EXHIBIT NO. ______ (JAH-1T)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: JAMES A. HEIDELL

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DIRECT TESTIMONY OF JAMES A. HEIDELL ON BEHALF OF PUGET SOUND ENERGY, INC.

NOVEMBER 26, 2001

PUGET SOUND ENERGY, INC.

DIRECT TESTIMONY OF JAMES A. HEIDELL

I. INTRODUCTION

Q: Please state your name, occupation and business address.

A: My name is James A. Heidell and I am a Principal Consultant with PA Consulting Group. My business address is PA Consulting Group, Inc., 1881 Ninth Ave. Suite 302, Boulder, CO 80032.

Q: Please summarize your educational background and professional experience.

A: I have a BSE in Civil Engineering from Tufts University, a MS in Engineering Economics from Stanford University, and an MBA concentrating in Finance from the University of Washington. I am a Chartered Financial Analyst (CFA). I have twenty years of experience in the energy industry. I started as an engineer / consultant at Battelle Pacific Northwest Laboratories and subsequently at Synergic Resources Corporation. From 1990 to 2000 I worked at Puget Sound Energy in a number of positions including Manager of Pricing, Director of Federal and State Regulation, and Director of Financial Planning. In September 2000 I joined PA Consulting Group where I concentrate on the analysis of wholesale energy markets and economic analysis.

Q: Please summarize the scope of your testimony.

A: My testimony contains six components related to development of the electric rate proposal. (Mr. Amen addresses natural gas cost of service and rate design issues.) First, I briefly describe how the Company's cost-of-service and rate design is a reflection of PSE's corporate strategies. Second, I review the Company's cost-of-service analysis and highlight the changes made from the last general rate case to more accurately assign cost based upon cost causation. Third, I present the

Company's rate spread proposal to translate cost-of-service results into class revenue requirements. Fourth, I review the implementation of the Company's power cost tracker and hedged rates as introduced by Mr. William Gaines. Fifth, I present the Company's rate design and proposed tariffs. I conclude with a review of the proposed changes to the line extension policy, relocation policy, and miscellaneous charges.

Q: What Exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following Exhibits:

- Exhibit No. __ (JAH-2), Results Of The Cost-Of-Service Study
- Exhibit No. __ (JAH-3), Peak Credit Calculation
- Exhibit No. __ (JAH-4), Proposed Rate Spread
- Exhibit No. __ (JAH-5), Proposed Tariffs
- Exhibit No. __ (JAH-6), Impacts Of The Proposed Rate Changes
- Exhibit No. __ (JAH-7), Illustrative Calculation Of Proposed Hedged and Tracked Rates
- Exhibit No. __ (JAH-8), Graphical Summary Of The Power Cost Tracker

II. POLICY

Q: What is the relationship between Puget Power's strategies and your testimony?

A: Ms. Gullekson describes how PSE has created an environment of customer choice within the regime of regulated service for the vast majority of PSE's customers. In the context of providing customer choice it is important for customers to have both adequate and accurate information about the cost of the products they are purchasing. The pricing aspects associated with the implementation of PSE's strategies is one of the focuses of my testimony.

The Company is actively developing service options for its customers. Most of PSE's large load customers have elected to purchase their own power and purchase transmission at wholesale market rates. The remainder of PSE's electric customers are likely to be purchasing electricity at regulated prices for a number of years. However, customers can still make a number of choices within the regulated regime about the power product they purchase. These options include managing their energy consumption under the time-of-day program, an option to purchase green power, and an options to either have annual power cost stability, or to bear a portion of the market risk.

Q: What is your perspective on cross subsidization in Puget's rates?

A: Historically there has been cross subsidization in part due to concern about rate shock. In 1993 the Commission endorsed a policy of moving towards parity over three rate case cycles. At the time I doubt that many people anticipated that the second general rate case cycle would begin almost one decade later. It is my testimony that in the long-run cross subsidization is not beneficial since it provides incorrect price signals to customers and ultimately leads to non-economic decisions. In a monopoly regime customers have few alternatives to avoid situations where they are being charged more, so that another group of customers can pay less. However, as the industry continues to evolve there will inevitably be more alternatives and setting incorrect prices can lead to decisions that are not economic in the sense of reducing the overall cost of providing electric service. These decisions can also lead to an unnecessary increase in risk. As customers gain options and those who are paying subsidies opt out, those customers who remain are left holding the "bag" of fixed cost responsibility. While I endorse the benefits of gradualism to avoid rate shock. I think it is important that gradualism is not used as the basis for inaction.

It is also important to recognize that there are multiple sources of cross subsidization. First, intervenors inevitably endorse cost allocation methodologies that attribute more cost to customer classes that they do not represent. Second, the act of assigning a portion of the revenue target to each rate class (rate spread) typically incorporates a cross subsidy since parity is rarely argued except by the representatives of classes paying more than 100 percent of their cost assignment. Third, rate design within a class can result in intra-class cross subsidies. The WUTC has historically demonstrated a preference to recover fixed costs over volumetric charges resulting in low energy use customers being cross subsidized. Finally, there can be cross subsidies between old and new customers if new customers do not bear the full incremental cost of connecting to the electric gird.

The cost of service, rate spread and rate proposals that I have endorsed are designed to make a step in reducing cross subsidies and providing customers with sound price signals.

III. COST-OF-SERVICE

Q: Have you prepared a cost-of-service study to allocate the electric revenue requirement presented in Mr. Karzmar's testimony?

A: Yes, the results of the cost-of-service study are presented in Exhibit JAH-2. This study was prepared using the Excel model that the Company developed for the 1992 electric rate case and used in further filings in the 1990s.

Q: Have changes been made to COS classification or allocation procedures since the last Commission approved cost-of-service?

A: Yes. The last Commission approved electric cost-of-service was in 1993 resulting from the combined rate design case and general rate case in Docket Nos. UE-921262 and UE-920499. (The Company filed an unbundled cost-of-service filing under Docket Nos. UE-980181 and UE-980018, but there were no resulting

Commission cost-of-service directives.) The Company has retained many of the cost allocation procedures while incorporating some updates. The updates include: (1) changes to reflect the development of a new class of large load customers, (2) the separation of the transmission system as described in Docket No. UE-010010, (3) additional information available about the PSE distribution system, and (4) further analyses of cost causation.

Q: Why are you proposing to change cost-of-service classification and allocation methods?

A: The Company is responsible for presenting a reasonable, timely, and accurate cost-of-service with each general rate filing. Many of the cost-of-service approaches endorsed by the Commission in UE-920499, the rate design case, were the result of collaboration with rate case intervenors and customers that started in 1991. In the past decade there have been significant changes within the industry, the types of service provided to customers, as well as changes in the company's information systems. It is my testimony that these changes warrant modifying Commission directives established in the rate design case. A brief discussion of some of these changes follows.

