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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY Respondent.	DOCKET UG-18____

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Ronald J. Amen

COST OF SERVICE STUDY

Exh. RJA-1T

December 31, 2018

DIRECT TESTIMONY OF RONALD J. AMEN

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 17806 NE 109th Court, Redmond, Washington 98052.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Northwest Natural Gas Company ("NW Natural" or the "Company").

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

A. I am employed by Black & Veatch Management Consulting, LLC ("Black & Veatch") as a Director and I am a member of the Advisory & Planning Practice within Black & Veatch.

Q. Please describe the firm of Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Black & Veatch Management Consulting, LLC delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas.

Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis, and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline, and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution 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 40 years of experience in the utility industry, the last 21 years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before utility regulatory bodies and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as Exh. RJA-7 to my testimony.

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

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), UG-011571 (General Rate Case of Puget Sound Energy), UG-060267 (General Rate Case of Puget Sound Energy), UG-080546 (General Rate Case of NW Natural), UG-152286 (General Rate Case of Cascade Natural Gas), and UG-170929 (General Rate Case of Cascade Natural Gas). I have also previously appeared before the Commission on numerous occasions regarding various regulatory, customer contract and tariff matters.

Q. Have you previously testified before any other utility regulatory bodies?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and numerous state and provincial regulatory commissions.

Q. Please summarize your testimony.

A. In my testimony I present NW Natural's Cost of Service Study ("COSS") and discuss its results, and I present the various rate design proposals filed by NW Natural in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation
- NW Natural's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- NW Natural's Rate Design Proposals
- Residential & Non-Residential Class Bill Impacts

Q. Please provide a list of exhibits supporting your testimony.

A. The following exhibits accompany my testimony.

- Exh. RJA-2 Summary of COSS Results
- Exh. RJA-3 Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Exh. RJA-4 Analysis of Revenue by Detailed Tariff Schedule
- Exh. RJA-5 Residential Impact by Month
- Exh. RJA-6 Impact of Recommended Rate Changes
- Exh. RJA-7 Ronald J. Amen Curriculum Vitae

II. THEORETICAL PRINCIPLES OF COST ALLOCATION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded COSS is a useful tool for determining the allocation of NW Natural's revenue requirement among its customer classes. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Marginal cost studies can reflect actually incurred costs but often rely on estimates of the expected changes in cost associated with changes in utility service. Marginal cost studies are forward-looking to the extent permitted by available data. Marginal cost studies may be particularly useful for rate design and can also be used as a guide to determine how a utility's total revenue requirement should be allocated to its classes of service. Where it is important to send appropriate price signals associated with additional energy consumption by customers, an understanding of marginal cost may be useful. For a gas utility, detailed studies are not required to assess the impact of additional consumption by existing customers since the delivery system is built for design day requirements and energy conservation has reduced those requirements for most customers. Where new customers are added to the system, growth may increase design day requirements above an amount that existing facilities can serve. The principal factors driving new main investment are customer growth and the replacement of aging pipeline infrastructure such as bare steel and cast-iron mains to provide safe and reliable service for customers.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds marginal cost, but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed marginal cost, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

SAC is an important concept for NW Natural because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify 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 Local Distribution Company's ("LDC's") customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable COSS 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 Company 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.

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

A. The Company's 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 either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the way 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 minimum size distribution mains, services, meters, regulators and customer service 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 the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also 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 Company for its sales service customers.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer’s load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as 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 the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, 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. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. 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, as mentioned earlier. 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. Were direct assignments of plant made in the NW Natural COSS?

A. No. However, several special studies were performed, which will be discussed in the next section of my testimony.

III. <u>NW NATURAL'S COSS</u>

A. Process Steps and Structure of the Cost of Service Study

Q. Please describe the process of performing NW Natural's COSS analysis.

A. Three broad steps were followed to perform the Company's COSS: (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 (*i.e.*, gas supply), transmission, distribution and general. 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 class. Costs typically are allocated on customer, demand, commodity or revenue allocation factors.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing a COSS?

A. Yes. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q Why are these considerations relevant to conducting NW Natural's COSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility'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.

