EXHIBIT NO. ___(RJA-1T)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: RONALD J. AMEN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-06____ Docket No. UG-06____

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF RONALD J. AMEN ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 15, 2006

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ronald J. Amen. My business address is 1201 Third Avenue, Suite 3320, Seattle, WA 98101.

Q. By whom are you employed and in what capacity?

A. I am a Director with Navigant Consulting, Inc. ("NCI") and a member of the Litigation, Regulatory and Markets Practice Area of the Firm. NCI is a leading nationwide provider of consulting services to electric and gas utilities and other energy-related and network businesses.

Q. Please describe NCI's business activities.

A. NCI is a global management consulting firm that provides strategic, financial, management, and expert services to energy-based, network and other regulated industries. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas and electric industries. Included in NCI's relevant experience are the areas of utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at transmission and distribution, gas pipeline and other energy-related companies, and through a wide variety of client assignments. NCI has assisted numerous utility companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over twenty-seven (27) years of experience in the utility industry, the last eight (8) years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management and energy marketers in matters pertaining to costing and pricing, regulatory planning and policy development, strategic business planning, organizational restructuring, new business development, and load research studies. Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in Exhibit No. ___(RJA-2).

Q. Have you testified previously before the Washington Utilities and Transportation Commission ("the Commission")?

A. Yes. I have testified in Docket Nos. UG-931405 (General Rate Case of Washington Natural Gas Company ("WNG")), UG-940814/UG-940034 (Cost of Service and Rate Design Proceeding of WNG), UG-941246/UG-950264 (WNG

Line Extension Policy), UG-950278 (General Rate Case of WNG), UE-960195 (Merger of Washington Energy Company and Puget Sound Power and Light Company), UG-960520 (WNG Propane Service), and UG-011571 (General Rate Case of Puget Sound Energy). I have also previously appeared before the Commission on numerous occasions regarding various regulatory, customer contract and tariff matters.

II. PURPOSE OF TESTIMONY

Q. For what purpose has NCI been retained by Puget Sound Energy, Inc. ("PSE" or "the Company")?

A. NCI has been retained by PSE as a consultant in the area of utility costing and rate design and related regulatory matters. Specifically, PSE has requested that we assist the Company in conducting a cost of service study to determine the embedded costs of serving its natural gas retail customers, in addition to the development of a ratemaking solution to address the significant negative impact that the uncontrollable factors of declining gas use per customer and weather have on PSE's financial performance.

Q. What is the purpose of your testimony in this proceeding?

A. First, I will describe the NCI Cost of Service Model used by PSE for the Company's electric and gas cost of service studies.

Second, I will discuss various principles of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in the Company's gas cost of service study.

Third, I will discuss revenue allocation and rate design principles, and the appropriate guidelines for use in evaluating class revenue levels and rate structures.

Finally, I will present and explain PSE's proposal to implement a natural gas revenue decoupling mechanism, which the Company is proposing to call its Gas Revenue Normalization Adjustment ("GRNA"), to better ensure that the Company recovers the overall amount of revenues from its gas customers that the Commission approves in rate cases even when the amount of gas used by individual customers subsequently declines or when the weather is warmer than normal. This mechanism will adjust base rates on an annual basis for the margin impact of fluctuations in the Company's actual gas volumes caused by variations from "normal" weather and for reductions in the Company's gas volumes caused primarily by the energy efficiency efforts of its customers. I will discuss the reasons why PSE has decided to propose this ratemaking mechanism at this time, the industry-wide conditions that support the implementation of a decoupling concept, the conceptual underpinnings and computational details of the Company's proposal, and the benefits to gas customers and to PSE that are anticipated to flow from adoption of the GRNA.

III. NCI'S COST OF SERVICE MODEL

Q. Please discuss the Company's selection of the NCI Cost of Service Model ("NCI Model") for purposes of conducting the cost of service studies filed in this proceeding.

A. In the instant general rate case, PSE has selected the NCI Model for purposes of conducting both the gas and electric cost of service studies. An earlier version of the NCI Model was used for the Company's gas cost of service study filed in its 2001 general rate case, Docket Nos. UE-011570 et al. A Company-developed cost of service model was employed in the 2001 general rate case for the electric cost study. The Company's electric cost of service model was developed in the 1990's and has been in use since that time. In the Company's 2004 general rate case, Docket Nos. UG-040640 et al., the Company-developed model was used for both the gas and electric cost studies. However, because the model was originally designed for the evaluation of electric utility service costs, it was more recently judged by the Company to be not well suited for application to the analysis of retail natural gas distribution and supply costs.

In an effort to standardize the cost of service model used, the current NCI Model was evaluated by the Company and selected for application to both the electric and gas cost of service studies in the present general rate case. As in the 2001 general rate case where the NCI Model was employed, NCI and the Company will work with parties needing access to the model by providing access under terms of a temporary license, along with instructional materials on the operation of the model. An informational brochure describing the NCI Model's components, basic parameters, reporting capabilities, and key features accompanies this testimony as Exhibit No. ___(RJA-3).

Q. Has the NCI Model been employed elsewhere for both gas and electric utility cost of service applications?

A. Yes. The NCI Model has been used in recent times at the following utilities: Peoples Energy (IL); NW Natural (WA); Terasen Gas (British Columbia); City of Tacoma, Washington; Intermountain Gas (ID); Long Island Power Authority (NY); Oklahoma Natural Gas (OK); Arkansas Oklahoma Gas (AR, OK); PG Energy (PA); Chesapeake Utilities (DE); City of Richmond, Virginia; City of Fayetteville, Arkansas; City of Vero Beach, Florida; Great Lakes Power (Ontario); and CLP Power (Hong Kong).

IV. FACTORS INFLUENCING THE COST ALLOCATION FRAMEWORK FOR A NATURAL GAS UTILITY SUCH AS PSE

Q. Please discuss the factors that you believe can influence the overall cost allocation framework utilized by a natural gas Local Distribution Company ("LDC") such as PSE.

A. The overall framework within which an LDC performs a cost of service study, that is, the three standard steps or phases followed by a utility when performing a cost study – cost functionalization, cost classification and cost allocation, can be influenced by various factors. These factors can include: (1) the physical configuration of the LDC's gas system; (2) the availability of data within the LDC; and (3) the state regulatory policies and requirements applicable to the LDC.

The physical configuration of the transmission and distribution system provides certain considerations. For example, is the distribution system a centralized grid/single city-gate[1] or a dispersed/multiple city-gate configuration? Does the LDC have an integrated transmission and distribution system or a distribution-only operation? Does the system operate under a multiple-pressure based or a single-pressure based configuration?

The structure of the LDC's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region and the types of load data available.

State regulatory policies and requirements refer to the particular approaches historically used to establish utility rates in the state. Specific methodological preferences or guidelines for performing cost studies or designing rates, which have been previously established by the state regulatory agency, can influence the

[1] A "city-gate" is a point at which an LDC's distribution system interconnects with a transmission pipeline that supplies the natural gas that is distributed by the LDC to its end-use customers.

particular cost allocation method utilized by the LDC.

