 million. The Aurora model results for these studies are included in Exhibit WAG-7. Power costs based on the 40 years of streamflow data were utilized to develop the revenue requirement presented in this case. However, based on the results of Dr. Nelson's work and for the reasons summarized above, the Company proposes that the Commission allow it to use the 60 years of available data to project its expected value net power costs.

Q: Please quantify the range of variation in the Company's net power cost projection?

A: An illustrative range of the Company's net power costs for the rate year October 2002-September 2003 is shown in the table below, based on Aurora model results. The table displays a range of net power costs based on varying assumptions as to streamflow and as to the market price of natural gas (and in turn, power). Streamflow variation assumptions include a "dry" year (1988), a "moderate" year (1969), and a "wet" year (1959). The range of market price variation is derived from the implied volatility of the forward market gas prices described above, and illustrates a 95% confidence interval around the forecast prices. In turn the Aurora model uses this range of gas prices to determine the market clearing power price. This approach is not intended to indicate the entire potential range of impacts of gas and power prices on the Company's projected net power costs, but rather is an illustration based on market price volatilities as of the week ending September 28, 2001.

Projected Rate Year Net Power Costs ($ Millions)

		-------------------Streamflow Condition-------------------			
		Dry	Moderate	Wet	Range
Market Price	High	909.7	829.5	750.1	159.6
	Moderate	814.6	764.0	713.6	101.0
	Low	710.2	690.4	666.7	43.5
	Range	200.0	139.0	83.5	243.0

Q: Has PSE evaluated the costs and benefits of the PEM Program?

A: Yes. The results of the cost benefit analysis are further described in the testimony of Penny J. Gullekson. The estimated benefits of PEM over a 10-year period have a net present value (NPV) in the range set forth in the table below, based on the results of a PEM net benefits model.

PSE prepared a model that evaluated the costs and benefits of PSE's PEM program over a 10-year program life and summarized the result using NPV. The model simulated alternative assumptions about reduction of energy consumption and shifting of energy consumption (shift of consumption from relatively high peak periods to relatively low peak periods). In addition, the model was run through a range of market price conditions, using static analysis and Monte Carlo sampling, providing a distribution of estimated NPV of PEM.

The range of market price variation in the model is derived from the implied volatility of the forward market power prices, and illustrates a 95% confidence interval around the forecast prices.

The model considered the effects of reduced and shifted Company loads on power supply costs, on transmission and distribution investment and on third-party (BPA) wheeling expense. The model used the estimates presented by Penny J. Gullekson in her testimony of PEM costs and the reductions and shifts in the Company's loads under PEM, and also used the estimated levels of reductions in transmission and distribution investment presented by Susan McLain in her testimony.

The results of the PEM net benefits model analysis are summarized as follows:

Results of PEM Net Benefits Model Analysis (NPV $ x millions)

	Energy Reductions and Shifts		
	High Load	**Base Load**	**Low Load**
Lowest Forecast Price	$106.2	$9.0	- $70.0
Mean – Static Analysis	$152.8	$48.8	- $36.7
Mean – Monte Carlo	$163.3	$58.8	- $27.2
Highest Forecast Price	$363.4	$235.3	+ $125.8

Q: Have there been extraordinary circumstances that affect the Company's power costs that are not reflected in test year power costs?

A: Yes. The power costs for the test year (July 2000 through June 2001) rates are developed on a projected, normalized basis – reflecting projected, normalized power costs for the period October 2002 through September 2003 (the rate year). Therefore, the effects of the extraordinary circumstances experienced prior to the rate year are not reflected in the power costs used in setting rates.

Q: Please describe these extraordinary circumstances and their effect on power costs.

A: These extraordinary circumstances occurred during the period of about May 2000 through July 2001 and included the following.

(i) Market power prices rose (and power supply availability in the region tightened) dramatically. Natural gas market prices rose as well, but the increases were not as drastic as the increases in spot market power prices.

(ii) Subsequently during this period, market power prices collapsed even more dramatically. Natural gas market prices also declined.

(iii) Market power prices experienced unprecedented volatility.

(iv) Hydroelectric generating conditions in the region were the second worst on record.

The cumulative effect of these extraordinary circumstances has been to undermine the Company's ability to offset escalating basic power supply costs with margins from off-system market power sales. The Company's basic power supply costs have been and are increasing substantially (notwithstanding the recent drop in wholesale spot market power prices). The high market power prices during the period mid-2000 to mid-2001 enabled the Company to offset these escalating basic power supply costs by allowing the Company to sell surplus power at a high price.

More fundamentally, the spark spread was very large during this period. (In general, the spark spread represents the amount by which the spot market power price exceeds the variable operating cost of a natural gas-fired generator.) The large spark spread during this period allowed the Company to economically operate its simple cycle combustion turbines which, because of the high spark spread, could generate electricity at a cost far below the then-prevailing market price. (These simple cycle combustion turbines are an important element of the Company's power resource portfolio and are available to meet extreme peak demand during cold weather and to provide back-up supply in the event of poor hydroelectric conditions.) During the mid-2000 to mid-2001 period, the Company's simple cycle combustion turbine operated at a high capacity factor, and the high spark spread allowed these units to operate at a cost well below the then-prevailing market price and thereby helped offset the escalation in the Company's basic power supply costs. By contrast, a number of other utilities were forced to seek substantial rate increases during that period.