Q. Please explain why the physical configuration of the system is an important consideration.

A. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as, whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure based or a single-pressure based operation.

Q. What are the specific physical characteristics of the NW Natural's system?

A. The physical configuration of the NW Natural' system is a dispersed / multiple city-gate, integrated transmission / distribution and multi pressure-based system.

Q. What was the source of the cost data analyzed in the Company's COSS?

A. All cost of service data have been extracted from the Company's total cost of service (*i.e.*, total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does the availability of data influence a COSS?

A. The structure of the utility'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. NW Natural maintains detailed plant accounting records for many of its distribution-related facilities.

Q. How are the NW Natural customer classes structured for purposes of the COSS?

A. The COSS evaluated six customer classes:

Rate Schedule	Description
01	General Sales Service
02	Residential Sales Service
03	Basic Firm Sales Service
27	Residential Heating Dry Out
41	Non-Residential Sales & Transport Service
42	Large Volume Non-Residential Sales & Transport Service

In addition to these rate classes, the COSS includes the revenues from the Special Contract as a credit to the cost of service. The distribution revenues from this customer are treated as a credit since the nature of the contract does not allow for rate increases due to a general rate case.

Q. How do state regulatory policies bear upon a utility's COSS?

A. State regulatory policies and requirements prescribe whether there is a particular approach historically used to establish utility rates in the state. Specifically, state regulations set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the particular cost allocation method utilized by the utility. For example, in a Washington Natural Gas (now Puget Sound Energy) case, Docket No. UG-940814, the WUTC expressed a preference for the gas utility to utilize a costing methodology, Peak & Average, which allocates some fixed costs on the basis of annual use (or throughput) in order to reflect the proposition that a range of factors influence how gas transmission and distribution system costs are incurred and its significance in the cost study process. In its December 2016 Order in Docket Nos. UE-160228 and UG-160229 (*consolidated*), the WUTC instructed its staff to initiate a collaborative effort with the investor-owned Washington utilities and interested stakeholders to more clearly define the scope and expected outcomes for generic cost of service proceedings in an effort to establish greater clarity and uniformity in future cost of service studies.[1] That proceeding is ongoing at this time.

Q. Is the overall cost allocation approach utilized in NW Natural's COSS consistent with that utilized in the prior rate case that you cited?

[1] *Wash. Utils. & Transp. Comm'n v. Avista Corp., dba Avista Utils.*, Docket Nos. UE-160228, *et al.*, Order 06, ¶116 (Dec. 15, 2016).

A. Yes. The overall allocation approach is similar to that adopted by the WUTC in Docket No. UG-940814.

Q. Please describe the Peak & Average methodology in greater detail as it has been applied in the NW Natural COSS.

A. The Peak & Average ("P&A") methodology is a simplified version of the Average and Excess ("A&E") demand allocation methodology, also referred to as the "used and unused capacity" method. The A&E 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. The P&A methodology adopted in the referenced WUTC docket similarly weights the allocation of the utility's transmission and distribution system costs by the system load factor. The peak related portion of the P&A method is premised on the notion that investment in capacity is determined by the peak load(s) of the utility and therefore are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class. The peak demand allocation process might focus on a single system peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of several cold days, either consecutive or occurring over a period of several years, or it could be the expected contribution to the system peak under weather conditions for which the system was designed to serve, commonly referred to as a "design day." The peak demands utilized in the NW Natural

COSS are the respective design day demands for NW Natural's firm sales classes, consistent with the methodology used in the Company's most recent Purchased Gas Adjustment ("PGA") filing. While the PGA demand data does not reflect peak demands for Firm Transportation Service classes, the average of the measured daily demands during the system three-day peak in the test year for these classes were used to provide a peak related contribution. No interruptible sales or transportation demands were included in the development of the design day demand allocation.

Q. Why did you choose to utilize NW Natural's design day demand for the firm service classes rather than an actual peak day demand in the application of the P&A allocation method?

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

(1) A utility's gas system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred based on 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 NW Natural's design day demand best reflects the factors that actually cause costs to be incurred.