One of the biggest changes in the last decade has been the evolution of the wholesale power market. The wholesale power market has evolved to include a number of active non-utility participants. These participants not only sell generation and risk management products to retail utilities, but also sell directly to some of PSE's largest customers. These market changes have resulted in a robust market with easily identifiable price signals. Another major change has been FERC's involvement in transmission pricing. Further, some of PSE's former large retail customers are now essentially wholesale customers. The Company has also invested additional effort in analyzing costs to better allocate transmission and distribution costs to customer classes. Finally, as PSE's customers demand more rate options there is increased pressure to "de-average" the cost of providing uniform service and to pay increased attention to allocating costs by specific services.

Q: What types of changes have been made to the cost of service procedures approved by the Commission in the last general rate case?

A: I have grouped the summary of cost classification and allocation procedures into six major categories: (1) introduction of a new customer class, (2) adjustment of billing determinants for demand and energy allocation, (3) energy and demand allocation factors associated with production costs, (4) non-generation related transmission cost allocation, (5) distribution cost allocation and (6) A&G / common cost allocations. Each of these categories have some components of the cost allocation procedures that have not change from the Rate Design Case, as well as components that have changed. The unchanged procedures are briefly summarized and the changes described in further detail.

<u>Development of New Customer Classes</u>

Q: Were any new rate classes created for the cost of service study?

A: Yes, a new rate class was created for Schedule 448 and 449 customers who purchase customer and distribution services from PSE at Commission established rates but purchase transmission at FERC rates and either secure their own power, or purchase power at market-based rates.

Schedule 448 and 449 customers are distinct from other classes since the purchase energy and part of their transmission services directly under FERC regulated rates power and transmission rates. Revenues received from the sale of FERC regulated power and bulk transmission services are credited to all customer classes except the Schedule 448-449 class and the associated costs are not directly allocated to the new class. This ensures that those other classes will pay only the net cost of providing those services. These customers are essentially wholesale customers and are treated comparably to other wholesale customers in the cost-of-service study with respect to power costs and bulk transmission costs (generally transmission over 230 KV). A forecast of revenues received from these customers for ancillary services and OASIS transmission sales are credited to the other customer classes.

<u>Adjustment of Billing Determinants</u>

Q: What is the role of billing determinants in preparation of the cost of service study?

A: Billing determinants are used to allocate power production and related costs. These costs account for approximately two-thirds of the costs allocated in the COS study. Power costs are classified as either energy, or demand. These two components are respectively allocated to each class based upon the class's contribution to total system energy use and coincident peak demand. Power production costs in this case are based upon energy requirements for the rate year (normalized by the production factor) assuming normal temperature and an average of historic hydro conditions. When the weather in the test year is either warmer, or colder than normal there is a mismatch between the pro forma energy and the determinants used to allocate production costs. There is also a mismatch when the customer mix differs significantly between the test and rate year. Temperature adjustments are used to proform test year residential sales to reflect normal weather and an adjustment was made to remove large power customers who will be securing their own power. The result is that the energy allocations are consistent with the normalized power costs for the rate year.

Q: Would you briefly describe how the weather sensitive energy adjustments were made?

A: The adjustments were made in a two step process. The first step was to determine which classes have temperature sensitive loads and the magnitude of the temperature adjustment between the test year and a normal temperature year. The Company assumes that the only weather sensitive class is the residential class and the HELM model was used to weather adjust the residential load shape developed from load research data. The second step was to adjust the weather sensitive differential for losses and normalize these adjustments to the difference between net GPI (power that is Generated, Purchased and Interchanged) and the temperature adjusted GPI.

Q: How were the monthly adjustments normalized and used to calculate the total class contribution to system sales?

A: Each class' weather adjustment was adjusted for losses and then normalized to equal the difference between power production's temperature adjusted and actual GPI. The normalized adjustments were added back to the pro forma class loads to develop the energy allocation factor.

<u>Production Cost Allocation</u>

Q: What costs are functionalized as production and how are they classified and allocated?

A: Fixed and variable production costs are classified as production. In addition, the costs of transmission used to integrate remote generation are allocated in the same manner as production costs. Transmission integration costs include both company-owned transmission and wheeling costs associated with integrating remote generation. The Colstrip transmission line and the Third AC transmission line are allocated in the same manner as production costs. Production costs and production related transmission costs are split into demand or energy according to the peak credit method and allocated to the class based upon class temperature and loss-adjusted energy use (the energy portion) and the class's contribution to the system's 200 peak hours (the demand portion).

Q: How was each class' contribution to the system's 200 peak hours calculated?

A: The company analyzed hourly load data from a statistical sample of customers. The analysis included data collected through the Company's Automated Meter Reading (AMR) system for 2001. The Company developed a statistical estimation of class loads for the second half of 2000 based upon the 2001 data and 1994 - 1995 load research data. This statistical estimation was necessary since load research data were not collected for the first half of the test year.

Q: Please briefly describe the peak credit classification method and how it has been calculated.

A: The peak credit calculation is used to classify production costs into energy and capacity components. Numerous approaches are used in the utility industry to classify production costs. The peak credit method was accepted by the Commission as a reasonable way to evaluate capacity costs on a combined hydro storage and thermal system. The peak credit estimates the proportion of production cost that is capacity related by dividing the cost of a proxy capacity resource by a proxy base load generation resource. This classification method is critical since it is applied to production and transmission cost and influences the allocation of approximately two thirds of the revenue requirement.

One adjustment was made to estimate the CT capacity cost for the purpose of the peak credit calculation. The levelized capacity costs of the CT were increased by seven percent to reflect spinning reserve standards for thermal generation in the Northwest. Adjustments for capacity costs for spinning reserves is a standard practice in determining the need for capacity. The result is the analysis of allocation of 16% of the production cost as demand related. This calculation is shown in Exhibit JAH-3.

Non-Generation Related Transmission Cost Allocation

Q: How have transmission costs been classified and allocated?

A: Transmission costs are separated into three categories. The first category is transmission that is used to integrate distant generation and to provide access to distant markets for the purpose of lowering power costs is allocated to the rate class' based upon the generation cost allocation factors. The remainder of the system is further separated into two categories based upon the FERC seven factor test. The application of the seven factor test was reviewed by the Commission in UE-010010. The two categories are referred to as bulk transmission and sub-transmission for the purpose of this cost of service study. (I have not adopted the FERC classification of "distribution" since I have reserved that term for the retail power distribution system that existed prior to the Company's reclassification filing with the Commission.) Both the bulk and sub-transmission systems are classified as demand and energy in accordance to the peak credit method and allocated to the customer classes based upon the 200 CP method. However, Schedule 448 and 449 customers are excluded from the 200 CP calculation for allocation of bulk transmission costs.

Q: Why does the Company exclude Schedule 448 and 449 demands from the 200 CP calculation for allocation of bulk transmission costs?