Faced with extraordinary volatility and high prices in the wholesale market in the mid-2000 to mid-2001 timeframe, the Company also secured fixed price commitments for natural gas supply for the generation the Company needed to have available for its retail loads.

The ability of the Company to use the high spark spread during the mid-2000 to mid-2001 period to offset escalating base power supply costs was particularly important in light of the merger Rate Plan. The volatility and level of wholesale market prices during that period far exceeded the historic volatility that had been experienced at the time of the agreement of the parties to the Rate Plan and under the Company's merger order in 1997.

The ability of the Company to use surplus sales to offset the escalation of the Company's basic power supply costs unexpectedly changed when wholesale market prices and the spark spread experienced an extraordinary decline in the summer of 2001. The consequences of these events are affecting the Company's power costs to the point where the Company is currently underrecovering its power costs by an average $625,000 per day over the 13-month " period September 2001 through September 2002.

Q: Have you quantified the amount of the Company's unrecovered power costs during the period of the extraordinary circumstances that you have described?

A: Yes. I have quantified the Company's unrecovered power supply costs in <u>Exhibit WAG-9</u>. That exhibit compares the normalized projected power costs reflected in the Company's rates during the period September 2001 through September 2002 with the actual and projected power costs of the Company during such period.

V. SITUATIONAL BACKGROUND FOR ENERGY SUPPLY

<u>Electricity Market – Traditional Cost Based Market Structure</u>

Q: Please describe the characteristics of Western wholesale power markets as they existed at the time of the Company's last general rate filing in 1992?

A: Over the past several decades, electric utilities became increasingly interconnected with one another for the purpose of improving reliability. Cost based wholesale power markets developed to facilitate cost reductions through economy transactions which took advantage of diversity in load and generation characteristics. Prior to passage and implementation of the National Energy Policy Act of 1992 (NEPA-92), wholesale electricity markets were essentially the exclusive domain of electric utilities that owned and operated generation and transmission facilities. Rates for wholesale sales of electricity by jurisdictional "public utilities" were regulated by the Federal Energy Regulatory Commission (FERC) and were limited to the fully allocated cost of the facilities utilized to provide service. Due to the typical availability of excess supply resulting from reserve margins maintained by utilities, wholesale electricity purchase and sale transactions were frequently conducted at prices only slightly above the variable operating costs of the marginal generating unit, and significantly below full cost of service.

Q: What power cost variability did the Company face in this market environment?

A: Many of the drivers of power cost variability faced by the Company in that historical environment were the same as those faced by other utilities across the country. These included <u>volume</u> related risks such as streamflow related variability in hydroelectric production, generating unit forced outages, and the risk of temperature related variations in customer load. Each of these risks typically exposed the Company to the need to acquire replacement power in the regulated, cost based wholesale market. Other, price related power supply cost risks included variability in the price of the anticipated level of wholesale market purchases and sales of power, and variability in the market price of the anticipated level of fuel purchases for electric generation.

However, it is important to note that because of the large proportion of hydroelectric generation in the Pacific Northwest and in the Company's own supply portfolio, PSE faced unique and significantly greater volume related exposure to the effects of streamflow variability on hydroelectric production as compared to other utilities outside the Pacific Northwest region. In turn, this regional hydroelectric variability affected wholesale market prices, driving them higher during the low streamflow periods when PSE needed to be in the market purchasing replacement power. Conversely, wholesale market prices were typically lower during high streamflow periods when PSE might have surplus hydroelectric generation to sell.

Finally, in connection with each of these risks, the financial impact on PSE was magnified because the cost of replacement power or hydrocarbon fuel purchases at wholesale market rates was much higher than the "expected value" (or normalized) costs of the Company's supply resources. That was due to the large difference between (i) the low variable operating costs of PSE's hydroelectric and baseload coal generation and (ii) the market price of replacement power. This situation was exacerbated by the escalation in hydrocarbon fuel prices (and in turn wholesale power prices) that resulted from the "oil crises" of the 1970s.

Electricity Market – Recent Developments

Q: What changes have occurred in Western wholesale power markets since the Company's last general rate filing?

A: Today's markets bear little resemblance to those that existed just a few years ago. Through FERC orders implementing the provisions of NEPA-92 and its Order 888, FERC has required owners of electric transmission facilities to make them available to any eligible customer and to price the service at rates no higher than cost. Further, upon a simple demonstration of the lack of market power, FERC has allowed entities under its jurisdiction to sell power at competitive wholesale market rates, thus effectively scrapping the decades long cost based regulation of wholesale electric markets. These developments have spawned the formation and entry into the competitive wholesale markets of literally hundreds of new non-traditional participants, including power marketing and trading companies, generation developers, financial institutions, and others. These new participants have brought with them sophisticated commodity trading tools and techniques, as well as standardized and custom financial derivative products. Liquid and transparent "forward" wholesale markets for electric power have developed, and the volume of transactions in all these products and markets has skyrocketed. Reflecting in part the character and objectives of the new entrants, prices have been very volatile and have appeared at times to be disconnected from market fundamentals.