A. NW Natural must consistently rely upon design day demand in the design of its own transmission and distribution facilities required to serve its firm service customers. More importantly, design day demand directly measures the gas demand requirements of the utility's firm service customers which create the need for NW Natural to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. In my opinion, there is no better way to capture the true cost causative factors of NW Natural's operations than to utilize its 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, a utility'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 a utility'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.

B. Transmission, Storage and Distribution Plant

Q. How were Transmission Mains allocated in the COSS?

A. Transmission mains are functionalized as transmission plant and were allocated to the firm and interruptible sales and transportation classes under the P&A method described above.

Q. How were Storage plant assets allocated in the COSS?

A. Mist storage plant attributable to the utility operation provides the system with gas supply support during the heating season. Because of the seasonal nature of the service provided, the costs are allocated based on incremental seasonal load, which is the seasonal firm and interruptible sales load less the average non-seasonal load. The portion of the Company's two LNG facilities attributable to the Washington jurisdiction were allocated to the firm sales customers based on their contribution to the design day allocation factor.

Q. How were Distribution Mains allocated in the COSS?

A. Distribution mains were allocated to the firm and interruptible sales and transportation classes under the P&A method. A special study using Geographic Information System ("GIS") data was performed to determine the specific pipe size distribution main to which each of the Rate Schedule 41, Non-Residential Sales & Transport Service, and Rate Schedule 42, Large Volume Non-Residential Sales & Transport Service, were attached. For those customers in these classes that are attached to distribution mains of 4 inches diameter or greater, the respective customers' P&A load characteristics were only included in the allocation of that portion of the distribution mains investment of equal or greater pipe size than the 4-inch main. Interruptible sales and interruptible transportation customers only received the ***average*** portion of the P&A allocation. The remaining firm sales service classes received a full allocation of all distribution mains regardless of pipe size.

Q. Please describe the special studies conducted for purposes of allocating other distribution plant investment.

A. Regarding NW Natural's major plant accounts, current cost factors were developed to allocate the following FERC accounts: Services – Account No. 380, and Meters –

Account 381. These cost factors reflect differences in the current unit equipment and installation costs that particular customer groups cause the Company to incur. For example, the cost of a 1/2-inch plastic service line that could serve a residential customer costs less, on a per unit basis, than the cost of a 4-inch steel service line to serve a larger industrial customer. The average cost per service was compiled for current Residential, Commercial and Industrial service installations and then aggregated by rate class according to the categories of customer types.

The Company's 2017 assembly cost guide for meter installations, including construction overheads, was used to determine the cost by meter type, size and delivery pressure, which were then applied to the corresponding number of meters in service by rate class. The cost results were escalated to current dollars using the IHS Markit Ltd. construction cost index.

Q. What other noteworthy plant allocations have been made?

A. Miscellaneous Intangible Plant Accounts 303.1 – 303.4, were segregated into customer and plant related categories and allocated accordingly based on a review of the various computer software investment elements in each of the sub-accounts. The remaining intangible plant in Account 301 – Organizational Expense and Account 302 – Franchises and Consents, were allocated based on Storage, Transmission and Distribution Plant.

Q. Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.

A. These items were allocated by function in proportion to their associated plant accounts.

C. Transmission and Distribution Operation and Maintenance Expenses

Q. How did the COSS allocate transmission and distribution related operation and maintenance ("O&M") expenses?

A: In general, these expenses were allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of cost (*i.e.*, expenses by the utility to operate and maintain those facilities). As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 893, Meters and House Regulator Expenses, is allocated on the same basis as its corresponding plant accounts, Meters – Account 381 and House Regulators – Account 383. With the detailed analyses supporting the assignment or allocation of major plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

D. Customer Service and Administrative & General Expenses

Q. Please describe the costs included in customer service related O&M expenses and how these costs were treated in the COSS Study.

A. The category of customer related O&M expenses includes the following FERC accounts: Meter Reading – Account 902; Customer Records and Collections, including monthly billing postage and printing – Account 903; and Uncollectible Accounts – Account 904.