A: The Company does not allocate any transmission costs to these customers. Instead it credits the other classes of customers with revenues received from transmission sales to Schedule 448 and 449 customers. Under the Commission approved Schedules 448 and 449, customers take transmission service subject to the terms and conditions of the FERC Open Access Transmission Tariff (OATT).

The revenues received from the sale of transmission service are wheeling revenues, and are allocated in the manner of all wheeling revenues The customer pays the cost of this unbundled service directly, rather than having a portion of the cost allocated and bundled together with other costs to create a bundled rate. Instead of allocating the cost of transmission to the Schedule 448 and 449 customers, all other customers get their transmission costs reduced through the allocation of a revenue credit from the wheeling revenues produced by unbundled transmission sales to the Schedule 448 and 449 customers.

Q: Is the Company a proponent of using the peak credit and 200 CP for classifying and allocating the cost of the bulk transmission system?

A: No. However, the Company is willing to accept the Commission's decision in the Rate Design Case as long as the Commission adopts the Company's proposed cost allocation approach. In the long term it is recommended that the Commission adopt a methodology that is consistent with FERC's apparent direction -- allocating all transmission on demand and using either the 4 or 12 CP method. If the Commission does decide to move from the previously approved methodology, then I recommend moving towards the FERC approach.

<u>Distribution Cost Allocation</u>

Q: How were distribution plant costs allocated?

A: The Company directly allocated meter and line transformer costs using separate allocators derived from an analysis of installed meters and line transformers used by each class. The current equipment inventory was directly assigned to each class and the equipment was priced at current costs. The ratios of each class's contribution to the total cost were then applied to embedded costs to construct forward looking cost allocation. The cost of underground circuits, overhead circuits, and substations were assigned based upon allocation factors constructed from each class's contribution to the feeder's and substation's peak and the length of the distribution circuit. The allocation factors were constructed from monthly energy and load factors for the twelve month period ending in December 1999.

Q: Does this method differ from the approach approved by the Commission in Docket Nos. UE-920499 and UE-921262?

A: Yes. However, the primary difference is in the level of detail rather than a difference in philosophical approach. For example, in the last approved study distribution and substation costs were allocated at the system level based upon non-coincident peak demands. In this case, the Company took advantage of its databases to allocate these costs at a circuit and substation level based upon non-coincident peak demands. This is more equitable since classes that do not use a distribution feeder should not logically be assigned any cost of that feeder.

In general, direct assignment of costs is preferable to increase the accuracy of the cost causation study. In this study the Company moved towards a more direct cost assignment of line transformer costs. In the last case, the Company directly assigned meters to each class and the process was repeated in this study.

Q: Would you please describe how the transformer cost allocation factors were developed?

A: The Company used its customer database to associate each line transformer with the customers using the transformer. This resulted in allocating approximately 225,000 transformers to the different classes by type and size. Roughly 85% of the line transformers are used by a single class and thus were directly assigned. The remaining 15% were assigned to each class based upon the class's relative contribution to the transformer's peak load. The transformers were priced at current costs, including installation, to determine each class's contribution to embedded line transformer costs (FERC account 368).

Q: How were distribution line costs allocated?

A: The Company used its customer and distribution feeder databases to associate each of our customers with over 950 feeders in the company. NCP load factors were used for each customer class to determine each class's contribution to each feeder's peak load. Each class's contribution to peak was multiplied by the number of overhead / underground miles on the feeder. These allocators were then summed across all the feeders to develop the overhead and underground distribution line cost allocators. The overhead allocators were applied to FERC accounts 364 and 365 and the underground allocators were applied to FERC accounts 366 and 367. The method recognizes that the cost of the distribution feeder investment is a function of both load and line miles.

Q: Why should miles of distribution line be incorporated into the cost allocation?

A: The cost of building overhead or underground distribution lines is primarily a function of distance with cost adjustments for capacity. Cost is driven by the number of miles of trench excavated, miles of conductor required, number of poles installed, etc. There is an incremental cost for load, but it is relatively small since the Company uses only a few standard wire sizes for overhead and underground feeders and taps.

Q: Would you please describe how substation costs were allocated?

A: Yes, each customer class's contribution to the company's substation's peak was calculated using average hourly consumption of each class divided by NCP load factors. The resulting percentage was multiplied by the substation's costs to develop the substation cost allocations for FERC accounts 360-363.

Q: Were any other changes in distribution cost assignments made?

A: Yes, in the prior case, service lines were allocated on counts of customers who take service at secondary voltage. In the current cost of service all underground services are allocated to the residential class since non-residential secondary voltage customers own their own services. Overhead services are allocated by counts of secondary voltage overhead service customers by class.

General & Administrative Cost and Other Cost Allocation Factors

Q: How were G&A costs allocated?

A: These costs were allocated consistently with the methodology approved by the Commission in the Rate Design Case. The bulk of A&G costs are assigned on adjusted production, transmission, distribution, and customer costs. Property insurance was allocated on plant and pensions and employee insurance follow the allocation of salary and wages.

Q: What other direct cost allocators were used in the COS study?

A: The Company reviewed historical experience with late payment and assign the costs to each class. Other miscellaneous revenues associated with NSF checks and reconnects are allocated to each class based upon a historical analysis of revenues received.

Q: Were the cost allocators that were used in the COS study based on present revenues before deduction of the residential exchange credit shown as a separate item on the rate schedules for residential and small-farm service?

A: Yes. The rate schedules that show the residential exchange credit are Schedules 7, 307, 8, 10, 12, 29, 35, 56 , 59 and 194 (the "Residential Exchange Schedules"). The development of cost allocations in the COS study based on present revenues, before deduction of the residential exchange credit shown as a separate item on the Residential Exchange Schedules, is appropriate and fairly allocates the Company's cost is the COS study.

IV. RATE SPREAD

Q: Would you briefly describe rate spread and its relationship to cost-of-service and rate design?

A: Rate spread is the process of developing each class' share of the total revenue requirement. The process typically relies in significant part on the results of the cost-of-service study. Cost-of-service also provides guidance in structuring rates by identifying the customer, demand, and energy components of the revenue requirement. Rate spread is critical since this "divides the pie" between the customer classes. Although cost-of-service is the mechanism for identifying the allocation of costs to each customer class, the Commission has indicated that the results of cost-of-service should not be mechanically applied. Thus, rate spread is the process by which cost-of-service results are combined with policy considerations to develop class specific revenue requirements.

Q: What rate spread policy factors did the Company consider in developing its rate spread recommendation?

A: The Company considered two major factors: previously defined targets and customer bill impacts. In UE-920499 the Company indicated a target of moving customers half way to parity in the next general rate case. It is the Company's position that the target is still valid since removal of cross subsidies is an important factor in preparing for a changing electric utility industry. At the same time, the Company, like the Commission, rejected a mechanistic application of cost-of-service without consideration of rate impacts.