Following the deregulation and competition introduced into wholesale power markets by NEPA-92 and the FERC orders has been market restructuring and deregulation at the retail level in some (but not all) states. This retail deregulation proceeded to a different degree, at an uneven pace and with differing rules in different parts of the country. Uncertainty as to the timing and pace of deregulation and as to the respective roles and responsibilities of various entities in newly restructured environments has, among other things, made it difficult for entities to make commitments to new generating capacity for fear that the costs of those commitments might become "stranded." This has contributed to decreased reserve margins and a tightening of the supply/demand balance in the Western markets, in turn contributing to wholesale price volatility

Further, the California retail restructuring effort has significantly affected the Western wholesale power and natural gas markets. The misalignment of volatile market driven wholesale power prices and rigid retail rate structures dramatically increased utilities' unrecovered power costs and led one of the country's largest utilities into bankruptcy.

<u>Gas Market</u>

Q: Please describe developments in the Western markets for natural gas?

A: Deregulation in the natural gas markets began with the Natural Gas Policy Act of 1978, which provided for the gradual deregulation of wellhead gas prices. This was followed by a series of FERC orders beginning in 1985 which ultimately required natural gas pipelines to offer open access transportation service separate from the traditional sales of transportation bundled with the gas commodity itself, which pipelines had historically provided to Local Distribution Companies (LDC's) and other customers. As transportation-only service began to predominate, FERC regulation of the gas commodity price was further relaxed. These developments enabled entry into the market of non-traditional participants such as trading and marketing companies, financial institutions, and others. Many of these are the same companies that are the new entrants into the deregulated wholesale power markets, and many of the tools and techniques developed for the gas market were brought to the power market as well.

Q: What has been the effect of this new market environment on the Company's power cost variability?

A: Because the mix of power supply generating resources and contracts in the Company portfolio has changed relatively little from that which existed at the time of the Company's last general rate filing in 1992, the primary drivers of power cost volatility remain the same: hydroelectric production variability, generating unit forced outage risk, temperature related load variation, and market price risk related to power and natural gas purchases and sales. However, as discussed in my testimony, the market environment against which these factors play out has changed significantly.

Historical Actual Power Cost Variability. As an indicator of this power cost volatility based on actual experience in 2000-2001, one need only look at the Company's test year net power costs presented in this case. In particular, the Company's actual test year net power costs were more than $100 million higher than its normalized rate year net power costs (net of hedge costs) in this case. Because of the previously described changes in the wholesale markets, it must be assumed that this volatility can recur.

Current Power Cost Variability. The volatility in wholesale energy markets has significantly increased PSE's actual and projected 2001-02 power costs. Among other things:

- During the first half of 2001, a number of significant events beyond the Company's control affected significant net power costs. Hydro conditions at the Company's Mid Columbia facilities continued to deteriorate, from an initial forecast in January of 2001 of 77% of normal, to a forecast of only 57% of normal by July 1, 2001, a historical low. Beyond this, the Company experienced forced outages and other operating limitations at its thermal generating units, further reducing the availability of reliability of low cost generation.

- This increased exposure to the market occurred at a time of significant and unprecedented increases in forward power and gas market prices and greatly increased the cost to serve retail load and severely diminished the Company's ability to offset its power cost with sales of surplus power at high market prices.
- In 2001, the Federal Energy Regulatory Commission ("FERC") instituted price "mitigation" or caps in the spot wholesale power markets throughout the West. This was followed by a precipitous decline in both spot and forward market power prices. These wholesale price caps and the subsequent decline of spot and forward energy market prices deprived the Company of the value previously available from sales of power that offset the cost of poor hydro and other cost pressures in the supply portfolio.

Future Power Cost Variability. PSE's exposure to power supply risk going forward is substantial, as illustrated above by the range of projected annual net power costs of $243 million for the rate year. PSE’s heightened exposure is the result of:

(i) its dependence on regional hydro conditions,

(ii) the increase in the volatility of western region power prices;

(iii) the deterioration in supply/demand conditions in the West precipitated by limited growth in capacity; and

(iv) the uncertain ongoing administrative structure of the western power markets as highlighted by the FERC price caps, imposed in 2001.

VI. COST VOLATILITY DRIVERS IN PSE'S ENERGY SUPPLY PORTFOLIOS

Electric

Q: Please describe the drivers of volatility in PSE's power supply costs?

A: The Company's power supply portfolio contains a diverse mix of resources with widely differing operating and cost characteristics. There are many complex risks and options embedded in the portfolio; however, the four major volume and price drivers of power cost volatility, each of which arises from factors that are beyond the Company's control, are described below:

Hydro. During an average streamflow year, approximately 35% of the Company's electric energy production is from hydroelectric sources. In an average year, the Company's hydroelectric resources provide approximately 7,700,000 MWH of energy (approximately 6,300,000 MWH from long-term purchases from Mid Columbia hydroelectric projects and approximately 1,400,000 MWH from production at PSE’s owned Westside hydroelectric resources). However, under very dry or very wet conditions, production from these resources can vary from approximately 5,600,000 to approximately 9,800,000 MWH annually. The Company has no control over the effects of weather on streamflow and hydroelectric production. Further, since much of this hydroelectric production is at "run of river" projects with only insignificant reservoir storage capacity, the Company has little or no control over the timing of the generation.

To serve its customer load and to balance and economically optimize its supply portfolio, the Company must either acquire replacement power during poor streamflow conditions or dispose of surplus power during favorable streamflow conditions. These balancing transactions are conducted in the wholesale power markets. Because at the margin the Company always faces the wholesale market power price and because the market price is volatile, the amount and timing of hydroelectric shortfalls or surpluses can greatly affect the costs incurred for replacement power.