Q. How do these factors relate to the specific circumstances applicable to PSE?

A. The physical configuration of the Company's gas system is a dispersed/multiple city-gate, integrated transmission/distribution and multi pressure-based system. The Company has detailed plant accounting records for many of its distribution-related facilities. Additionally, detailed gas supply expense data is available by specific supply and capacity resource. Finally, over the years, this Commission has expressed a preference for LDCs to utilize a costing methodology that allocates some fixed costs on the basis of annual use (or throughput) in order to reflect the fact that a gas distribution system is built to deliver gas year round.

Q. Why are these considerations relevant to conducting the Company's cost of service study?

A. It is important to understand these considerations because they influence the overall context within which the Company's cost studies were conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the Company's gas system design and operations and understanding the regulatory environment in the State of Washington as it pertains to cost of service studies and gas ratemaking issues.

V. PRINCIPLES OF COST ALLOCATION

Q. Please state the purpose of a cost of service study.

A. A cost of service study is an analysis of costs which attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of these studies can be utilized to determine the relative cost of service for each class and to help determine the individual class revenue requirements.

Q. What are the guiding principles that should be followed when performing a cost of service study?

A. The concept of *cost causation* is the fundamental and underlying philosophy applicable to all cost studies for purposes of allocating costs to customer groups. Cost causation addresses the question: "Which customer or group of customers causes the utility to incur particular types of costs?" To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

The essential element in the selection and development of a reasonable cost of service study allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the utility in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service. Ms. Janet Phelps' testimony, Exhibit No. ___(JKP-1T), provides information regarding the specific load and service characteristics of PSE's customers.

Q. Why are the relationships between customer requirements, load profiles and usage characteristics significant to cost causation?

A. The distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with services, meters, regulators and customer billing and accounting expenses.

Demand or *capacity* related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains, or more localized distribution facilities which are designed to satisfy individual customer maximum demands. Gas supply contracts also can have a capacity related component of cost relative to the company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the utility for its sales service customers.

Q. What are the steps to performing cost of service studies?

A. The three broad steps used to perform cost of service studies are: (1) functionalization; (2) classification; and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include: production, storage, transmission and distribution.

Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer; (2) demand or capacity; and (3) commodity.

The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated on customer, demand, and commodity or revenue allocation factors.

Q. How does the cost analyst establish the cost and utility service relationships?

A. To establish these relationships, the cost analyst must analyze a company's gas system design and operations, its accounting records and its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain the term "direct assignment."

A. The term "direct assignment" relates to a specific identification of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods.

Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, "common" allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform a cost of service study.

A. As stated above, in order to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with and supportive of rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

Q. Please describe the key issues related to the allocation of demand-related costs within a cost of service study.

A. A complex part of the allocation process is the allocation of demand-related costs. Several methodologies have been used by gas utilities to develop allocation factors for the demand components of costs. In fact, it is not unusual for more than one demand cost allocation methodology to be used in a cost of service study. Despite the use of different methods to allocate demand costs, it is fair to say that three basic methodologies form the foundation for the allocation process. These three methodologies are Peak Demand Allocations, Average and Excess Demand Allocations and Non-Coincident Demand Allocations. Each of these demand allocation methodologies is discussed below.

Q. What is the Peak Demand Allocation methodology?

A. The concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load or peak loads of the company. Under this methodology, demand related costs are allocated to each customer class or group in proportion to the demand coincident with the system peak or peaks of that class or group. The Peak Demand Allocation process might focus on a single peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of several cold days or the expected contribution to the system peak on a design day.

Q. What is the Average and Excess Demand Allocation methodology?

A. The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand and is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand (i.e., total class non-coincident demand minus average demand).

A simplified version of this methodology is the Peak and Average methodology. This cost methodology often gives equivalent weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's capacity costs on a commodity-related basis.

Q. What is the Non-Coincident Demand Allocation methodology?

A. The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, are designed to serve local peaks, which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each group's or rate class's maximum demand, irrespective of the time of the system peak.

VI. IDENTIFYING THE COSTS OF TRANSPORTATION SERVICE

Q. Please describe the preferences the Commission stated for deriving the costs of transportation service in the Company's gas rate restructuring Order in Docket No. UG-940814, and how the Company accommodated those preferences in its current gas cost of service study?

A. The Commission expressed a preference for conducting a cost of service study with separate classes of service for sales and transportation service customers. In its Order, the Commission stated that, "it is essential that the cost study identify costs of gas for sales customers and the fixed and variable costs that are unique to transportation service." (Docket No. UG-940814, Fifth Supplemental Order, mimeo at 16). Also in that Order, in commenting on the Company's analysis of the administrative costs of transportation service, the Commission indicated that "complete and accurate information on the topic, including, if needed, fact-based estimates of reasonable costs to perform functions must be provided in future proceedings." (*Id.* at 24). The Company's cost of service study reflects both of these requirements in deriving the costs of transportation service.

The Company established separate classes in its cost of service study for the two customer groups that receive transportation service – Rate Schedule 57 and Rate Schedules 99/199/299 (Special Contracts). Secondly, the cost study reflects the results of a detailed analysis that identified the costs of the various administrative activities required to support transportation service. These administrative costs include activities such as customer gas nominations, transport billing, gas measurement support, customer assistance, and gas balancing provided by the Company.

VII. THE METHODOLOGICAL AND CONCEPTUAL BASIS USED IN THE COMPANY'S COST OF SERVICE STUDY

Q. Please explain why the Company chose the particular cost allocation methodology utilized in its proposed gas cost of service study.

A. The Company selected the Peak and Average cost allocation methodology for the cost of service study in the instant filing because it reasonably reflects the principles previously deemed appropriate by this Commission for establishing a cost allocation methodology, as enunciated in Docket No. UG-940814, the Company's last rate proceeding that fully litigated gas cost of service issues.

Although the Peak and Average methodology may not reflect the Company's preferred approach, it finds the methodology to be an acceptable framework for structuring a moderate approach to its rate spread proposal in this proceeding.

Q. Does the modified Peak and Average method reasonably reflect the nature of a gas utility's costs and the primary system design considerations that give rise to those costs?

A. Yes. It is a widely accepted principle within the utility industry that the measure of load factor is a key determinant in establishing a linkage between the gas consumption characteristics of an LDC's customers and the particular costs incurred by the LDC in serving those customers. The modified Peak and Average method directly captures this principle in the way it is applied to an LDC's cost of service and customer classes. The method is a variation of a cost allocation method that has been accepted and used by utility regulatory commissions in other states, including Illinois, New Jersey, Michigan, and Pennsylvania.

In the *Gas Distribution Rate Design Manual*, published by the National Association of Regulatory Utility Commissioners ("NARUC"), it is stated that

> [t]he most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.

It goes on to describe the Average and Peak Demand Method as follows:

> This method reflects a compromise between the coincident and non-coincident demand methods. Total demand costs are multiplied by the *system's load factor* to arrive at the capacity costs attributed to average use and are apportioned to the various

> customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and *tempers the apportionment of costs between the high and low load factor customers*. (Emphasis added.)