A "Meter to Cash" study was conducted by NW Natural in 2016 for customer service functions performed by responsibility centers including: meter reading, billing, payment processing, customer contact center, and credit & collections. Costs were compiled to establish costs-per-customer for Residential, Small Commercial and Industrial ("C&I"), and Large C&I customer groups based on an analysis of labor costs and expenses of personnel involved in the various customer service activities related to the respective customer groups. The unit costs were used to allocate the account balances in FERC Accounts 901, 902 and 903 according to the corresponding number of Residential, Small C&I and Large C&I customers by rate class. Uncollectible Accounts expenses (FERC Account 904) were assigned to the rate classes based on a three-year average of uncollectible account write-offs according to the corresponding number of Residential, Small C&I, and Large C&I customers by rate class.

Q How did the COSS allocate Administrative and General expenses?

A. Administrative and General ("A&G") expenses were allocated in relation to plant, O&M or labor expenses. Specifically, A&G expense Property Insurance – Account 924 was allocated based on storage, transmission and distribution plant, as were Rents – Account 931 and Maintenance of General Plant – Account 935. The following accounts were allocated based on NW Natural's labor expenses: A&G Salaries, Office Supplies and Expenses, and Transferred Administrative Expense – Accounts 921 and 922, Injuries and Damages – Account 925, and Pensions and Benefits – Account 926. Miscellaneous General Expense – Account 930 was allocated on O&M. This is a reasonable approach to allocating A&G expenses.

Q. How did the COSS allocate taxes other than income taxes?

A. The study allocated all taxes, except for income taxes, in a manner which reflected the specific cost associated with the particular tax expense category. Generally, taxes can be cost classified based on the tax assessment method established for each tax category (*i.e.*, payroll, property, or function). Typically, taxes of a utility other than income taxes can be grouped into the following categories: (1) labor; (2) plant; and (3) function, *e.g.*, Transmission, Distribution, Storage, etc. In the NW Natural COSS, all non-income taxes were assigned to one of the above stated categories which were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. How were income taxes allocated to each customer class?

A. Current income taxes were allocated based on each individual class' revenue requirement.

E. Gas Supply Planning, Management, and Gas Control O&M Expenses

Q. Please identify the costs included in gas supply and transportation related O&M expenses and how these costs were treated in the COSS?

A. The category of gas supply and transportation O&M expenses includes salaries and benefits of personnel in the following responsibility centers: Gas Acquisition & Pipeline Service (11150), Gas Accounting (42016), Mid-Office (42040), Gas Control (11300, and Major Account Services Team (11348). The corresponding labor-related expenses were distributed among the four customer categories: 1) firm sales, 2) interruptible sales, 3) firm transportation, and 4) interruptible transportation, based on a combination of the services provided and the time allocations reported by the personnel in these responsibility centers.

The Gas Acquisition & Pipeline Service function includes: gas supply procurement for sales customers; balancing of system supplies, including day-to-day storage activities; gas supply reporting, including commodity and closing price reporting; communication with transportation customers regarding delivery nominations; and the related labor expenses are recorded in FERC Account 870 and allocated based on reported time distributions between firm and interruptible sales and transportation customers.

The Gas Accounting function includes: Tracking and reporting of costs related to gas purchases, pipeline contracts, inventory and interstate storage and optimization activities; processing supplier invoices; and accounting and reporting of regulatory deferrals. The related labor expenses for this function are recorded in FERC Account 921 and allocated based on reported time distributions between firm and interruptible sales and transportation customers.

Mid-Office functions include: updating and maintaining North American Energy Standards Board ("NAESB") contracts; updating and maintaining International Swap Dealer Association ("ISDA") contracts; tracking and recording trade options for the U.S. Commodity Futures Trading Commission ("CFTC"); reviewing and confirming all physical and financial commodity transactions; assessing risk and price movement in the natural gas commodity market; and the related labor expenses are recorded in FERC Account 921 and are allocated based on system sendout.