Hydro supply and timing uncertainty, and the Company's exposure to the cost of replacement power when hydro supply is low and the Company's ability to offset costs through secondary sales when hydro is abundant, are weather related, depending upon precipitation (amount and distribution) and temperature (which affects shape of natural run-off), and are beyond the Company's reasonable control.

Forced outages. The Company relies on more than 2,000 MW of thermal generating units to help meet its customer loads. These units include approximately 700 MW of large baseload coal generators with low variable operating costs, approximately 700 MW of relatively efficient natural gas fueled combined cycle combustion turbine cogenerators, and approximately 600 MW of relatively less efficient simple cycle natural gas fueled combustion turbine generators. Forced outages at these generating units are typically related to material or equipment failure, fire, electrical disturbances, or other force majeure events beyond the Company's control. (While forced outages at hydroelectric generating projects can limit operational flexibility, they often do not result in significant reductions in the volume of energy produced as do thermal unit forced outages due to the multiplicity of units typically available at hydroelectric projects and the typical excess of project hydraulic capacity compared to available streamflow.)

The degree to which forced outages at any of these thermal generation facilities create cost volatility in the Company's power supply portfolio is based on the relationship of the variable operating cost of the unit forced out of service to the market price of replacement power over the duration of the outage. For the coal units, this risk is almost always significant since their variable operating costs, based on long-term coal supply contracts, are typically well below the market price of replacement power. For the cogeneration and simple cycle combustion turbine units, this risk can range from nil to very significant, depending upon the relationship between the market price of natural gas and the market price of power. That is because these gas fueled units always face the market cost of gas either due to displacement of the cogeneration facilities or due to the reliance on market-priced gas supply for the simple cycle combustion turbines.

The Company's costs of replacement power in the event of forced outages are weather related, because the costs of replacement power are a direct function of market prices, which as discussed herein, are weather related. In that regard, both the occurrences of forced outages and the costs of replacement power in the event of forced outages, are beyond the Company's reasonable control.

Load/Temperature Uncertainty. Because in the Pacific Northwest there is a high saturation of electric space heating (relative to other areas of the country), the level of the Company's retail electric load is closely related to temperature. The Company has no control over the effects of weather and temperature on retail electric load.

On a daily basis, the Company's electric load can vary up or down by as much as 1000 MWH for each one degree change in temperature. The average temperature in the Company's service area for a winter month can vary as much as plus or minus eight degrees, and the average temperature in the Company's service area for a winter day can vary as much as much as plus or minus thirteen degrees.

Any deficiency or surplus of power supply caused by temperature related load variation must be purchased or disposed of in the wholesale power markets, thus creating widely varying exposure to short-term market prices.

Particularly in light of the significant electric heating load in the Company's service territory, the Company's cost of load/temperature uncertainty is weather related and beyond the Company's reasonable control.

Market Prices. Even absent the foregoing volume related risks which affect the amount of the Company's exposure to market prices, the Company has significant price related risk associated with the expected volume of its purchases and sales of power in the wholesale markets and associated with its need to purchase or dispose of natural gas in connection with the operation of its gas fueled generating units. For example, the Company's Aurora analysis projects that, to serve its electric customers, the Company expects during the rate year to purchase and sell approximately 1,500,000 MWH of power in the wholesale power markets and to purchase approximately 32 BCF of gas in the natural gas markets.

The Company's costs of purchases and sales on the secondary market are weather-related, because two major drivers of secondary market prices are temperature (market prices are higher during relatively hot and relatively cold weather) and precipitation (e.g., market prices are relatively higher when hydro supply on the West Coast is relatively low). Further, considering that the Company is a very small participant in the overall Western power market, and is essentially a "price taker", market prices are beyond the Company's reasonable control.

<u>Gas</u>

Q: Please describe the drivers of volatility in PSE's natural gas supply costs?

A: The Company's gas supply portfolio is composed of a mix of supply contracts from various producing areas including the Western Canadian Sedimentary Basin, the Rocky Mountain area, and the San Juan Basin. There are many risks and options embedded in the portfolio; however the two major volume and price drivers of gas cost volatility are described below:

<u>Load/Temperature Uncertainty</u>. Because of the high saturation of natural gas space heating in the Pacific Northwest, the level of the Company's retail natural gas demand is closely related to temperature. The Company has no control over the effects of weather on temperature and retail natural gas demand.

On a daily basis, the Company's retail natural gas demand can vary up or down by as much as 14,000 MMBtu for each one degree change in temperature. Any deficiency or surplus of natural gas supply caused by temperature related load variation must be purchased or disposed of in the wholesale gas markets (or injected or withdrawn from storage), thus creating widely varying exposure to short-term market prices.

Particularly in light of the significant natural gas heating load in the Company's service territory, the Company's cost of load/temperature uncertainty is weather related and beyond the Company's reasonable control.