Q. Please explain the method used by the Company to determine the peak day demand included in its modified Peak and Average Method?

A. The Company determined its peak day demand for cost allocation purposes using a demand level that reflects the system design peak day. This method results in a peak day demand for the Company of approximately 8,638,917 therms based on a 52 Heating Degree Day ("HDD") level.

Q. Why did the Company utilize its design day demand rather than its actual peak day demand as a demand allocation factor?

A. Use of the Company's design day demand is superior to using its actual peak day demand or an historical average of multiple peak day demands over time for purposes of deriving demand allocation factors for a number of reasons. These include:

1. PSE's gas system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred on the basis of an average of peak demands.

2. Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time.

3. Design day demand provides more stable cost allocation results over time.

Q. Please explain why the Company's design day demand best reflects the factors that actually cause costs to be incurred.

A. The Company relies upon design day demand in acquiring upstream gas supply-related resources and in designing its distribution facilities required to service firm service customers. Perhaps more importantly, design day demand directly measures the gas demand requirements of the Company's firm service customers which create the need for the Company to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis.

The development of PSE's gas planning standard is discussed at length in its 2005 Least Cost Plan. The Company has provided a copy of the relevant sections as Exhibit No. ___(WFD-9) and Exhibit No. ___(WFD-10). The Company performed a cost-benefit analysis that takes into consideration the value to customers of reliability of service with the incremental costs of the resources necessary to provide that level of reliability at various temperature levels. Based on the results of that analysis, PSE established its planning standard at a level of 52 Heating Degree Days or an average temperature of 13 degrees Fahrenheit. At this level, the planning standard will meet 98 percent of historic peak day temperatures (since 1950), thereby providing firm customers with a reasonable degree of planning cushion.

With regard to delivery system planning, guidelines are established for installation, maintenance and operation of the Company's physical plant in order to balance cost, safety and operational requirements. PSE categorizes its distribution system needs primarily as "capacity" and "reliability." The performance of the distribution system is judged with these needs in mind, which forms the basis for system planning. PSE's performance criteria for its gas system are defined by:

- Safety and compliance,
- The temperature at which the system is expected to perform,
- The nature of the service (i.e., firm versus interruptible service),
- The minimum pressure that must be maintained in the system,
- The maximum pressure acceptable in the system, and
- The cost customers are willing to pay for target levels of performance.

These performance criteria provide the foundation for PSE's infrastructure planning. Because of the Company's reliance on its design day planning standard in the acquisition of upstream supply and capacity resources and in its distribution system planning and design criteria, the true cost causative factors of the Company's operations are captured by utilizing the design peak day requirements within its cost of service studies.

Q. Please explain why use of design day demand provides more stable cost allocation results over time.

A. By definition, the Company's design day peak is as stable a determinant of planned capacity utilization as you can derive. If it were not a stable demand determinant, the design of PSE's gas system and supply portfolio would tend to vary and make the installation of facilities and acquisition of supply resources and capacity a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocation factors available based on either actual peak day demand or the averaging of multiple peak days.

VIII. REVENUE ALLOCATION AND RATE DESIGN PRINCIPLES

Q. How can the Company's cost of service study results provide guidelines for rate design?

A. The cost of service study ("cost study") results provide cost guidelines for use in evaluating class revenue levels and rate structures. When evaluating class revenue levels, the rate of return results and resulting revenue-to-cost ratios show that rates charged to certain rate classes recover less than their indicated cost of service. Conversely, rates for other rate classes recover more than their indicated cost of service. By adjusting rates accordingly, class revenue levels can be brought closer to the indicated cost of service (or "parity"), resulting in class rates of return nearer the system average rate of return. Thus, rate levels will be more in line with the cost of providing service.

Q. Do the cost study results provide guidance in establishing rates within each rate class as well?

A. Yes. The classified costs, as allocated to each class of service within the cost study, provide useful cost information in determining the level of customer, demand and commodity charges.

Q. Please explain how the classified costs can be used for rate design.

A. If the classified costs presented by Ms. Phelps in Exhibit No. ___(JKP-4) at 2-4, the Unit Cost Summary by Function, are used to set three-part rates (Customer, Demand and Commodity), the Company's operating expenses and return on investment in its pro forma revenue requirement will be recovered.

Q. Should other factors be considered that would prevent the company from simply translating the unit costs into rates for the various tariff services?

A. Yes. Completely restructuring a utility company's rates in this manner is usually not possible due to the resulting adverse impact of the revenue allocation on certain customer classes, particularly for smaller, low load-factor customers. However, the use of three part rates is becoming more widely accepted as the delivery of utility services continues to evolve. The unit costs do provide useful information for the design of portions of tariff services, in particular for establishing cost-based customer charges. The unit costs also can be used to design demand charges where either demand metering is available, as is the case with PSE's automated meter reading ("AMR") equipment, or where algorithm-based billing demands can be determined. Demand-based rates provide for a charge based upon the maximum demand imposed by a customer on the utility's system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service.

Q. Please describe other policy considerations or criteria that should be used in the design of utility rates.

A. Utility rate design should recognize that rates must be just and reasonable and not cause undue discrimination, that is, rates should be based on established principles of fairness, equity and sufficiency. Thus, customer impact considerations must be factored into the rate design process. Market conditions within the utility service territory with respect to the general economic environment and competitive fuel prices, where appropriate, should be reviewed. Another important consideration is the financial stability of the utility. Toward this goal, it is generally an unsound ratemaking practice to recover a substantial portion of fixed costs, such as customer related costs which bear no relationship to customer consumption patterns, in the volumetric portion of the rate schedule. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of gas can be extremely sensitive to the vagaries of weather patterns and changing consumption characteristics. Recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well-founded energy choices.

Q. How then are the foregoing guidelines and criteria incorporated into the rate design process?

A. A reasonable balance between the various cost guidelines and other criteria must be established in the process of designing rates, which consists of both the recovery of the revenue requirement from among the various customer classes and the determination of rate structures within tariff schedules. Economic, social, historical, and regulatory policy considerations all impact the rate design process. Both quantitative and qualitative factors must be evaluated in reaching a final rate design.

IX. THE COMPANY'S GAS REVENUE DECOUPLING PROPOSAL

A. <u>The Company's Proposed GRNA Addresses Fundamental Ratemaking Challenges that Harm PSE and its Customers</u>

Q. Why is PSE proposing its Gas Revenue Normalization Adjustment ("GRNA") at this time?

A. PSE is proposing this ratemaking mechanism in this proceeding for three important and interrelated reasons.

1. It addresses a fundamental problem in the utility ratemaking process, which is that gas volumes that will be used by customers in future periods cannot be accurately forecasted at the time rates are set. As a result, the base rates that the utility derives in its rate case, and that the Commission approves, cannot be expected to reflect the level of base rates required in future periods to fully recover the Company's approved level of fixed operating costs.