The Major Account Services ("MAS") Team works with large customer accounts in the following capacities: customer acquisition, service election, and call center and billing. Call center and billing activities are charged to FERC Account 903 and include: addressing high bill complaints, which could include inspection of measuring equipment by industrial technicians; addressing any customer billing issues, including inquiries about rate structure; supporting credit and collection activities; producing bills for all MAS assigned accounts, including transportation and interruptible customers. Service election functions include: discussion with and implementation of rate options for large industrial and commercial customers while following internal approvals and processes, such as completing rate analyses and forms. These service election functions are charged to FERC Account 908. Customer acquisition functions are charged to FERC Account 908 and include: initiation and coordination of all new large customer acquisitions; completion of a margin agreement, service election form, and other relevant applications; management of curtailment activities and collection of pertinent information from the customer. The MAS related labor expenses are charged to FERC Accounts 903 (the billers and call center employees) and 908 (the Account Managers). The allocation of each function's labor was based on reported time distributions for services provided to Industrial firm and interruptible sales and transportation customers in Rate Schedules 41 and 42.

The Gas Control function entails the 24-hour daily monitoring and management of the flow of gas on the NW Natural pipeline system. This is accomplished by gas control personnel through electronic monitoring of various points on the system via SCADA and other electronic measurement equipment. The SCADA sites are located at town border stations throughout the NW Natural system. The labor expenses for this function are recorded in FERC Accounts 820 and 870; the allocation of which were based on system sendout to all sales and transportation customers, respectively.

F. NW Natural's Cost of Service Study Results

Q. Have you prepared a summary of NW Natural's COSS results?

A. Yes. Exh. RJA-2 summarized the results of NW Natural's COSS. The exhibit presents the resulting allocation by customer class of NW Natural's proposed revenue requirement based strictly on the results of the computations included in the COSS.

Q. Please compare the resulting COSS results to the current rates and associated non-gas revenues for each of NW Natural's customer classes.

A. Exh. RJA-2, page 2, line 47 presents the total COSS-based rate schedule revenue requirement for each of NW Natural's customer classes at the proposed system rate of return. Line 36, page 1, of this Exhibit presents Test Year margin revenues by customer class under NW Natural's current rates, net of gas costs. By comparing these two sets of revenues, one can see the extent to which NW Natural's current rates and non-gas revenues are reflective of COSS. The revenue-to-cost ratios on line 63, page 2, of this exhibit portray the relative difference between these two revenue amounts for each class. A revenue-to-cost ratio of less than 1.00 means that the current rates and revenues of the particular customer class are below its indicated COSS (*i.e.*, Schedule 1, Schedule 2 and Schedule 27), while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the customer class are above its indicated COSS (*i.e.*, Schedule 3, Schedule 41 and Schedule 42). These results provide cost guidelines for use in evaluating a utility's class revenue levels and rate structures. I will describe later in my testimony how these results were used to assign NW Natural's proposed revenue increase to its customer classes.

Q. Please describe the information presented in Exh. RJA-3.

A. The COSS summarized the costs allocated to the customer classes on a functionalized (*i.e.*, by storage, transmission, and distribution), and classified (*i.e.*, by demand, customer and commodity) basis. Of particular interest are the customer related costs. Exh. RJA-3 provides a summary of the functionalized and classified costs, and shows these on a unit cost basis. These results were used as a guide in developing the proposed monthly Customer Charge levels by tariff schedule, as discussed later in my testimony.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you have relied upon as the basis for NW Natural's rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

1. Efficiency;
2. Cost of Service;
3. Value of Service;
4. Stability;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of NW Natural.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed earlier, into practice and is particularly relevant for NW Natural because of the competitive supply alternatives that cap rates under its special contract.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal—rates should be equal and, where costs are different—rates should be different. In this case, this principle is an important requirement that supports NW Natural's proposed use of a single monthly Basic Service Charge for all customers within certain of its tariff schedules.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers can reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

In the case of a local distribution company ("LDC") such as NW Natural, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permit proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

A. Yes. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing

- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. *Capital Attraction* is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. *Consumer Rationing* requires that rates discourage wasteful use and promote all economically efficient use. *Fairness to Ratepayers* reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of retail gas rates?