<u>Market Prices</u>. Even absent the foregoing <u>volume</u> related risk which affects the amount of the Company's exposure to market prices, the Company has significant <u>price</u> related risk associated with the <u>expected</u> volume of its purchases and sales of natural gas in the wholesale markets. Essentially all of the Company's gas supply contracts have similar pricing provisions, based on the monthly price index for the particular supply basin. Hence the primary driver of cost volatility in the natural gas supply portfolio -- which arises from factors that are beyond the Company's control -- is the index price of gas at the various supply points. For example, to serve its natural gas customers in this case, the Company expects to purchase and sell approximately 74 BCF of natural gas in the wholesale markets.

The Company's costs of purchases and sales in the natural gas market are weather-related, because a major driver of gas prices is temperature (market prices are typically higher during relatively cold weather). Further, considering that the Company is a very small participant in the overall Western gas market, and is essentially a "price taker", market prices are beyond the Company's reasonable control.

VII. CUSTOMER CHOICE AND PRICE SIGNALING IN RETAIL RATES

Q: What retail electric rate structures were in place for PSE in the previous regulated, cost-based wholesale power market environment?

A: Beginning more than 20 years ago, commissions across the country recognized the adverse effects of fuel price escalation and variability on their utilities and put in place fuel cost adjustment clauses (many of which continue in effect to this day). Similarly the Washington Utilities and Transportation Commission ("Commission") recognized that the range of power cost variability, stemming from the characteristics of PSE's supply portfolio and its market environment, was a circumstance beyond the Company's control, and recognized that therefore costs driven by these factors should be recoverable through a power cost tracker. Power cost adjustment mechanisms have a long history of application in the State of

Washington. They began for PSE 21 years ago when the Commission approved a two-month "interim power cost adjuster" in Cause No. U-80-77. The Commission said this adjuster was "designed to recover, through an increase in rates, those power costs which exceed variable power costs presently being recovered through currently effective rates." WUTC v. Puget Sound Power & Light Co., Docket No. U-80-77, Second Supplemental Order, at 2 (1980). For purposes of this tracker, variable power costs were defined as

> *costs which vary with water conditions, loads and fuel costs. They include the cost of purchasing power from other utilities; the costs of purchasing oil, natural gas, and coal to operate generating resources powered by such fuels; and the costs of stored energy generated or purchased in prior periods and held for current use, less credits from the sale of surplus power to other utilities*.

Id. (emphasis added). In its findings of fact, the Commission concluded as follows:

> Respondent's financial indicators reveal that without additional revenues to offset reliably forecasted excess variable power costs, its overall rate of return and return on common equity will be well under levels heretofore found to be required; further, its earnings per share will be below its current dividend . . . [and] the severe financial burden posed by short-term variable power costs must be offset by immediate recovery through rates in order to maintain respondent's financial integrity.

Id. at 6.

This temporary power cost adjuster was replaced by a broad, permanent Energy Cost Adjustment Clause (ECAC) in the Company's next general rate case, Cause No. U-81-41. In that case, the Commission struggled with what it called the *"most troublesome contested issues in this proceeding . . . those relating to appropriate means of rate-case accounting for net energy costs."* The Commission's solution was to implement the ECAC. <u>WUTC v. Puget Sound Power & Light Co.</u>, Docket No. U-81-41, Second Supplemental Order at 15 (1982) (emphasis added).

This mechanism served the Commission, the Company and its customers for nearly a decade. The first ECAC rate went into effect on June 1, 1982, and the final ECAC rate was authorized on October 8, 1990. Rates were set 25 times during this period. The rates resulting from this mechanism ranged from a credit of 0.223 cents per kWh to a charge of 0.543 cents per kWh.

The decade of the '90s saw a refinement in the type of power cost tracking mechanism approved by the Commission, the new Periodic Rate Adjustment Mechanism (PRAM). The initiative in this case was a Commission issued Notice of Inquiry (NOI), issued May 9, 1990.

In response to this NOI, PSE entered into discussions with Commission Staff and other parties to develop a mechanism. The result was the PRAM. This mechanism included an annual adjustment to recover power costs and the decoupling of revenues (other than variable power costs) from the level of the Company's retail sales. The Commission described this portion of the mechanism in the order approving the mechanism and the first rate adjustment as a "periodic rate adjustment mechanism, annually applied." <u>WUTC v. Puget Sound Power & Light Company</u>, Docket Nos. UE-901183-T and UE-901184-P, at 5 (1991). Under the company's proposal, "'resource' costs . . . are recovered in a manner intended to make the Company whole for certain types of expenses related to energy resource acquisition." <u>Id.</u> at 6. Resource costs included "variable power supply costs, production O&M expenses, production rate base, and conservation costs." Id. at 12. As the Commission described it in a subsequent order, "[t]he mechanism is similar to the prior energy cost adjustment clause (ECAC) mechanism in that it sets up a deferred account allowing a reconciliation of revenue and expenses that are subject to hearing and review." In re Petition of Puget Sound Power & Light Company, Docket Nos. UE-920433, UE-920499, UE-921262, Eleventh Supplemental Order, at 6 (1993).

The first rate adjustment under this mechanism went into effect on October 1, 1991. The last rate adjustment under this mechanism, PRAM 5, was implemented on October 1, 1995, with the final deferral related to PRAM ending mid-year 1997. Through the PRAM adjustment mechanism and the ECAC adjustment mechanism, the Company has recovered certain power costs through a tracker mechanism for 14 of the last 20 years.

Q: What retail natural gas rate structures were in place for PSE in the evolving natural gas market environment?