2. It will enable PSE to solve the dilemma it faces as it promotes energy efficiency programs for its gas customers, that is, for every therm saved due to energy conservation, PSE fails to recover another unit of its authorized distribution margin.

3. It will minimize the impact of weather on PSE's financial condition.

1. <u>Shortcomings of the Traditional Utility Ratemaking Process</u>

Q. Please describe the shortcomings of the traditional utility ratemaking process that the GRNA is designed to address.

A. Very simply, the traditional ratemaking process used to design a utility's base rates is a static process that relies upon historically based assumptions of customer gas usage and average weather conditions. However, the assumptions regarding gas usage seldom if ever reflect the actual gas usage levels experienced by the utility in subsequent time periods, due in part to the uncertainty of weather. This unpredictability in gas usage requires a much more dynamic process to ensure that a utility's base rates will reflect the previously-approved costs recoverable in this portion of the utility's rate structure. Rather than directly tying a utility's base rates to the normalized gas use per customer assumed in its most recently-completed rate case, and requiring those rates to remain fixed until the utility's next rate case, the utility should have the ability to periodically adjust its base rates to reflect the fluctuations in actual gas volume sales from those assumed in its rate case. Without this fundamental change, the utility will continue to "live or die" financially by the sales level it achieves during any 12-month period relative to the previous sales level and average weather used to set its base rates.

Q. Does the traditional utility ratemaking process create a disincentive for a utility to promote energy efficiency for its customers?

A. Yes. Traditional utility ratemaking requires that rates be designed to capture most of the approved revenue requirements for fixed costs through volumetric rates, so that a utility can fully recover these costs only if its customers consume a certain level of gas. As previously discussed, this level of gas is typically established in the utility's most recently completed rate case based upon its historical gas volumes. However, basing the utility's rates upon a set level of gas volumes creates a significant financial disincentive for it to aggressively promote energy efficiency for its customers. When customers use less gas, the utility's financial performance almost always suffers because recovery of fixed costs is reduced in proportion to the reduction in gas sales.

This presents a particular dilemma for PSE as it follows the direction set out in its 2005 Least Cost Plan to provide consumption-reducing energy efficiency programs for its customers:

> On the gas side, PSE has provided energy efficiency services since 1993, installing enough conservation measures through 2004 to be currently saving a cumulative total of 1,114,267 decatherms in 2004 – half of which has been achieved since 2002. … PSE's 2004 gas efficiency programs saved a total of 318,000 decatherms, putting the Company on track to achieve its two-year gas savings goal of 500,000 decatherms by the end of 2005.[2]

Q. Please explain how weather influences the ratemaking process for a gas utility.

A. As part of the ratemaking process, test year volumes and therefore the related revenues of a gas utility are weather-normalized. The weather-normalized test year used by the utility is designed to be the most reasonable picture of the operating conditions expected to occur during the period in which the utility's

[2] PSE April 2005 Least Cost Plan, Chapter VII, Demand – Side Resources, pages 1 and 3.

approved rates and charges are in effect. The process of weather-normalizing revenue consists of either increasing or decreasing actual gas volumes, in relative terms, by the difference between normal temperatures established for the utility's service area and actual temperatures experienced during the chosen test year. Weather normalization is further discussed in this case in the prefiled direct testimony of Dr. Jeffrey Dubin, Exhibit No. ___(JAD-1T).

Q. What standard measure is used to describe relative temperatures for purposes of setting gas rates?

A. A "heating degree-day" is a standard energy industry measure of the relative coldness of the temperatures experienced, based on the extent to which the daily mean temperature falls below a base temperature, which often is set at 65 degrees Fahrenheit ("°F"). For example, on a day when the mean temperature is 35^{O}F, there would be 30 heating degree-days experienced.

Q. How are weather-normalized gas volumes used to derive a gas utility's base rates?

A. While the following explanation is somewhat over-simplified, essentially the utility's volumetric rates and charges for gas service are derived by simply dividing the appropriate costs, or portion of the utility's revenue requirement not otherwise collected through fixed monthly charges, by the weather-normalized gas volumes. These volumetric rates are designed to provide the utility with an opportunity to recover the significant level of fixed costs it incurs to provide utility service, at the levels determined in the utility's last completed rate case. Fixed costs are costs incurred by a utility that do not vary with the amount of gas delivered to customers. For PSE, these costs are composed of operation and maintenance costs, administrative and general expenses, depreciation, taxes, and return on investment. As defined, these costs do not vary in the short-term with changes in temperature.

Q. Why does this pose a problem?

A. If actual temperatures are normal, the utility has a reasonable opportunity to fully recover its fixed costs of service at established levels and customers have a reasonable chance that they will not pay more to the utility than is required to cover the fixed costs that the base rates were designed to recover. Unfortunately, normal temperatures seldom, if ever, occur. Therefore, as a result of abnormal weather, the earnings (i.e., margin revenues) of a utility such as PSE can vary widely from the levels authorized by the Commission.

Q. Please explain the the meaning of the terms "margin" and "margin revenues."

A. The terms "margin" and "margin revenues" relate to a utility's total cost of service exclusive of purchased gas expenses and any other expenses that simply are treated as "flow-through" items in rates (e.g., revenue taxes, conservation program riders, etc.). A utility's margin reflects its overall costs of operations, including a fair and reasonable return on its utility assets. Margin revenues provide the basis upon which the utility recovers its margin, with the level of margin approved by the regulator in the utility's most recently completed general rate case.

Q. Is it important that a utility such as PSE recover the margin that was authorized by the Commission in the Company's most recent rate case?

A. Yes. A utility's financial health directly relies upon its ability to recover the cost of service inherent in the margin level approved by the Commission through the margin revenues upon which the utility's base rates were previously established.

Q. Please explain how fluctuations in weather over time impact how much a gas utility's temperature-sensitive customers pay for gas utility service?

A. Under traditional ratemaking methods, if actual temperatures were colder than normal, temperature-sensitive gas customers would use more gas, pay more for utility service, and potentially overpay their share of fixed costs. This occurs because the unit rates used to recover fixed costs are not reduced to recognize the higher gas volumes used by customers during colder weather. Since the gas utility's level of fixed costs does not change, the higher gas volumes applied against the same unit rate would generate higher non-gas revenues than the level of fixed costs established for ratemaking purposes.

In warmer than normal weather, the reverse situation will occur. Customers' gas usage would decrease with warmer temperatures, thus generating lower margin revenues than required to recover the gas utility's total fixed costs that do not decrease due to warm weather.

2. <u>These Shortcomings Impact PSE</u>

Q. Historically, has PSE experienced a decline in gas use per customer?

A. Yes. Pages 1 through 4 of Exhibit No. ___(RJA-4) demonstrate that over the last eleven (11) years, the annual average use per customer has declined in PSE's Residential, Commercial and Industrial General, and Special Commercial Heating service classes. The yearly decline in residential use per customer has averaged approximately 1.2% since 1994 on a weather-adjusted basis and PSE expects this trend to continue into the future. This decline is consistent with a decline in use per customer in the U.S. residential market since 1980, as shown in the results of a recent American Gas Association study that is provided in Exhibit No. ___(RJA-5).

