Exh. RJA-1T

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	**DOCKET UG-260127**

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF RONALD J. AMEN

May 29, 2026

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ronald J. Amen, and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

Q. By whom are you employed, for how long, and in what capacity?

A. I am employed by Atrium Economics, LLC ("Atrium") as Chairman of the Board.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Cascade Natural Gas Company ("Cascade" or "Company").

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

A. I have over 40 years of experience in the utility industry, the last 27 years of which have been in the field of utility management and economic consulting. 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 and acquisition; 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 across North America 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 Exhibit RJA-2, which is the first exhibit to my testimony.

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

A. Yes.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. First, I present the load study analysis for purposes of determining each customer class's contribution to the system's peak load. Next, I present the development of the Company's allocated Cost of Service Study ("COSS") for the test year ended December 31, 2025, including a comprehensive overview of the schedules created in support of them. Finally, I present the Company's proposed rates and the resulting customer bill impacts based on the Company's requested revenue increase.

My testimony consists of the following topics:

- Load Study and Analysis
- Theoretical Principles of Cost Allocation
- Cascade's COSS
- A Summary of the COSS Results by Rate Class
- Determination of Proposed Class Revenues
- Rate Design
- Customer Bill Impacts
- Allocation of Gas Supply Demand Resources

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following Exhibits, all of which were prepared by me or under my supervision and direction:

- Exh. RJA-2 – Resume of Ronald J. Amen
- Exh. RJA-3 – Design Day Load Study
- Exh. RJA-4 – Cost of Service Study
- Exh. RJA-5 – Class Revenue Apportionment
- Exh. RJA-6 – Proposed Rate Design – May 1, 2027 and May 1, 2028
- Exh. RJA-7 – Customer Bill Impacts – May 1, 2027 and May 1, 2028
- Exh. RJA-8 – Gas Supply Resources Demand Allocations
- Exh. RJA-9HC – Cost of Service Study Results on Commission Template

III. LOAD STUDY AND ANALYSIS

Q. What is a load study?

A. A load study determines each customer class's contribution to the natural gas utility's pipeline system peak load. The objective of the Load Study is to quantify Design Day Peak ("Design Day") and attribute Design Day responsibility of individual rate schedule demands to system demands. This information is used to develop allocators for purposes of allocating shared costs, or costs that cannot be directly assigned, such as plant and equipment, operation, and maintenance (O&M") expenses, and some administrative costs to each customer class on the basis of peak day usage. Natural gas pipeline systems are designed and constructed to satisfy peak day demand under design weather conditions, and a load study identifies each class's relative contribution to the peak day demand. Once Cascade has performed its load study for all customer groups, Cascade will be able to assign service costs for individual customer classes based on the class contribution to the system peak.

Q. What are the Commission's rules related to load studies?

A. The Commission's cost of service study rules require all regulated utilities to file a COSS with its general rate case, and the COSS must be based on customer usage data from the best available source, which can include a load study. In particular, WAC 480-85-050 requires a COSS's data to meet certain characteristics for granularity, whether from meter reads or from a load study. Data from advanced metering technology (e.g., Automated Meter Reading ("AMR") or Advanced Metering Infrastructure) may be used in a COSS provided the data's granularity meets or exceeds the rule's requirements for hourly data for electric and daily data for natural gas.[1] When a utility has advanced metering technology that meets or exceeds the granularity requirement, the Commission expects the utility to use that data instead of using data from a load study.[2] Utilities without advanced metering technology must conduct a load study and use data from a load study in a COSS.[3] Data used in a load study cannot be older than five years under WAC 480-85-050.[4]

Q. Has Cascade developed a load study?

A. Yes. In the instant proceeding, Atrium has developed a Design Day Load Study ("Load Study"). Atrium's Load Study Report can be found at Exhibit RJA-3.

---

[1] *In re Amend. WAC 480-07-510 and Adopting Chapter 480-85 WAC Rel. to Cost of Serv. Studs. for Elec. & Nat. Gas Utils.,* Dockets UE-170002 and UG-170003, General Order R-59906 Order Amending and Adopting Rules Permanently ¶ 39 (Jul. 7, 2020).
[2] *Id.* ¶ 40.
[3] *Id.*
[4] *Id.* ¶ 40 n.9.

Q. Has Cascade acquired sufficiently granular customer usage data through either AMR or a load study in this filing?

A. Yes. The Company has dramatically expanded its daily metering capability through AMR. Table 1, below, shows the availability of daily metered data for the Residential (503), General Commercial (504), General Industrial (505), and Large Volume (511) classes for each of Cascade's four distinct weather zones.

Table 1 – Percent of Core Rate Classes with Daily Meter Readings – Dec. 31, 2025

	Daily Data as Percent of Total Meters			
	Residential CNGWA503	Commercial CNGWA504	Industrial CNGWA505	Large Volume CNGWA511
Yakima	48.06%	67.32%	65.66%	67.74%
Walla Walla	43.32%	64.75%	67.39%	72.22%
Bellingham	82.21%	84.32%	71.96%	85.19%
Bremerton	82.50%	88.45%	74.55%	71.43%

Q. Please describe the characteristics of Cascade's gas load.

A. Cascade serves customers throughout a geographically and economically diverse service territory. There are six primary rate classes: Residential Service (Tariff Schedule 503) or "Residential"; General Commercial Service (Tariff Schedule 504) or "Commercial"; General Industrial Service (Tariff Schedule 505) or "Industrial"; Large Volume General Service (Tariff Schedule 511) or "Large Volume"; Interruptible Service (Tariff Schedules 570) or "Interruptible"; Distribution System Transportation Service (Tariff Schedule 663) or "Transportation"; and Special Contracts (900 series). Rate classes 503, 504, 505 and 511 are considered to be "core"[5] and are specifically