A: Even before the aforementioned deregulation of natural gas markets and unbundling of pipeline transportation and sales service began, escalation of Canadian gas prices in the mid-1970s prompted the Commission to put in place for the LDC's under its jurisdiction Purchased Gas Adjustment (PGA) mechanisms which allowed actual gas costs to be passed through to retail rates through a periodic deferral accounting mechanism. These mechanisms have remained in effect through the period of development of competitive gas markets and are in widespread use throughout the country to track wholesale gas price volatility. Similarly, mechanisms to track wholesale electric price volatility are needed as competitive wholesale electric markets develop and price volatility increases.

Q: Please describe the basis for the form of retail energy rates being proposed by the Company in this case?

A: As described above, the nature of the Company's power and natural gas supply portfolios and their interaction with the volatile wholesale power and natural gas markets lead to a very significant degree of volatility in the Company's energy supply costs. As discussed in my testimony, there are two primary ways in which this can be addressed:

(i) reflect the volatility of power costs (through a tracker) in retail rates so that customers can make informed consumption decisions, or

(ii) include in retail rates the costs of hedging against the volatility of power costs, which protects the retail rates against volatility but which deprives the retail customers of a price signal which, as discussed in the testimony of Dr. Peter Fox-Penner, allows customers to make informed decisions.

The Company is proposing that customers be allowed to choose between a "tracked" rate which would reflect the short-term variations in the Company's energy costs and a "hedged" rate which would provide a known rate for the commodity component of their service over the period of the hedge.

Further, the Company is offering a green power rate. To the extent customers elect the green power rate, the Company will purchase “Renewable Energy Credits” (RECs) or “Green Tags” from a third party that can verify that its transaction supports a renewable energy source. The source of energy may include wind, solar, geothermal, biomass, and low-impact hydro. Purchases of the tags help ensure that power from non-polluting resources is produced. Such production can replace power from a hydrocarbon burning resource such as a coal or natural gas plant, resulting in less SO_2 or CO_2 pollution. A portion of the

Green Tag revenue to the third party goes toward investment in new renewable resources that further increase the region's diversity of energy resources.

The Company is also proposing modification of its tariffs to address new loads over 5 MW. Under this proposal, the customer would pay the incremental cost to the Company of procuring power to serve a new load (or increase in load) in excess of the greater of 5 MW or 110% of the customer's historical demand with pricing reflective of the nature of the customer's load and purchase commitment. This incremental pricing would continue until such time as the Commission determined that a different cost allocation approach for such load was appropriate. Customers with such new large loads should pay such an incremental cost because such loads can develop very quickly and are not encompassed within the normal planning process. This proposal ensures that in the short-run new large loads do not impose significant risks and costs on the Company's other customers and ensures that in the long-run the Commission will have the opportunity to address the appropriate allocation of the costs and risks of such loads.

Electric – Tracked Rates

Q: Please describe the basic approach to the Company's proposed tracked electric rates?

A: As discussed earlier, there are four basic drivers of cost volatility in PSE's electric supply portfolio – hydro, forced outages, load/temperature uncertainty and market price. Rates with a properly designed tracker, at a minimum, should

(i) track the cost volatility attributable to these drivers;

(ii) recover the fixed or "non-tracked" components of power supply costs;

(iii) send price signals to customers; and

(iv) allow customers the choice of a tracked or hedged rate.

These volatility drivers are reflected in the following electric supply cost components: secondary purchase costs, fuel costs, and secondary sales revenues. The basic approach of the Company's proposed tracked electric rate is to send price signals and track costs and revenues in rate components that are based on these cost components.

The Company's proposed tracked electric rate is linked to power cost factors that, as discussed earlier, are weather related and are due to events beyond the Company's reasonable control.

Q: How do the components of the tracked rates relate to the Company's electric commodity costs and give signals to the customers about such costs?

A: As described in detail in the testimony of the Company's rate design witnesses in this case, the commodity related components of the tracked electric rate include:

1. A fixed component to recover customer, transmission, distribution, and certain fixed and variable power costs of the Company. The power costs in this component are determined on a projected and normalized basis.
2. A variable component to recover certain other variable costs of the Company's power supply resources on an actual basis, including the cost of natural gas fuel for electric generation and the cost of short-term purchases of power in the wholesale markets. This component would be projected and rates re-set on a monthly basis, with a subsequent true-up to actual costlevels as recorded in certain of the Company's FERC sub-accounts. This component signals variations in fuel costs and secondary purchase costs.
3. A variable component that reflects the price of power in the daily Pacific Northwest power market, so that marginal changes in customer consumption would benefit by the true value of the power conserved. This

component would be projected and rates re-set on a daily basis, with a subsequent true-up to actual power costs attributable to this component. This component signals variations in secondary market prices.

4. A variable component (credit) which reflects and returns to customers benefits from sales of surplus power in the wholesale power markets. This component would be projected and rates re-set on a monthly basis, with a subsequent true-up to actual revenues and costs for such sales. This component signals variations in secondary sales margins.

<u>Electric – Hedged Rates</u>

Q: Please describe the basic approach to the Company's proposed hedged electric rates?