PSE's customers have reduced their gas consumption, not unlike other gas customers throughout the U.S.[3], primarily by the use of increased efficiency gas

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[3] On average, natural gas use per customer in the U.S. has been declining by about one percent per year since 1980. See the American Gas Association Energy Analysis entitled, "Forecasted Patterns in Residential Natural Gas Consumption," 2001-2020, EA 2004-04 (dated September 24, 2004) and "Patterns in Residential Natural Gas

appliances and tighter, more energy efficient homes as a result of improved insulation and window products and higher building code standards. Information from PSE's own Residential Appliance Saturation Surveys may help explain the impact on use per customer. In terms of residential dwelling types, there has been a significant percentage increase in the multifamily sector, from about 8% in 1997 to 21% as of the 2004 survey. Multifamily dwellings also represent a higher percentage of the overall housing type mix for PSE's gas customers, growing over that same period from 3% to 9%. Because they are typically smaller than single family homes, multifamily dwellings use less energy for space heating.

The PSE surveys also reveal that about a quarter of space and water heating equipment has been replaced since 1997 and the new equipment must comply with more stringent efficiency standards. While the surveys were not intended to be a comprehensive inventory of energy efficiency improvements, they also provided evidence related to the installation of insulation and other energy efficiency measures such as ceiling, wall and heat duct insulation, insulated windows and doors, and low-flow showerheads.

Q. What reference point should be used to review PSE's decline in use per customer?

A. The reference point should be the use per customer levels established in PSE's

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Consumption", 1997-2001, EA 2003-01 (dated June 16, 2003).

past rate cases. Referring to Page 1 of Exhibit No. ___(RJA-4), the annual "baseline" use per customer for the Residential class established in Docket Nos. UG-950278, UG-011571 and UG-040640 to design PSE's base rates was approximately 985, 868 and 878 therms per customer, respectively. One can readily see that over the succeeding years since each of those rate cases was completed, PSE rarely (twice) experienced an equivalent annual gas sales level. Similar assessments can be made for PSE's Commercial and Industrial General and Special Commercial Heating classes.

Q. What conclusion do you reach from this assessment?

A. PSE's "baseline" use per customer level established in its prior rate cases was not representative of the actual use per customer it experienced in subsequent years. In fact, the data in Exhibit No. ___(RJA-4) demonstrates that the baseline use per customer levels were high relative to the actual amounts, and that trend is expected to continue without a resetting of PSE's baseline use per customer levels. To the extent the baseline use per customer level is not representative of PSE's expected future trends, its base rates will not properly recover from customers the fixed costs incurred to provide them with gas delivery service.

Q. Besides the energy efficiency gains of PSE's customers, what other factors caused the variability in annual use per customer depicted in Exhibit No. ___(RJA-4)?

A. The variability in use per customer was also caused by the variation in weather during that same period.

Q. Have you prepared a graphical depiction of the historical weather pattern experienced by PSE?

A. Yes. The historical weather pattern is presented in Exhibit No. ___(RJA-6). The weather is presented on an annual and monthly basis as the change in heating-degree days ("HDDs") from PSE's normal weather (and its monthly components). As described in the testimony of Dr. Dubin, PSE's normal HDD level is based on the 30-year average, calculated from National Oceanic and Atmospheric Administration ("NOAA") temperature data, as reported at Seatac airport. Clearly, there is a wide variation in actual weather compared to normal weather. Over the eleven-year period from 1995 to 2005, as shown in Exhibit No. ___(RJA-6), there were about an equal number of years of above-normal weather and below-normal weather, and weather varied widely, from 17% warmer-than-normal to 8.3% colder-than-normal years. The variability of weather has very significant implications for PSE's ability to achieve its authorized margin revenue level, which is premised upon normal weather.

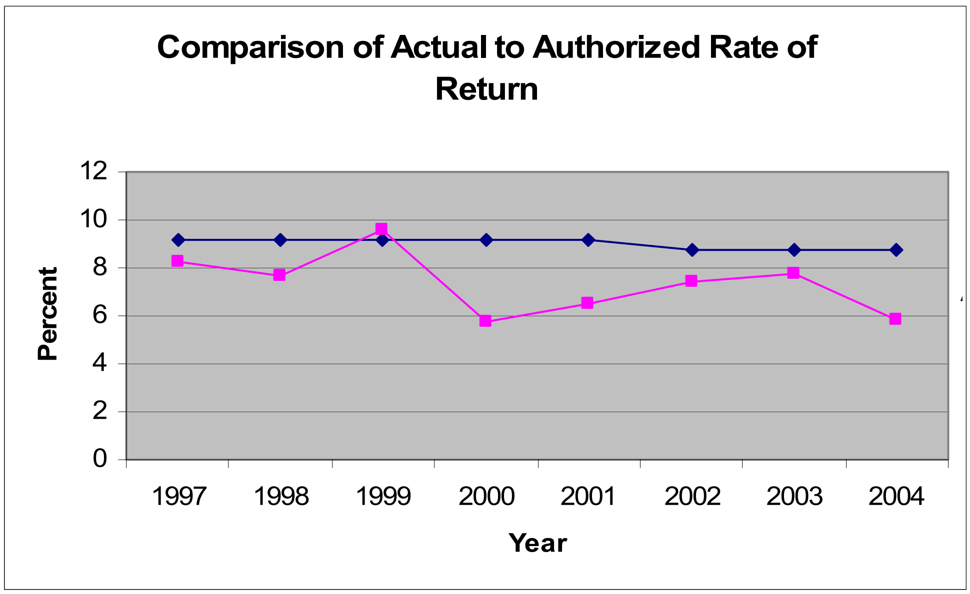
Q. Have you examined the variability in the margin revenues collected historically by PSE?

A. Yes. Exhibit No. ___(RJA-7) presents the margin impact experienced by PSE in its residential, commercial and industrial general, and commercial heating service classes due to fluctuations in gas volumes caused primarily by declining use per customer and variations in weather from normal levels. Between 1995 and 2005, PSE incurred margin losses in nine of the eleven years. The average yearly margin losses (i.e., the loss of margin revenues derived from PSE's Delivery Charges, which are volumetrically designed) during that period amounted to approximately $9.8 million. Moreover, in six of the last eleven years, the Company experienced margin losses that were in excess of 5% of its total approved margin level for these same rate classes, as adjusted for the yearly change in customers.

Q. How has PSE's historical experience with the variability in its margin recovery been reflected in the Company's achieved rate of return levels?

A. The following graphical representation provides a comparison of the Company's actual versus Commission authorized rates of return for its gas business in the post-merger (i.e., Washington Energy and Puget Power) period, as shown in the Company's Commission Basis Reports. While recognizing that the Company's actual results of operations also reflects its ability to effectively manage those aspects of its business that are under its control, the trend in actual rate of return

("ROR") since 1997 tracks the margin deficiency shown in Exhibit No. ___(RJA-7) for the same period. The only instance during this eight year period in which the Company achieved its authorized ROR was 1999, a 7.5% colder-than-normal year and the only one where the Company's margin variance was positive.