Q: What options did the Company consider in developing its rate spread recommendations?

A: The Company considered three options. The first option was to move each class half way to parity in accordance with testimony in the rate design case in Docket No. UE-920499. The second option was to move each class half way to parity if they are paying below parity with the remainder of the rate increase spread equally among the classes. This is consistent with the Commission's order in Docket No. UE-921262 as interpreted by Commission Staff. The third option was to move half way to parity with the constraint that no class's rate increase is greater than 150% of the average increase and no increase is less than 50% of the average increase.

The Company is recommending the third policy in the interest of balancing rate stability and equity. However, there are a few exceptions. First, customer classes that are on market base rates for all or part of their energy costs are not subject to the rate increase constraint. Second, smaller increases are justified in instances where competitive pressures would result in a net margin loss were the general policy not modified.

Q: Were the proposed class revenue requirements (rate spreads) based on present revenues before deduction of the residential exchange credit shown as a separate item on the Residential Exchange Schedules?

A: Yes. Development of the proposed class revenue requirements based on present revenues before deduction of the residential exchange credit shown as a separate item on the Residential Exchange Schedules is appropriate, fairly allocates the Company’s costs, and is consistent with the approach described above with respect to the COS study.

Q: Would you please summarize the parity ratios that resulted from the Company’s cost-of-service analysis and the proposed rate spread?

A: The results of the Company's study and the proposed allocation follow.

Customer Class	**Parity Ratio**	**Proposed Rate Increase**
Residential	94%	21%
General Service, < 51 kW	101%	17%

General Service, 51 - 350 kW	122%	9%
General Service, >350 kW	111%	11%
Primary Service	95%	20%
High Voltage – Retail	94%	19%
High Voltage – Wholesale	146%	9%
Lighting Service	82%	26%
Firm Resale	119%	9%
System Total / Average	100%	17%

Four rate classes pay less than parity: residential, primary service, retail high voltage, and lighting customers. The proposed rate spread is presented in Exhibit JAH-4.

Q: Are there any rate classes where the half way to parity approach was moderated?

A: Yes. The irrigation customers, interruptible schools, and lighting class had their rate increase limited to 1.5 times the average rate increase. In addition, the High Voltage wholesale class and Firm Resale were given the “minimum” increase of 8.5%. I recommend that moderation of rate increases makes sense in the situation where rates are sufficient to cover marginal costs but additional increases would drive customers to competitive alternatives. This is the case of irrigation rates in Kittitas County. Retention of the load at the proposed rate levels will provide a significant contribution to margin, and result in lower rates to other customers assuming that the alternative is reduced sales and no margin contribution. This is also the case with lighting services.

Q: How were cost-of-service customer, energy, and demand relationships translated into rate design?

A: The Company used the energy and demand relationships as a guide in setting demand rates and energy rates. In doing this calculation, COS demand revenues are typically less than revenues actually recovered from demand charges. This is a result of the demand allocations used in this COS and the fact that distribution costs are allocated on demand while a significant component of distribution cost has historically been recovered from kWh charges. In the last general rate case the Company reviewed the demand costs from the cost of service study and moved customers one-third of the way to full recovery of demand costs on demand charges. In this study the Company moved the further towards recovery demand costs on demand charges by moving one-half of the difference between costs and revenue recovery.

The basic charge was derived from COS in the manner accepted by the Commission in UE-920499. One enhancement was made; line transformer costs for residential and small general service customers are recovered in the basic charge.

V. POWER COST TRACKER AND HEDGE

Q: Has the Company developed a specific proposal to implement the power cost tracker and hedge programs described by Mr. William Gaines?

A: Yes. I will review the mechanics of the proposed tracker and hedge programs and the implications for rate design. The overall rationale for the program is addressed by Mr. William Gaines. The customer communication elements are addressed by Ms. Gullekson and the accounting treatment is addressed by Mr. Karzmar. In my testimony, I describe the implementation of the power cost tracker rates and the hedged rates. I have also provided a very general graphical summary of the power cost tracker rate concept in Exhibit JAH-8.

Q: Do all power customers have the choice of the tracked or hedged power cost option?

A: Virtually all power customers have the choice. The exceptions are lighting, interruptible schools, and irrigation customers who will be on the hedged rate and customers already on market or incremental cost rates.

Q: What is the relationship between the hedged and tracked power cost options and time of day rates?

A: The tracked and hedged power cost options are elected independently of whether the customer is on time-of-day or monthly rates.

<u>Power Cost Hedge</u>

Q: Please summarize the energy 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 cents per kilowatt hour charge based on customer, transmission and distribution costs, as well as projected hedging costs and other hedged and variable power costs. Adjustments for variations in 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 made annually for each one-year hedge period through Schedule 122.

Q: Please describe the calculations for Schedule 122.

A: Prior to the beginning of each calendar year commencing 2003, the adjustment for hedged rates will be calculated for such year. The following calculations are performed:

1. An estimate of the variable power costs (in cents per kilowatt hours of total estimated retail power load) for secondary power purchase costs (net of secondary power sales revenues) and natural gas and oil fuel purchase costs upon which hedges are based is developed for such upcoming year. The amount by which such estimate is greater or lesser than the amount of such variable power costs (in cents per kilowatt hour of retail power load included by the Commission for the test year) is the Variable Cost Adjustment (VCA) for such year and is added or subtracted as a cents per kilowatt hour adjustment through Schedule 122 for the up-coming year.

2. An estimate of the hedge costs (in cents per kilowatt hour of hedged load) is developed for the upcoming year. This estimate is compared to the amount of hedge costs (in cents per kilowatt hours of total estimated retail power load) included by the Commission for the test year (the Base Hedge Cost (BHC)). The amount by which such estimate is greater or lesser than the BHC is the Hedge Cost Adjustment (HCA) for such year and is added or subtracted as a cents per kilowatt hour adjustment through Schedule 122 for the up-coming year.

3. The amount by which the actual hedge costs (in cents per kilowatt hours of estimated hedged load for the current year) is greater or less than the sum of the HCA for such year plus the BHC is the Hedge Cost True-Up (HCT) and is added or subtracted through Schedule 122 for the up-coming year. For 2002, this item 3 equals 0.0 cents per kilowatt hour.

Q: Have you developed an illustrative calculation of rates under Schedule 122?

A: Yes. See Exhibit JAH-7, p. 8.

Power Cost Tracker

Q: Please summarize the energy 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 (either time-of-day rates or monthly rates, depending on whether the customer is on time-of-day rates) based upon the sum of three components that are combined into one rate recovered on a ¢ /kWh charge:

(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 ¢/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 ¢/kWh charge based on certain projected normalized power costs that are subject to the monthly 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.

Items (i), (ii) and (iii) are combined into a single rate.