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

1. System cost characteristics such as established in the COSS required by the WUTC, or embedded customer, demand, and commodity related costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and
4. Other considerations such as the value of service ceiling / marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact from modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must, in part, be influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate NW Natural's proposed revenue increase of $8.3 million to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for NW Natural's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of NW Natural's interclass revenue proposal?

A. Yes. Using NW Natural's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in consultation with NW Natural management personnel, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The first and benchmark option that I evaluated under NW Natural's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

The second option I considered was assigning the increase in revenues to NW Natural's customer classes based on an equal percentage basis of its current base (non-gas) revenues. By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class), there was no movement towards cost for most of NW Natural's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). While this option also was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop NW Natural's class revenue proposal.

Q. What was the result of this process?

A. After discussions with NW Natural, I concluded that the appropriate interclass revenue proposal would be one that reflects increases in revenues to certain rate classes, guided by the results of NW Natural's COSS, with increases to these rate classes moderated by establishing a maximum increase level above NW Natural's proposed overall increase in non-gas revenues of 2.50. This approach established a maximum margin revenue increase to any rate class of 50.20% (2.50 times 20.08%, the system average proposed increase to margin).

NW Natural's interclass revenue proposal includes an adjustment to the present revenue level in the Residential Sales Service class (Schedule 2), General Sales Service class (Schedule 1), and the Residential Heating Dry Out Service class (Schedule 27). In the case of these classes, the revenue adjustment insures their proposed rates will move class revenues closer to the COSS results for each class. Not only was the General Sales Service class and Residential Heating Dry Out Service class rates of return ("ROR") below unity (< 1.00 revenue-to-cost ratio) in the COSS results, they produced ***negative*** class rates of return at -3.35% and -6.75%, respectively.

The COSS results for the remaining customer classes, except for Residential Sales Service, indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this result would suggest the need for revenue decreases in order to move these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), the resulting customer impact implications for the Residential and General Sales Service classes has led me to conclude, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes. Rather, for this reason, revenue increases of less than the system average increase to margin of 20.08% have been made to the following non-residential classes: Basic Firm Sales Service Schedule 3 (of 18.07%), Non-

Residential Sales & Transport Service Schedule 41 (18.07%), and Large Volume Non-Residential Sales & Transport Service Schedule 42 (17.07%).

Q. Please summarize the benefits of this class revenue allocation approach.

A. This preferred inter-class revenue allocation approach resulted in reasonable movement of the class revenue-to-cost ratios towards unity or 1.00. That result is reflected in Exh. RJA-2 on Line 65 (page 2), wherein the revenue-to-cost ratios under the proposed class revenue increases are shown to converge – albeit modestly – towards unity or 1.00 compared to the parity ratios calculated under current rates (Line 64). In addition, the amounts of the existing rate subsidies among NW Natural's rate classes were reduced for those classes that were below parity under current rates. From a class cost of service standpoint this type of class movement, and reduction in class rate subsidies, is desirable.

VI. NW NATURAL'S RATE DESIGN PROPOSALS

Q. Please summarize the rate design changes NW Natural has proposed in this rate proceeding.

A. I will present the specific rate design changes and supporting rationale for NW Natural's proposals. NW Natural has proposed the following changes to the level of various charges its current rate schedules:

- For customers served under General Sales Service (Schedule 1), Residential Sales Service (Schedule 2), Basic Firm Sales Service (Schedule 3); and Residential Heating Dry Out Service (Schedule 27); NW Natural proposes to adjust the monthly Customer Charges to better reflect the underlying costs of providing basic customer service.

- Increase the Distribution Capacity Charge in the Large Volume Non-Residential Sales & Transportation Service (Schedule 42) to better reflect the underlying unit transmission and distribution demand costs associated with this customer class.
- Decrease the Storage Charge in the Large Volume Non-Residential Sales & Transportation Service (Schedule 42) to better match the underlying unit storage demand costs associated with this customer class.