Source: WUTC Gas Commission Basis Reports.

Q. Is PSE's experience unusual in the gas distribution industry?

A. No. This type of under-recovery of fixed costs is not unique to PSE. In fact, it was quite commonplace in the recent past in the gas distribution segment of the energy industry. To address fixed-cost volatility, many gas utilities proposed ratemaking solutions that were approved by their regulators, such as weather normalization adjustment clauses and increases to their monthly service or customer charges to more closely reflect in rates their fixed costs of service.

3. Decoupling is the Preferred Ratemaking Solution to These Problems

Q. What is your recommended ratemaking solution to address the impact of weather and declining use per customer on PSE's ability to recover its approved margin revenue level?

A. The proposed ratemaking solution to these chronic problems is for the Commission to approve the Company's proposed decoupling mechanism, which breaks the link between the Company's gas sales levels and the margin collected from its customers. This solution will result in a better alignment of the interests of the Company and its customers, promote energy utility efficiency, and it will be beneficial for both PSE and its customers.

The appropriateness of this type of solution was clearly recognized by the Oregon Public Utility Commission ("OPUC") in its approval in 2002 of a revenue decoupling mechanism for Northwest Natural Gas Company ("NW Natural"). In its Order approving NW Natural's proposed revenue decoupling mechanism, the OPUC emphasized the need to change regulatory policy to encourage the efficient use of energy resources:

> We are persuaded that the connection between profits and sales should be severed. As long as the regulatory system provides that increased sales may lead to increased profits, a conflict will exist between the motivation to sell energy and the motivation to

promote reduction in energy consumption.[4]

It should be noted that NW Natural's proposed revenue decoupling mechanism was acceptable to all parties in its rate proceedings as shown by its inclusion in the utility's settlement agreement, which was approved by the OPUC.

On August 25, 2005, the OPUC reaffirmed its support of the revenue decoupling concept when it adopted an extension of NW Natural's mechanism for four more years.[5] This extension was based, in part, upon the results of an independent study of the mechanism's effectiveness, which concluded that the mechanism has been effective in reducing the variability of distribution revenues and in altering NW Natural's incentives to promote energy efficiency.

Q. Please explain the concept of decoupling as it relates to utility ratemaking.

A. Decoupling is a ratemaking and regulatory tool that is designed to break the link between a utility's earnings and the energy consumption of its customers. While such a ratemaking mechanism can take several forms, the basic approach consists of defining a target for the utility's revenues (i.e., non-gas or margin revenues) and placing over- and under-collections compared to the target in a deferred account for refund or recovery in a subsequent period. Under these mechanisms, the gas utility cannot increase its earnings by increasing its sales volumes because

[4] Oregon Public Utility Commission, Order No. 02-634, page 2 (dated September 12, 2002).

[5] Oregon Public Service Commission, Order No. 05-934 (dated August 25, 2005).

additional margin revenues are refunded to customers.

Q. Under the concept of decoupling, does it remain necessary to continue using some measure of sales volumes to compute a utility's rates?

A. Yes. However, under a revenue decoupling mechanism, the sales level assumed in the utility's last rate case upon which its base rates were designed is not blindly adhered to for purposes of representing the level of sales the utility actually achieves in a future 12-month period. By utilizing customers' actual sales levels once they are known, and relating those amounts to the utility's approved level of margin revenues, rates can be adjusted to recover the appropriate level of revenues to produce the margin authorized by the Commission. In other words, the utility's margins are no longer linked to its rate case sales level.

The de-emphasis of sales volumes in the operation of a revenue decoupling mechanism better recognizes the way consumers actually perceive, value, and purchase services offered by gas and electric utilities. A consumer does not look at utility services and consciously make a decision to purchase a certain number of therms of gas or kilowatt hours of electricity. Instead, the consumer purchases utility services to acquire light, heat, hot water, and a wide range of other consumer needs and conveniences. If over time consumers are able to acquire these needs and conveniences more efficiently, through adoption of energy conservation and energy efficiency techniques promoted by utilities and others, the utilities should not be penalized for these beneficial societal actions.

Q. Would implementation of a revenue decoupling mechanism reduce the precision by which the utility's rates are determined?

A. No. Under a revenue decoupling mechanism, the Company's base rates will continue to be computed by rate class, they will continue to be designed to recover the Company's approved level of margin revenue, and they will reflect the customers' actual historical gas consumption.

Q. Does the use of this type of ratemaking mechanism guarantee that the utility will achieve the level of financial performance authorized by the Commission?

A. No. The utility still must actively manage its costs and insure that any growth in customers is economic in order to achieve its financial expectations. The "re-basing" of the utility's sales levels as described above only takes gas volumes out of the ratemaking equation – it does not eliminate any of the utility's responsibilities to prudently manage the business factors that are under its control.

Q. Have other energy industry participants endorsed the concept of revenue decoupling to address the inherent disincentive that utilities face in promoting energy efficiency?

A. Yes. With the increased volatility in energy prices and the resultant unprecedented upward pressure being placed on customers' utility bills, many energy industry groups now are publicly advocating a renewed focus on promoting cost-effective energy efficiency measures to help relieve these consumer burdens. These groups include the American Gas Association ("AGA"), the Natural Resources Defense Council ("NRDC"), the Alliance to Save Energy, and the American Council for an Energy Efficient Economy ("ACEEE"). Most importantly, these same groups have also realized that to achieve these consumer benefits, a fundamental change must be made to the utility ratemaking process. They have endorsed the concept of a revenue decoupling mechanism as their solution to the problem.[6]

In its July 2004 Resolution on Gas and Electric Efficiency, the National Association of Regulatory Utility Commissioners ("NARUC") endorsed revenue decoupling as a ratemaking concept that provides earnings stability for utilities and removes the disincentives for promoting energy conservation. In particular, NARUC made reference to the above-mentioned groups and stated that:

> Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure the utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations on retail sales.

In its November 2005 annual convention, NARUC adopted a second resolution

[6] Joint Statement of the American Gas Association and the Natural Resources Defense Council submitted to the National Association of Regulatory Utility Commissioners ("NARUC"), dated July 2004. A similar joint recommendation was submitted in November 2003 to the NARUC by the NRDC and the Edison Electric Institute ("EEI"), wherein it was stated: "To eliminate a powerful disincentive for energy efficiency and distributed-resource investment, we both support the use of modest,

encouraging state utility regulators and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices. As part of this review, NARUC further encouraged state utility regulators and other policy makers to consider in their review innovative rate designs including "energy efficiency tariffs" and "decoupling tariffs." The resolution recognized several utilities that have received approval of revenue decoupling mechanisms, fixed-variable rates, and other innovative rate design approaches.