A: The Company, together with a consultant, Castlebridge Partners, has designed and obtained preliminary indicative cost information for certain hedge transactions which would reduce the volatility associated with the four major drivers of power cost volatility described in this testimony. (It should be noted that it may not be possible for the Company to obtain hedges that would offset all of its power cost volatility or even to offset all of the volatility associated with any one of the four major drivers described in this testimony.) A full description of these hedges, along with indicative cost information, is included as <u>Exhibit WAG-8</u>. A summary of these hedges follows:

<u>Hydro</u>. To offset the effect on costs of hydro variability, PSE would implement a "swap and call" strategy whereby PSE would pay a premium in exchange for being made whole for excess power costs during below-normal stream-flow periods but would also agree to deliver to the swap counterparty any benefits from above-normal stream-flow periods. The above swap structure would include PSE's receiving payment when high water flows would likely result in spilling water and thereby reducing the amount of hydro generation available for PSE to deliver to the counterparty.

<u>Forced Outages</u>. To offset the effect on costs of forced thermal plant outages, PSE would purchase outage insurance to offset increased power costs for the duration of any forced outage. The hedge structure provides for a payment to PSE based on the market price of power at the time of the outage.

<u>Load/Temperature Uncertainty</u>. To offset the effect on costs of load/temperature uncertainty, PSE would purchase a string of dual trigger "put" and "call" options. These options would hedge risks of (1) a surplus in resources due to lower than expected retail loads and low wholesale market prices and (2) a deficit in resources due to higher than expected retail loads and high wholesale market prices. The string of dual trigger "put" options provide benefit when the temperature rises above the temperature strike level <u>and</u> the price of Mid-C power drops below the price strike level. The string of dual trigger "call" options provide benefit when the temperature drops below the temperature strike level <u>and</u> the price of Mid-C power rises above the price strike level.

<u>Market Prices</u>. While the foregoing hedges are expected to provide a significant reduction in the volume related volatility in power costs, they do not address volatility in power costs for the <u>expected</u> volume of power and natural gas fuel purchases and power sales at market prices. This volatility will be offset by executing forward contracts at fixed rates or by executing "fixed for floating" price swaps for these <u>expected</u> volumes.

During an annual election period, the Company will provide a projection of the hedged rate for the upcoming annual hedge period reflecting a then current projection of the Company's power costs based on then current projections of its loads and resources, market prices for power and natural gas, hedge costs and benefits, and other factors.

Customers that elect this hedged rate option during the annual election period will pay a rate based on this projection which will not vary due to power cost volatility during the upcoming annual hedge period. Any difference between the projected hedge cost and the actual hedge cost will be carried forward and included in the hedge cost for the subsequent year.

<u>Gas – Tracked Rates</u>

Q: Please describe the basic approach of the Company's proposed tracked gas rates.

A: As discussed above, there are two basic drivers of volatility in PSE's gas supply portfolio – load/temperature uncertainty and market price. Rates with a properly designed tracker, at a minimum, should

(i) track the cost volatility attributable to these drivers;

(ii) recover the fixed or "non-tracked" components of gas supply costs;

(iii) send price signals to customers; and

(iv) allow customers the choice of a tracked or hedged rate.

Q: Please describe the Company's proposal for recovery of natural gas commodity costs?

A: The Company proposes to continue the present Purchased Gas Adjustment (PGA) mechanism, with one important modification. Rather than the historical irregular periodic updates of the PGA rate, the Company would re-forecast its gas commodity costs and would adjust the PGA rate on a monthly basis, thereby providing customers with a more current price signal.

Gas – Hedged Rates

Q: Please describe the Company's approach to the hedged rate for natural gas commodity costs?

A: Similar to its proposal for recovery of electric commodity costs, the Company proposes as an alternative to the PGA rate an elective hedged rate which would reduce the volatility associated with the two major drivers of natural gas cost volatility described in this testimony. A full description of these hedges, along with indicative cost information, is included as Exhibit WAG-8. A summary of these hedges follows:

Load/Temperature Uncertainty. To offset the effect on costs of load/temperature uncertainty, PSE would purchase a string of dual trigger "put" and "call" options. These options would hedge risks of (1) a surplus in gas supply due to lower than expected retail loads and low wholesale market prices and (2) a deficit in gas supply due to higher than expected retail loads and high wholesale market prices. The string of dual trigger "put" options provide benefit when the temperature rises above the temperature strike level and the price of natural gas drops below the price strike level. The string of dual trigger "call" options provide benefit when the temperature drops below the temperature strike level and the price of natural gas rises above the price strike level.

Market Prices. While the foregoing hedges are expected to provide a significant reduction in the volume related volatility in gas costs, they do not address volatility in gas costs for the expected volume of gas purchases market prices. This volatility will be offset by executing forward contracts at fixed rates or by executing "fixed for floating" price swaps for these expected volumes.

During an annual election period, the Company will provide a projection of the hedged rate for the upcoming annual hedge period reflecting a then current projection of the Company's natural gas costs based on then current projections of market prices for natural gas hedge costs and benefits and other factors. Customers that elect this hedged rate option during the annual election period will pay a rate which is based on this projection and which will not vary due to gas cost volatility during the upcoming annual hedge period. Any difference between the projected hedge cost and the actual hedge cost will be carried forward and included in the hedge cost for the subsequent year.

<u>Hedge Limitations</u>

Q: Would the Company need additional rate relief if extreme conditions cause actual power costs to vary materially from the hedged costs?