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

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

The tracked variable power cost charge embedded in the bundled energy rate charged for block 1 for a month is adjusted through a true-up to reflect the actual tracked variable power costs for such month. The Market Price revenues (for block 2) for such month are adjusted through a true-up to reflect the sum of the actual tracked variable power costs plus a fixed allowance (¢/kWh) for non-tracked power costs for such month. (The true-up also adjusts for any variance between the actual true-up charges or credits billed and the true-up charges or credits projected to be billed.) This true-up is made through Schedule 123, which provides a charge or credit (¢/kWh) applied in the following month.

Q: Please describe how the Market Price Charge and total energy charge are established for the second block of tracked time-of-day energy rates.

A: By 6:00 PM of each day, the Company will establish the Market Price Charge (¢/kWh) for each period of the subsequent day for the second rate block (the 20% block). This Market Price Charge will be based upon the Company's estimate of the Dow Jones Firm Index Price for transactions at the Mid-Columbia during such subsequent day. This estimated Firm Index Price will be the average of the estimated heavy load hour (HLH) and light load hour (LLH) Firm Index Prices, weighted by the proportions of customer class load served during HLH and LLH in the prior day. The estimated Firm Index Price will be adjusted for customer class losses and revenue taxes. This adjusted estimated Firm Price Index will be used as discussed below to establish the Market Price Charge. (The Market Price Charge will not be adjusted for variations between the estimated and actual Firm Price Index.)

The total energy charge for each period of the day for the second rate block is the Fixed Charge plus the Market Price Charge for such period. The Mid-Day Market Price Charge equals the estimated adjusted Firm Index Price. The total charge for the Mid-Day second block is the sum of the Fixed Charge plus the Mid-Day Market Price Charge for such day. The Market Price Charge for the Morning period is set such that the total charge for the Morning period second block equals 112.75% of the total charge for the Mid-Day second block. The Market Price Charge for the Evening period equals the Market Price Charge for the Morning period. The Market Price Charge for the Economy period is set such that the average (load weighted by class consumption in the four periods during the prior day) of the total charges for the second block for the 4 periods equals the sum of the Fixed Charge plus the estimated adjusted Firm Index Price for the day. This calculation is shown on page 3 of Exhibit JAH-7.

However, on Sundays, NERC holidays, and any day for which the estimated Firm Price Index is less than 1.2¢/kWh, the Market Price for all periods of the day is equal to the estimated adjusted Firm Price Index for such day, and the total charge for the second block during all periods of such day is the sum of the Fixed Charge plus the estimated adjusted Firm Price Index for the day.

Q: Please describe how the Market Rate Charge is applied to time-of-day rate customers and monthly rate customers.

A: For time-of-day rate customers, the second block energy charge for each period of each day reflects such customer's metered energy consumption during such period and the Market Rate Charge for such period. For monthly rate customers, the second block energy charge for each month reflects such customer's metered energy consumption during such month and the average Market Price Charge for such month, weighted by the load shape of time-of-day rate customers in such customer's class during such month.

Q: Have you prepared an example of how the time-of-day tracked energy rate option works?

A: Yes. I have provided a detailed illustrative example in Exhibit JAH-7. For illustrative purposes, I will review how the energy rate will work for a residential customer on time-of-day rates.

(i) Each day the Company will use the Automated Meter Reading (AMR) system to read the customer's meter to determine how much energy is used in each of the four time periods of the day: Economy, Morning, Mid-Day, and Evening. An example of such consumption by day is shown on Page 2 of Exhibit JAH-7.

(ii) Eighty percent of energy use in each of the four time periods for the day will be billed at the first block time-of-day energy rate in Schedule 407. This component includes both the fixed and variable power costs bundled into a time-differentiated rate.

(iii) The remaining twenty percent of energy use in each of the four time periods for the day will be billed at the second block time-differentiated daily energy rate under Schedule 407 that is the sum of the Fixed Cost Charge and the Market Price Charge. This is also shown in Exhibit JAH-7 page 2.

(iv) The monthly bill will be adjusted (1) for the power cost tracker pursuant to Schedule 123 applied to all energy consumed, (2) the secondary sales credit applied to all energy consumed, and (3) a monthly credit applied to all energy consumed reflecting a discount equal to the Base Hedge Cost.

Q: How was the Fixed Charge Rate set forth for the second block of tracked time-of-day energy rates calculated?

A: The rate is based upon the results of the cost-of-service study presented in Exhibit JAH-2. The rate was calculated by subtracting variable power costs and customer costs from the total class revenue requirement expressed on a cost per kWH basis. The Schedule 31 and 26 rates had an additional adjustment to subtract out the revenue collected under the demand charge. The calculation is shown on Page 4 of Exhibit JAH-7.

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 cost associated with producing those revenues. This estimated variable power cost will be 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 estimates of variable power costs will be based upon estimates of costs in FERC accounts 501, 547, 555, and 456. The difference between the estimated secondary sales revenues and the associated estimated variable power costs (assuming the most expensive variable power cost resources were used) determines the monthly estimated secondary sales margin. The margin will then be divided by the estimated retail load to develop a credit per kWH. This credit will then be applied to the customer's consumption in the month. This calculation is illustrated on Page 6 in Exhibit JAH-7. In any month for which the credit would be negative, the credit will be set to zero. It should be recognized that any difference between the estimated margin and the actual margin on secondary sales is reflected in the monthly power cost tracker.

Q: How does the monthly power cost tracker work in conjunction with the tracked rate?

A: The objectives for the monthly tracker are to (1) ensure that the Company does not over-recover under-recover certain variable power costs as a result of the market rate component, (2) ensure that the Company recovers the actual tracked variable power costs, and (3) minimize any monthly over-collections or under-collections of the revenues necessary to recover the tracked variable power costs. These objectives are accomplished through a tracker that includes four components. The first three components relate to truing up balances associated with revenues and costs collected to date. The fourth component addresses a forecast for the next month. The objective of the forecast is to end the next month with a tracker balance as near to zero as practicable.

The first component of the monthly power cost tracker is a true-up of tracked variable power costs with the associated revenues collected. Near the end of each month the Company will estimate its tracked variable power costs. The total monthly tracked variable power cost will be divided by the ratio of monthly customer load on the tracked rate to the total monthly retail load to develop a cents/kWH tracked power cost. The Company will then calculate the associated revenues collected. These revenues are indirectly calculated since there is not a specific unbundled customer rate for tracked variable power costs. The associated revenue collected is established as follows:

(i) the revenues collected under the Market Price Rate plus

(ii) revenues collected in the first block that are attributed to the tracked variable power cost, less

(iii) the secondary power sales margin returned in the monthly credit, less

(iv) a credit to the Company for the non-tracked power costs with respect to the second block.

An example of this calculation is shown on Page 7 of Exhibit JAH-7.

The second component is a true-up of variances associated with the power cost tracker from the prior month. The true-up is necessary as a result of variances between the forecasted and actual sales volume for the month.