Another example of the widening recognition in the industry for regulatory policy changes that break the link between utilities' electric and gas sales and their profits appears in a special report recently prepared by the Northwest-based, non-profit environmental organization Climate Solutions. This paper culminated from a year-long collaborative process involving regional and national energy and economic development experts on the subject of "smart energy" technology applications to optimize the electrical power system.[7] While describing a series of regulatory changes to overcoming the disincentives for investor owned utilities to pursue smart energy technologies, the report supports the development of

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regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes."

[7] "Powering up the Smart Grid: A Northwest Initiative for Job Creation, Energy Security and Clean, Affordable Electricity," a Special Report from Climate Solutions, July 2005.

decoupling plans that provide "win-win solutions" for utilities and their customers and cites the Northwest Natural operating model.

Q. Which state utility regulatory commissions have approved the concept of revenue decoupling?

A. In addition to the state of Oregon, which was mentioned earlier with respect to Northwest Natural's decoupling mechanism, the utility regulatory bodies in the states of Maryland, California, and North Carolina have approved the concept of revenue decoupling. Specifically, revenue decoupling mechanisms have been approved for Baltimore Gas & Electric Company, Washington Gas, Southwest Gas Corporation, and Piedmont Natural Gas Company. In addition, eight gas utilities in six states have proposed revenue decoupling mechanisms in currently pending regulatory proceedings. This list does not reflect Cascade Natural Gas Corporation's Conservation Alliance Plan, which was introduced and later withdrawn here in Washington State.

Q. Are you familiar with the Natural Gas Decoupling Rulemaking initiated by the WUTC last year?

A. Yes. As stated in its "Summary, Analysis of Comments and Decision to Close Docket without Action," issued on October 17, 2005, in Docket No. UG-050369, the Commission initiated the rulemaking to assess whether it should develop a general rule or policy on the approach to be taken with regard to decoupling.

Largely because of the varied potential alternative approaches that were identified and the disparate geographic, economic, and technological circumstances of the natural gas utilities in the state, the Commission decided not to pursue a rulemaking on the subject in favor of a case-by-case approach by each utility in general rate case filings. Companies that believe revenue decoupling would overcome disincentives related to the pursuit of energy efficiency and conservation programs were invited to propose, within the context of a general rate case filing, a decoupling mechanism that addresses their own particular circumstances and needs.

Q. Has the financial community recognized the impact of conservation on gas margins and financial stability in the gas distribution utility sector, and the value of implementing ratemaking solutions such as revenue decoupling mechanisms to address these conditions?

A. Yes. For example, Moody's Investor Service issued a *Special Comment* report that specifically addressed this topic. On the topic of ratemaking concepts such as revenue decoupling mechanisms (or "conservation" tariffs), the Moody's report stated:

> Moody's believes that having utility rate designs that compensate the gas LDCs for margin losses caused by variations in gas consumption due to conservation as with variations due to weather, would serve to stabilize the utility's credit metrics and credit ratings. Utilities having these ratemaking mechanisms also tend to

carry 'A' credit ratings.[8]

Q. Does the Company's proposed decoupling mechanism represent an effective solution to the aforementioned problems it has experienced with regard to the impact of weather and historical declines in use per customer on margin recovery?

A. Yes. PSE's proposed Supplemental Schedule No. 118, GRNA, is fair, symmetrical, and beneficial to the Company and its customers for the following reasons:

1. When it is colder-than-normal, customers will not ultimately overpay for the Company's fixed costs, and the Company will not over-recover margin. Conversely, when it is warmer-than-normal, customers will not underpay for the Company's fixed costs, and the Company will not under-recover margin.

2. The decoupling mechanism upholds the Commission's assumption of normal weather in setting rates – it simply allows for the recovery of margin as is intended through the weather-normalization of the volumes underlying base rates.

3. The decoupling adjustment relies upon realistic gas volume levels for computing the Company's unit rates.

4. The mechanism is a more effective ratemaking method to address the issue of margin volatility on a year to year basis (compared to budget billing and monthly service charge increases).

5. Under its proposed decoupling mechanism, the Company will be able to continue promoting energy efficiency and conservation programs for its customers without the continual real threat of margin losses due to declining gas sales per customer.

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[8] "Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector," Special Comment Report, Moody's Investor Service (June 2005).

B. The Structure of PSE's Proposed Decoupling Mechanism, the GRNA

Q. Please summarize the structure of the Company's decoupling proposal.

A. The Company's decoupling proposal is designed to stablilize the level of margin revenues that are provided by customers to the Company on an annual basis. The proposal will periodically adjust the Company's distribution service rates to recover the margin revenues per customer, as established in this general rate case, that fluctuate due to variances in gas volumes caused primarily by weather, energy efficiency gains and conservation efforts by its customers. The decoupling mechanism will apply to the Residential General Service Schedule 23, Commercial and Industrial General Service Schedule 31, Special Commercial Heating Service Schedule 36, Special Multiple Unit Housing Service Schedule 51, and Propane Service Schedule 53. These are the customer classes that have exhibited weather sensitivity and trends in declining use per customer, as shown earlier in Exhibit No. ___(RJA-4).

Q. How will the decoupling adjustment be determined?

A. Each month, the Company will compute either a credit or a charge to a Decoupling Adjustment Account by comparing the actual margin revenues provided by the applicable classes to predetermined target margin revenues and either crediting the over-collection or charging (debiting) the undercollection to the account. The GRNA mechanism is designed to stabilize the level of revenues provided by these customers each month. The target margin revenues will consist of the Commission authorized margin revenue levels determined in this general rate case for the applicable classes. The authorized margin revenues will be adjusted for the margin impact from the month-to-month change in the number of customers in these classes. This customer adjustment will account for the margin provided by the monthly customer charge and the distribution charge, based on the monthly average use per customer determined in this case.

Mechanically, the credit or charge to the Decoupling Adjustment Account is determined through the following series of calculations:

a. A customer change adjustment is calculated by comparing the corresponding pro forma test year number of customers to the current month's actual number of customers to determine a change in customers:

   i. The change in customers is multiplied to the respective monthly customer charges to determine the customer charge impact;

   ii. A volumetric impact is determined by multiplying the corresponding monthly test year average therms per customer by the applicable distribution charge rate and by the change in customers to determine the volumetric portion of the customer change adjustment;

   iii. The total customer change adjustment is calculated by adding the customer charge and distribution charge impact by class.

b. The required margin revenue adjustment is then calculated:

   i. The monthly pro forma test year base revenues (the sum of the customer charge and distribution charge revenues) are increased or decreased by the customer change adjustment to determine the target margin revenue.

   ii. The actual calendar month margin revenue is subtracted from the monthly target revenue to calculate the required revenue adjustment, the credit or charge to the Decoupling Adjustment Account.

Exhibit No. ___(RJA-8**)** provides a detailed example of the operation of the Decoupling Adjustment Account.

Q. When will the decoupling adjustment be applied to customers' bills?

A. The balance in the Decoupling Adjustment Account will be collected or refunded to customers on an annual basis by dividing the Decoupling Adjustment Account balance by the projected sales for the applicable customer classes over the decoupling adjustment recovery period. Supplemental Schedule No. 118, GRNA, in Exhibit No. ___(RJA-9) provides greater detail on the application of the decoupling adjustment to the applicable customer classes.