A: Yes. The Company would need additional rate relief, but only in rare circumstances. In that regard, there are practical limits on the availability and effectiveness of reasonably priced hedges for various risks.

VIII. POWER COST TRACKER RATES AND HEDGED RATES

Q: Has the Company developed a proposed power cost tracker?

A: Yes. The overall rationale for the program is addressed earlier in my testimony. The implementation of the power cost tracker rates (and the hedged rates) through rate schedules is addressed by Mr. Heidell.

Q: Please review the differences between the power cost tracker and the power cost hedge.

A: Customers are provided an option to either have rate certainty through the Power Cost Hedge, or to have their rates subject to periodic adjustment through an accounting procedure to reflect the difference between actual and forecasted rate year costs for certain tracked power costs. Customers will make this selection on an annual basis and are not allowed to switch between the options except during an annual enrollment period. Customers selecting the Power Cost Tracker will have monthly rate adjustments, which reflect changes in the Company's variable power costs, and will also have a portion of their consumption price based on the estimated daily market price of power (with the rate for this portion subsequently trued up to track certain of the Company's actual power costs, to ensure that the Company does not over or under recover its power costs as a result of the market price signal). Each year the Company will inform customers about the two options including the cost of the fixed cost option, the length of the hedge period, and how to select each option.

Each option represents a different approach for customers and the Company to address variability and volatility in weather-related energy costs. Customers who select the hedged option are electing to pay rates reflecting the costs and benefits of certain power cost hedges; they are essentially buying an insurance policy. Customers who elect the tracked option will be informed about the expected cost and a likely range of costs.

Q: Please summarize the rate components of the power cost tracker?

A: Customers who take the tracked option will have 80% of their daily energy consumption (block 1) billed at rates based on three components:

(i) Fixed Cost Charge. This element is a ¢ /kWh charge based on customer, transmission, distribution, and certain fixed power costs.

(ii) Non-Tracked Power Cost Charge. This element is a ¢/kWh charge based on certain projected normalized power costs that are not subject to the power cost tracker.

(iii) Tracked Variable Power Cost Charge. This element is a ¢ /kWh charge based on certain projected normalized power costs that are subject to the power cost tracker.

(iv) Monthly Sales Credit. This component is a monthly ¢/kWh credit based on the estimated margin on secondary market power sales made by the Company.

(v) Hedge Cost Credit. This component is a ¢/kWh credit that removes the hedge costs that would otherwise be charged to customers who elect the tracked, rather than the hedged, option.

The remaining 20% of the daily energy consumption (block 2) of customers who take the tracked option will be billed based on three components:

(a) Fixed Cost Charge. This element is a ¢/kWh charge based on customer, transmission, distribution, and certain fixed power costs.

(b) Market Price Charge. This element is a ¢/kWh charge based on the adjusted (i.e., adjusted by customer class losses and revenue taxes) estimated market power price (Firm Mid-Columbia Index) for the day.

(c) Monthly Sales Credit. This component is a monthly ¢/kWh credit based on the estimated margin on secondary market power sales made by the Company.

(d) Hedge Cost Credit. This component is a ¢/kWh credit that removes the hedge costs that would otherwise be charged to customers who elect the tracked, rather than the hedged, option.

The tracked variable power cost charge (for block 1) for a month is subsequently adjusted through a true-up to reflect the actual tracked variable power costs for such month. The Market Prices (for block 2) for such month are subsequently adjusted through a true-up to reflect the sum of the actual tracked variable power costs plus certain non-tracked power costs for such month. The Monthly Sales Credit for a month is subsequently adjusted through a true up to reflect the actual Monthly Sales Credit for such month. (The true-up for a month also adjusts for any variance between the actual true-up charges or credits for such month and the true-up charges or credits projected for such month.) This true-up is made through a rider that provides a charge or credit (¢/kWh) applied in a subsequent month.

Q: Which costs are included in the Power Cost Tracker?

A: The power cost tracker addresses the primary drivers of volatility through two elements of the Company's variable power costs: secondary power purchase costs and natural gas fuel purchase costs. Non-tracked power costs are not trued-up for deviations between the costs reflected in rates and the actual costs. For example, non-tracked costs include costs of coal fuel and long term purchased power transactions.

Q: How will the Monthly Sales Credit for secondary sales margin be calculated?

A: The credit for a month will be projected in a two step process. First, the total margin will be calculated by estimating total monthly secondary sales revenue and subtracting the estimated variable power costs associated with producing those revenues. The associated variable power costs will be estimated based on a projected monthly merit order dispatch of the Company's power supply resources. It is assumed that the lowest cost resources are used to meet retail load and the highest cost resources are used to dispatch into the market. The difference between the secondary sales revenues and the associated variable power cost determines the monthly estimated secondary sales margin.

Q: Please summarize the rate components of the hedged rates?

A: Customers who take the hedged option will have their energy consumption billed at rates based on an Energy Charge. This is a ¢/kWh charge based on customer, transmission and distribution costs, as well as estimated hedging costs and other fixed and variable power costs. Certain of these variable power costs – secondary power purchase costs (net of secondary power sales revenues) and natural gas and oil fuel purchase costs – upon which hedges are based are revised annually for each one-year hedge period. The projected hedge costs are subsequently adjusted to reflect the actual cost of the hedges for the one-year hedge period.

Q. Does this conclude your testimony?

A. Yes, it does.

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