The third component is a true-up of estimates made to establish the tracker rate. The tracker rate for the month needs to be established prior to the start of the month. Therefore, there will be estimates of costs and revenues between the time that the balance is calculated and the end of the month. The variance in these estimates is calculated in the subsequent month and included in the tracker balance.

The fourth component is a forecast of tracked power costs, secondary sales margin credits, and Market Price Charge revenues for the subsequent month. The purpose of the forecast is to reduce the amount of variances between the revenues collected and the cost and hence reduce the level of costs or refunds that flow into the next month's balances of the monthly tracker.

Q: How will the Company determine the revenue collected in the first block that is attributed to the tracked variable power costs?

A: A rate per kWH for each customer class is determined by dividing the tracked power costs allocated to each class in the cost of service study divided by the pro forma kWH for such class for the test year. This calculation is made one time. It will be made after the test year tracked variable power costs and class allocation are determined in this case. Each month the unit rates will be multiplied by the respective first block volumes (80% of the tracked consumption).

Q: Why does the Company deduct a credit for non-tracked power costs with respect to the second block?

A: The purpose of charging the customer market price is to give the customer an up-to-date price signal. The Company's revenue requirement in this case includes both tracked and non-tracked power costs. A mechanism is needed for the Company to recover such costs. The mechanism for recovering the non-tracked power costs is to provide the Company with a credit equal to non-tracked power costs associated with each kilowatt hour sold. This ensures that only the tracked variable power costs in the second block will be trued-up, as compared with revenues collected under the Market Price Rate.

Q: How are the non-tracked power cost rates used in the monthly tracker calculated?

A: The Company will set these rates based upon the test year non-tracked power costs established by the Commission in this proceeding. These costs will be divided by the peak credit allocation factor used in the cost-of-service study in this proceeding.

Q: Have you prepared an illustrative sample calculation for the monthly tracked variable revenues and costs?

A: Yes. I have provided an example in Exhibit JAH-7 page 4.

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

A: The secondary power purchase costs (including day of and day ahead purchase costs) in FERC Account 555 are tracked variable power costs. In addition, all costs in FERC Account 547 are tracked variable power costs. The tracked variable power costs are estimated to be $75 million in the test year. This calculation is shown in Exhibit JAH-7.

Q: How will the balances in the monthly tracker account be returned/charged to customers?

A: Prior to the end of the month the Company will estimate the monthly tracker amount, as described in Schedule 123, and the adjustment associated with the forecast of tracked power costs, secondary sales margin credits, and Market Price Charge revenues for the subsequent month. This amount will be divided by the forecast of tracked rate customer loads for the following month, as described in Schedule 123.

Q: Why are true-ups from prior months necessary in the Company's proposal?

A: The Company will be setting the Schedule 123 adjustment for the following month prior to the end of the current month, so that the tracker adjustments are made based on volumes relatively comparable to the volumes of the period being trued up. In this way customers who use more electricity in a particular season will be more likely to be assigned a fairer pro rata share of the balances in the account. One consequence is that it will take a few weeks subsequent to the end of the month to know the actual account balance. The second reason for the adjustment is that there is bound to be forecast error associated with the estimated sales volumes for the following month. The volume variance will not be known until after the end of the month that is being used to collect the balance.

VI. RATE DESIGN

Q: Has the Company prepared new tariffs based upon the rate spread proposal?

A: Yes, the tariffs is presented in Exhibit JAH-5. In this section of my testimony I will describe the new rate initiatives and the principles used to adjust existing rates.

Q: Has the Company included a revised index of rate schedules with this filing?

A: No. In order to avoid substitutions during the period of time that the tariff sheets included in this filing will be suspended. The Company plans to file a revised index at the time new schedules go into effect.

Q. Has the Company introduced new tariffs as a result of the power cost hedge and tracker options?

A. Yes, currently the Company has separate rate schedules for monthly and time of day metered customers. For example, there is Schedule 7 for monthly metered rates and 407 for time of day rates. Schedules 7, 24, 25, 26, and 31, the "monthly schedules", already have companion schedules for time of day rates. The Company is introducing two new companion schedules for the original monthly schedules in order to implement the tracker and hedged power cost options. The retail energy schedules numbered below 50 (Schedules 7, 24…) reflect monthly metering and the hedged power cost option. Monthly metered customers who elect the tracked power cost option have schedule numbers with a prefix of 5 (i.e. 507, 524 …). The time of day billed customers who elect the tracked power cost option will have a schedule prefix of 4 (i.e. 407, 424…). Finally, those time of day billed customers who elect the hedged option will have a schedule prefix of 3 (i.e. 307, 324, ..).The tariff numbering system is schematically shown in the following illustration.

	Monthly	Time-of-Day	Rider
Tracked	5xx	4xx	123
Hedged	XX	3xx	122

XX is the number of the current monthly rate schedules (07, 24, 25, 26, 29, 31, 35, and 43), which will be hedged rate schedules.

Q: Please summarize the Company's electric rate design initiatives.

A: The Company proposes to expand PEM to all Automated Meter Reading (AMR) enabled customers and to make time-of-day rate structures a permanent feature. The time-of-day rate structure provides customers with cost based price signals and allows customers to manage their energy use. In addition, as previously discussed, customers will be offered a choice between a hedged price power portfolio or an option where part of their power costs are tied to market based rates. Finally, customers will also have an option to support green power.

The Company is also proposing a number of refinements in the rate design to provide correct price signals and appropriately charge customers for the services they are using rather than being cross subsidized by other customers. These refinements include resetting and establishing new demand charges, resetting marginal price signals designed almost a decade ago updating miscellaneous charges, and redesign of the electric line extension policy.

Q: Please describe how the customer choice program will work?

A: First, all electric service customers on PSE's AMR network will have the ability to manage their energy use under the time-of-day rate program. Second, as previously described, customers can either elect to pay a hedged rate for all their power, or can choose to have 20% of their power cost tied to the daily market price. Customers, on an annual basis can choose to pay a hedged rate which will be the sum of the rates they are paying on their base schedule and Rider 122. If the customer does not elect the hedged rate, they will have a market based component to their power costs which will be reflected through power cost adjustments in Rider 123. Customers who sign up for new electric service after the election date will still have the choice of making the election of either the hedged, or variable power cost portfolio.

Third, customers can participate in the green rate program. Customers can elect to purchase green power and support the development of new green resources and habitat restoration through Rider 135 (residential) and Rider 136 (non-residential) where they elect to make a monthly payment.

Q: Why are refinements to current rate structures needed to send efficient price signals?

A: The Company's last cost of service and general rate design review was done almost a decade ago. The Company reviewed its new cost of service study with respect to identifying customer costs, demand and energy costs, and seasonal marginal costs and determined that refinements are appropriate. The refinements are appropriate due to relationships that have become distorted as a result of equal percentage and equal cent rate increases over the PRAM era and rate stability period. In addition some changes are appropriate as a result of gradual changes make in UE-921262 as a result of adopting the principle of gradualism. Finally, the study of marginal power costs has been updated.