Q. Have you evaluated the expected performance of the proposed decoupling adjustment based on the Company's recent experience with weather variability and use per customer?

A. Yes. Exhibit No. ___(RJA-10) illustrates the results of a simulation of the operation of the Decoupling Adjustment Account and the determination of the GRNA rates for Rate Schedule Nos. 23/53, 31, 36 and 51 during a three-year period. Customer billing adjustments under the GRNA were computed for the average customer in each of these rate classes as if the GRNA was in effect during this three-year period. The simulation used as a base the sales and customer levels for these classes that are included in the Company's test year for this case, the weather experienced by the Company during its last three calendar years (2003 – 2005), and the projected average use per customer by class from the Company's "Customer and Sales Forecast."

Q. Please describe the results of your analysis for the Company's Rate Schedule Nos. 23/53.

A. The analysis shown on Page 1 of Exhibit No. ___(RJA-10) presents the results of a simulation of the monthly deferrals in the Decoupling Adjustment Account under GRNA for these residential customers. At the end of year one, the balance in the Decoupling Adjustment Account was $14.4 million. When spread over the projected therms for the residential customers over the succeeding twelve month period, the adjustment per therm would be $.0261. As a point of reference, the average monthly gas bill of the average-sized residential heating customer is approximately $80.00, at current rates. At an adjustment rate of $.0261 per therm, the amount of the GRNA adjustment would range from $3.42 in a typical winter month to $.52 in a typical summer month.

Continuing with the simulation, the balances in the Decoupling Adjustment Account at the end of year two and three were $19.3 million and $15.8 million, respectively. These deferral balances translate into average bill impacts for the residential customers of $.0342 per therm and $.0274 per therm, or $2.33 and $1.87, respectively.

As demonstrated by the analysis, the annual frequency of the decoupling adjustments to customers' bills should address concerns over potential volatility caused by a employing a monthly adjustment.

Q. Please describe the results of your analysis for the Company's Rate Schedule Nos. 31, 36 and 51.

A. The analysis shown on Pages 1 and 2 of Exhibit No. ___(RJA-10) presents the simulation of the monthly deferrals in the Decoupling Adjustment Account under GRNA for the customers in these rate schedules. For example, at the end of year one, the balance in the Decoupling Adjustment Account was $2.2 million for Rate Schedule No. 31 ("Rate 31"). When spread over the projected therms for these customers over the succeeding twelve month period, the adjustment per therm would be $.0026. As a point of reference, the average monthly gas bill of the average-sized commercial customer served under Rate 31 is approximately $304.00. At that adjustment rate, the amount of the GRNA adjustment ranged from $1.35 in a typical winter month to $0.31 in a typical summer month with an average monthly bill impact of $0.73.

Continuing with the simulation, the balances in the Decoupling Adjustment Account at the end of year two and three were $3.2 million and $1.9 million, respectively. These deferral balances translate into average bill impacts for the average Rate 31 commercial customer of $1.13 and $0.65, respectively.

Similarly, the operation of the GRNA mechanism is modeled under the assumptions outlined earlier for the Rate Schedule Nos. 36 and 51 customers on page2 of the exhibit.

C. The Interests and Objectives Served by the GRNA

Q. Please summarize how the interests of PSE and its customers are served by implementing the Company's GRNA proposal?

A. There are significant benefits to both PSE and its customers from implementing the Company's proposed GRNA, including:

1. The GRNA will break the link between the gas consumption of the Company's customers and its margin recovery and result in a better alignment of the interests of PSE and its customers.

2. The GRNA will address factors beyond the Company's control that contribute to under recovery of costs and the inability to achieve the level of returns that have been authorized by the Commission.

3. Under the GRNA, PSE will be able to continue promoting and expanding its energy efficiency programs for its customers in order to achieve the conservation goals established in its Least Cost Plan, without the continual real margin losses due to the resulting decline in gas sales per customer.

4. With the implementation of the GRNA, customers will pay each year approximately the same amount for gas delivery service as if the Company had experienced normal weather, which is the same basis upon which the Commission establishes PSE's base rates. Ultimately, the GRNA will result in a heating customer's annual bill more accurately reflecting the margin recovery amounts approved by the Commission in this rate case, while customers will recognize the results of their energy conservation efforts in the amount they pay for the gas commodity.

Q. Does the GRNA meet the objectives that PSE outlined in its comments to the Commission in the Natural Gas Decoupling Rulemaking proceeding and does it further address the general issues identified in the Summary document you referenced earlier?

A. Yes. PSE's objectives as enunciated in its comments submitted in the referenced generic proceeding have been addressed by its GRNA proposal as follows:

1. It reduces regulatory lag and recovers the costs incurred to serve customer that have been previously authorized by the Commission in a general rate case for recovery,

2. In its proposed form, the GRNA mechanism is compatible with PSE's billing and customer information systems,

3. It allows for full margin revenue recovery, based on the results from the last general rate case,

4. In the Company's view, its extensive and varied communications capabilities should provide its customers and other stakeholders an appropriate understanding of the GRNA, leading to consumer acceptance, and

5. As an annual adjustment to base rates, it should be relatively easy to administer by the Company and reviewable by the Commission Staff.

Regarding the open questions raised in the Commission's Summary document, PSE believes that its proposal embodies the elements that address those general issues, as they pertain to the Company's unique circumstances, in a straight-forward and relatively uncomplicated fashion. The Company has: (a) defined the scope of events to be covered by its proposed decoupling mechanism; (b) assessed the appropriate customer classes to be included; (c) designed the scope of the measurement and timing of the adjustments, and tested them against actual historical weather patterns, customer growth assumptions and usage projections; (d) incorporated ongoing growth and/or changes to the level of customers in the mechanism's design, which will provide a greater level of confidence that the resulting margin revenue target will reflect current conditions on the Company's system; and (e) addressed the potential impact on low income customers by constructing the GRNA as an adjustmet to the volumetric distribution charge and reduced potential volatility by limiting adjustments to an annual basis.

D. <u>Conclusion Regarding the GRNA</u>

Q. Please summarize any final recommendations you may have regarding the Company's Proposed GRNA.

A. In my professional opinion, the GRNA mechanism proposed by PSE is a necessary and appropriate means to solve the chronic problems faced by the Company that I discuss above. The GRNA is conceptually sound, aligns the interests of the Company and its gas customers, and will remove the very real margin deficiency that results from the Company's energy efficiency programs. It addresses a fundamental flaw in traditional gas utility rate design and is a ratemaking approach endorsed by energy trade associations and NARUC to further promote and expand the energy efficiency programs offered by gas utilities that are so critical to their customers' ability to moderate the impact of rising energy prices. For these reasons, I urge the Commission to approve the

Company's GRNA.

X. CONCLUSION

Q Does this conclude your testimony?

A. Yes, it does.

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