Q. What are NW Natural's proposed increases to the Customer Charges for the aforementioned rate schedules?

A. NW Natural proposes to increase the Customer Charges for the General Sales Service (Schedule 1) to $7.00 from its current $3.47 level, and for Residential Sales Service (Schedule 2), to $9.00 from its current $7.00 level. At these proposed levels, the Customer Charge for these two classes of service will recover more of the monthly customer-related O&M (meter reading, billing and uncollectibles), and return of and on the meter and service line plant, as indicated by the COSS Study. The unit monthly customer cost in the Unit Cost page 3 of Exh. RJA-3 (line 16) is $23.74 for Schedule 1 and $23.70 for Schedule 2.

The Company proposes to increase the Customer Charge for the Residential Heating Dry Out Service (Schedule 27) to $9.00 from its current level of $6.00, which will bring this charge to approximately 28% of the full unit monthly customer cost of $31.90 for this rate class, as shown in Exh. RJA-3 (page 3, line 16).

The proposed Customer Charge for Basic Firm Sales Service (Schedule 3) is $22.00, an increase from its present level of $15.00. The $22.00 charge is approximately

51% of the full unit monthly customer cost of $43.45. The balance of the revenue increase proposed for Schedule 3 will be recovered by increases to the Schedule 3 Commercial and Industrial volumetric charges.

Q. Please describe the proposed changes to the volumetric charges for Non-Residential Sales & Transportation Service (Schedule 41).

A. Because the current fixed charges are set at an appropriate level in relation to the corresponding fixed costs, the revenue increase proposed for Schedule 41 will be recovered by increases to the Schedule 41 Commercial and Industrial volumetric charges. This proposal includes the equalization of the volumetric rates among these C&I customer groups.

Q. Please describe the proposed changes to demand charges for Large Volume Non-Residential Sales & Transportation Service (Schedule 42).

A. The Company is proposing to increase the Distribution Capacity Charge in Schedule 42 to $0.30078 from its current level of $0.15748, which will bring this charge to approximately 10% of the unit transmission and distribution demand cost per month for Schedule 42, per Exh. RJA-3 (page 3, lines 6 and 10). The current Storage Charge of $0.20415 in Schedule 42 is higher than the $0.19082 unit storage demand cost per month. Therefore, the Company is proposing to reduce this charge to the unit cost level of $0.19082, per Exh. RJA-3 (page 3, line 2). The net proposed revenue increase resulting from the changes to the demand charges will be recovered by revenue increases to the Schedule 42 Commercial and Industrial volumetric charges. The Company proposes to equalize the volumetric rates among these C&I customer groups.

Q. Have you provided an exhibit that depicts the proposed rates for all classes of service?

A. Yes. Exh. RJA-4 shows the derivation of each rate component for each of NW Natural's tariff schedules.

Q. Has a revenue proof been prepared to show that NW Natural's proposed rates generate the total distribution revenue and total revenue increase it has proposed in this proceeding (*i.e.* its total non-gas margin revenue)?

A. Yes. Exh. RJA-4 includes NW Natural's revenue proof for the Test Year.

VII. CUSTOMER BILL IMPACTS

Q. Please describe the bill impacts for residential customers under NW Natural's rate design proposal.

A. The monthly and annual bill impacts for a typical residential customer using 675 therms per year is shown on Exh. RJA-5. The average monthly increase for this residential Schedule 2 customer under the Company's proposed rate design (all else being equal) is $6.44, or about 13%. Monthly residential bill impacts over a range of usage for residential Schedule 1 and Schedule 2 customers are depicted on pages 1 and 3 of Exh. RJA-6, respectively.

Q. Have you prepared bill comparisons for NW Natural's other rate schedules?

A. Yes. Exh. RJA-6 also presents bill comparisons for NW Natural's other rate schedules where changes were made to the customer and volumetric charges, at varying monthly levels of gas usage. The exception is Schedule 42 because the changes to the average cost per therm of gas sold or transported for the customers served under Schedule 42 will uniquely vary based on the relationship of their level of monthly sales and transportation volumes to their individual contract demands. The higher the load factor experienced by the individual Schedule 42 customers, the lower will generally be their average cost per therm based on the rate design for this schedule.

Q. Does this conclude your direct testimony?

A. Yes.