Residential Rates

Q: What was the Company's general approach to the residential rate design?

A: The Company's approach was to first examine how the price should be set on a theoretical basis and then compare the theoretical approach with the alternative of maintaining the current structure through an equal percentage rate increase. The first step was to define the basic charge. The pro forma basic charge revenues were then subtracted from the proposed residential revenue requirement and an average volumetric rate was calculated based upon the pro forma billing determinants. This average rate was then shaped by an examination of seasonal cost differentials in power costs, short-run intra-day power cost differentials, and a review of long-run marginal costs.

Q: What conclusions did you draw about the seasonal differential?

A: The current seasonal differentials were reviewed and it is the Company's recommendation that the differential be eliminated. In Docket Nos. UE-920499 and UE-921262 the issues of seasonal differentials was reviewed and a ten percent seasonal differential was applied to the residential incremental block based upon winter costs being higher than summer costs. Almost a decade later the power markets have reversed and the Company's Aurora study indicates that market on-peak and off-peak power costs are higher in the summer than in the winter. Consequentially the Company is proposing to end the summer winter seasonal differential. A higher summer rate is not proposed In deference to the principle of gradualism. At the same time, it is considered important to at least eliminate the seasonal differential to start educating customers about current markets where power is no longer "cheap" in the summer.

Q: What are your recommendations with regards to intra-day price differentials?

A: Recently, the Company developed a number of analyses of daily price differentials in the process of developing the experimental TOU rates as part of the PEM program. The parties came to an agreement that balanced multiple factors including actual differentials, price signaling, and customer impacts. At this time, the Company does not feel it is necessary to revisit the agreed upon differentials.

Q: What are your recommendations with respect to design of the two-block structure for customers not on time-of-use rates?

A: The two block rate design for Schedule 7 was adopted by the Commission in Docket Nos. UE-920499 and UE-921262. The two-block design represented a balance of arguments presented by different parties to the last general rate case. First, the incremental block was designed to provide customers with a marginal cost price signal to encourage efficient energy use. Second, the lower priced first block of 600 kWh was appropriate for equally sharing the benefits of the Company's low cost production resources. The Company is currently in a situation where the average of its marginal costs over the next twelve years are actually below the current incremental block rate. From an economic efficiency perspective, this means that the block structure should be flattened. If the incremental block is both above marginal cost and higher than the first block, then customers are not being sent a correct price signal and the larger use customers are subsidizing the lower electric use customers.

An alternative cost-based justification for a higher incremental block is that the winter system peak is driven in part by residential heating loads, and thus residential customers that use space heat should pay the majority of these costs The peak-credit method has been adopted by the Commission as the approach for identifying capacity cost. Based upon a "peak credit" CT costing $57.38 / year and the winter rate in effect for half the year, a 1.11 cent rate differential for the incremental block is proposed in the new rate design.

The incremental block differential is also reflected in the time-of-day rate design. The time of day rates are based around the first block energy charges and the High Use Surcharge of 1.11 cents is charged to all monthly consumption in excess of 600 kWH.

Q: Is the Company proposing to change the residential basic charge?

A: The Company is proposing to increase the basic charge from $5.44 to $9.00 for single phase customers and from $13.44 to $22.20 for three phase customers. These proposed charges reflect the basic customer method of calculating the basic charge adopted in UE-920499 with a modification that line transformers were moved into the basic charge. Line transformers are installed for specific customers in the same manner as meters and services.

Q: Is the Company proposing any change to Schedule 194?

A: Schedule 194 has been updated to include the entire Residential and Farm Energy Exchange Credit. Schedule 94 will be cancelled.

Q: Will the time-of-day rate continue to be an experimental rate?

A: No. The Company has proposed to make the rate permanent and all customers with appropriate metering equipment will be on the time-of-day rate. Schedule 105, Time of Day Pricing Adjustment has been withdrawn since the program is no longer experimental and the load shifting associated with PEM is reflected in the power costs.

Q: Have you estimated the impacts of the proposed rate changes?

A: Yes. The impacts are shown in Exhibit JAH-6.

General Service Secondary Voltage Rates

Q: What rate design changes are being proposed for General Service Rates for customers with demands below 50 kW?

A: The Company is proposing to eliminate the seasonal differential. As I previously noted, average summer power costs are now higher than winter power costs so charging less in the summer is not appropriate.

Q: What rate design changes are being proposed for General Service rates for customers with demands between 50 and 350 kW?

A: The Company has eliminated the seasonal energy differential but has retained the seasonal demand differential. In addition the time-of-day rates are made the permanent default rate.

Q: What changes are being proposed for General Service rates for customers with demands in excess of 350 kW?

A: Three changes are being proposed. First, the status of 326 is being changed from experimental to the permanent default rate. The second change is that the seasonal energy differential has been eliminated. The third change is to introduce a new rate block for monthly consumption over 3,650,000 kWH. This block will be priced at market rate adjusted upward by 6% for transmission and distribution losses.

Q: How will the rate be set for the incremental block of Schedules 26 and 326?

A: Mr. William Gaines addresses development of this rate based on an average of up to three bids. That average of those three bids will be adjusted for losses and revenue tax and be used as the incremental block rate. Parallel modifications have been proposed for the Company's primary rate schedule 31 and high voltage rate schedules 46 and 49.

Q: How was the demand charge set for the incremental block?

A: The demand charge was based upon the fully loaded T&D costs in the cost of service study recovered on a flat monthly charge per kW.

Q: Have you examined the rate impacts of this proposal?

A: Yes, there are no customers who will be impacted since no customers on this schedule have loads that are sufficiently high to be in the incremental block.

Q: What are you proposing for irrigation customers?

A: In Docket Nos. UE-920433, UE-920499, and UE-921262 the Commission directed the Company to eliminate the irrigation rates, Schedules 29 and 31 if the Bonneville Power Administration eliminates the irrigation credit (Schedule 97). Bonneville eliminated the credit approximately five years ago. However, the Company continued the seasonal credit through the summer of 2001. The Company does not recommend eliminating the irrigation rate and moving the customers to general service schedules. There are two problems with moving the irrigation customers to general service rates. First, the customers would experience rate shock and with an average rate increase of approximately 60% and 75% of the customers experiencing rate increases of over 45%. Second, a number of these customers have competitive alternatives in the form of taking service from PUDs in Kittitas County. As long as the rates are set above variable costs, the remaining PSE customers are better off by retaining the customers.

Q: How do the current irrigation rates compare with Kittitas County PUD rates?

A: I compared PSE's current Schedule 29 rate without Schedule 97 with Kittitas' new Schedule C-00. I determined that the Kittitas County's new rate will be, on average, approximately 30% higher than PSE's current irrigation rate. However, under current rates over 25% of the PSE irrigation customers will have energy bills more than 50% higher than the new Kittitas rate.

Q: What is the Company's rate recommendation with regards to irrigation customers on Schedule 29?

A: The Company's recommends an increase of no more than 1.5 times the overall rate that the customers are now paying. This translates into approximately a 30% rate increase. As I previously noted, my calculations show that moving these customers to general service rates would result in rate shock and even rate increases in the range of 30% may lead to a loss of customers who are making a positive contribution to earnings.

<u>Primary Service Rates</u>

Q: Would you please summarize the Company's proposal with respect to Primary Voltage rates?

A: The Company is proposing two changes. First, the experimental rate Schedule 331 will be made the permanent default rate for primary service customers. Second, an incremental block has been added. It will work and be applied in the same manner I described for Schedule 26. The incremental block will be priced in the manner described by Mr. William A. Gaines.

Q: Will any existing customers be affected by this rate?

A: No.

<u>High Voltage Rates</u>

Q: Would you please summarize the Company's proposal with respect to High Voltage rates?

A: The Company is proposing three changes. The first change is to eliminate the annual minimum charge provision in Schedule 46. This provision is viewed as redundant in conjunction with the existing minimum monthly demand requirement of 4,400 kVA. The second is to put all customers in this class on time-of-day rates. The third change is to create an incremental block market rate that will work and be applied in the manner described by Mr. William A. Gaines.

Q: Please described how the incremental block will work and how it will be applied?

A: It will work and be applied in the same manner I described for Schedule 26.

Q: Please summarize the time-of-day pricing proposal - for Schedule 46 and 49 customers?

A: The Company has developed Schedules 346 and 349. The time block differentials mirror the block differentials developed for the other TOU schedules.

Interruptible Rates and Standby Rates

Q: Would you please review the status of the Company's interruptible rates?

A: The Company currently has six schedules on file with credits for interruption of electric service. The most recent schedule, Schedule 93, was introduced in June, 2001. Four of the interruptible schedules are closed to new customers. The closed schedules are: Schedule 43 (primary all-electric schools), Schedule 36 (interruptible credit for Schedule 26 customers), Schedule 38 (interruptible credit for Schedule 31 customers) and Schedule 39 (interruptible credit for high voltage customers). Schedule 46, an interruptible schedule for high voltage customers has one customer. There are currently 12 customers on Schedule 93, one customer on Schedule 38 and no customers on Schedules 36 and 39.

Q: What is the Company's proposal with regards to its interruptible rates program?

A: The Company is proposing to extend Schedule 93 beyond its current October 31, 2002 termination. However, based upon experience in the winter of 2001 and 2002 the terms may be modified. It is important to maintain flexibility with regards to offer customers economic choices with regards to the delivery terms of their power. The Company has not refiled Schedules 36, 38, and 39 since the tariffs are closed and no customers are on those Schedules. Finally the terms and conditions for interruption under Schedules 43 and 46 remain unchanged.

Q: What is the Company's proposal with regards to the closed interruptible rate schedules 36, 38, and 39?

A: The last customer on these rates will have their commitment terminate on October 1, 2002. As a result all three of these rates have not been refiled.

<u>Standby Rates</u>

Q: Has PSE's developed any standby rate initiatives?

A: Currently the Company does not have standby distribution rates for any class of customers. The Company has Back-Up Distribution Service Schedules 458 and 459 for Schedules 448 and 449 customers respectively. The rates were filed as part of the Stipulation of Settlement in Section 16 in the Commission's Eleventh Supplemental Order in Docket Nos. UE-001952 and UE-001959. At the time of the filing the Company indicated "the rates for Back-Up Distribution Service are subject to change in PSE's next general rate case, at which time the Company may pursue rate methodologies different than the principles set forth in Section 16 of the Stipulation of Settlement."

The Company is proposing to eliminate the Reliability Adjustment Factor in Schedules 458 and 459. The Company’s experience to date suggests that these customers with self-generation are not providing benefits to the system.

At this point the Company has not proposed a Back-Up Distribution Service rate. A rate is likely to be proposed at a later date once the cost-of-service study in this proceeding has been reviewed by the Commission.

VII. LINE EXTENSIONS, CONVERSIONS, AND MISCELLANEOUS CHARGES

Q: Why is the Company filing a new electric line extension policy?

A: The Company's goals in developing the new electric line extension policy were to (1) treat electric and natural gas line extensions consistently, (2) develop a policy that is easy to explain to customers, (3) ensure that new customers are paying their fair share of the hookup costs, and (4) to create a policy that is relatively simple to administer. The existing line extension policy predates the merger of Washington Natural Gas and Puget Power and has outdated construction costs resulting in upward pressure on rates and cross subsidization of new customers by existing customers.

Q: Would you please highlight the changes associated with the new line extension policy?

A: A number of conceptual changes are incorporated into the new policy. First, the Company has shifted from a two times revenue allowance for new construction to the contribution to margin approach currently used for natural gas line extensions. Second, the mechanism for granting the construction cost credit to non-residential customers has been changed to remove incentives for over-stating load. Third, the policy has been modified to reflect new construction costs in order to reduce cost shifting. Finally, the cost elements have been standardized where practical to enable simple cost calculations for the majority of customers requesting line extensions. The standardized costs have been updated to reflect costs in the test year.

Q: Have you estimated the financial customer impacts associated with the proposed tariff?

A: Yes, the impacts are shown in Exhibit JAH-6.

Q: Would you please describe the proposed changes to the Company's policy with regards to over-head to underground conversions?

A: As described by Ms. McLain, the Company recently completed an evaluation of its line conversion policy and has determined that the historical credit given to the conversion cost is no longer cost based. Based upon the Company study of conversions it was determined that conversion from overhead to underground lines does not reduce costs. Consequentially the conversion credit was eliminated except for the instances where the Company would otherwise have to relocate the overhead distribution system. In the later case, a 24% discount to the conversion costs will be applied.

Q: Why is the Company proposing to change miscellaneous charges?

A: Over the past four years the Company has made two tariff filings to adjust miscellaneous charges so that customers pay the appropriate charge for special services. This third set of changes is part of the Company's continued effort to reduce cross subsidies and send proper price signals.

Q: Please describe the specific changes requested by the Company.

A: The Company is proposing four changes to the electric miscellaneous charges. First, the NSF check charge will be increased from $10 to $12. Second, the electric disconnection visit charge will be increased from $9.00 to $15.00. Third, the charge for initiation of electric only service will increase from $5.50 to $10.00 while the initiation charge for combined electric and gas service will increase from $7.00 to $12.50. Finally, the charge for reconnection of electric service will increase from $20.00 to $32.00 for day-time reconnects. Evening reconnects will decrease from $40.00 to $32.00.

Q: Does this conclude your testimony?

A: Yes.

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