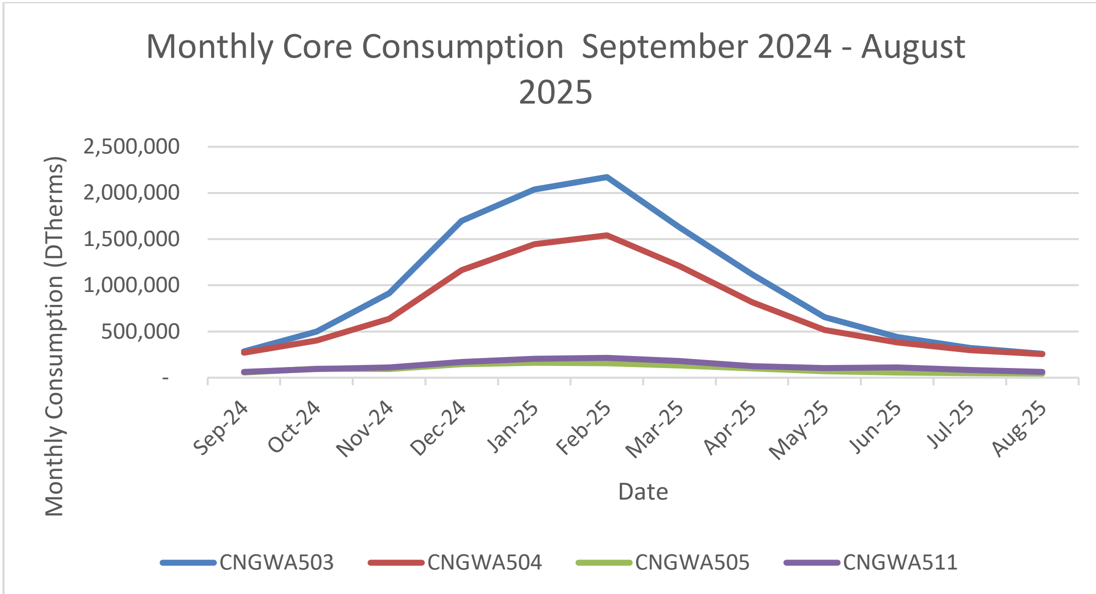
[5] "Core customers" are defined in the Cascade Washington 2025 IRP, as "Residential, firm industrial and commercial gas customers who require utility gas service." *In re Cascade Nat. Gas Corp. 2025 Integrated Res. Plan*, Docket UG-231023, 2025 Integrated Resource Plan at 12-4 (May 23, 2025).

included in Atrium's load study. The remaining classes, (Transportation (663), Special Contracts (900 series), and Interruptible (570)) are excluded from the load study. The Transportation (663) and Special Contracts (900 series) are excluded based on their specific designation as "non-core",[6] whereas Interruptible Service (570) is also excluded from the load study since this service could be interrupted under Design Day conditions. While Cascade's 2025 Integrated Resource Plan ("IRP") does not reflect peak demands for the Interruptible, Transportation, or Special Contracts classes, the average of the measured daily demands during the system three-day peak in the calendar years 2023-2025 for these classes was used to provide a peak-related contribution for these non-core customer classes.

Cascade's customers are spread across four diverse geographic areas with differing weather patterns and elevations (Bellingham, Bremerton, Walla Walla, and Yakima). Bellingham and Bremerton have generally moderate climates, with warm dry summers and wet semi-mild winters. They are comprised of an urban/suburban mix. Yakima and Walla Walla are semi-arid deserts and rural areas. Figure 1, below, shows total monthly consumption for each Core rate class for the twelve months ended August 31, 2025.

[6] "Non-core customers" are defined in the Cascade Washington 2025 IRP, as "Large customers who contract with a third party for supply and upstream pipeline capacity. Cascade provides distribution services only. Typical customers include large commercial, industrial, cogeneration, wholesale, and electric generation customers." *Id.* at 12-9.

Figure 1 – Cascade Monthly Consumption by Rate Class



Cascade's Residential (503) and General Service (504) customers are weather sensitive and are spread across all four weather zones. The Company's General Industrial Service (505) and Large Volume General (511) customers are also spread across all four weather zones and while weather sensitive, they are not as weather driven as the Residential and General Service classes.

Table 2 below provides a summary of premises and annual consumption projected for the test year ended 2025 as a percentage of Cascade's whole system throughput.

Table 2 – 2025 Test Year Premises and Consumption

Classes	Premises	% Premises	Test Year Consumption (Therms)	% Consumption
503 – Residential	207,163	87.89%	117,004,341	10.20%
504 – Commercial	27,728	11.76%	87,820,302	7.65%
505 – Industrial	488	0.21%	11,337,427	0.99%
511 – Large Volume	97	0.04%	16,093,119	1.40%
570 – Interruptible	6	0.00%	871,845	0.08%
663 – Transportation	208	0.09%	795,186,716	69.29%
900 – Special Contracts	7	0.00%	119,231,988	10.39%
TOTAL	**235,697**		**1,147,545,738**	

Q. How does the Company define its design day?

A. The Company's design day represents the coldest temperatures that can be expected to occur during an extreme cold or peak weather event. For distribution system planning purposes, Cascade relies on the deterministic coldest day in the 30-year history by weather zone. Atrium has adopted the peak by weather zone reflected in Cascade's most recent IRP for purposes of its Design Day Load Study. The Company uses a heating degree day ("HDD") as the unit of measure for temperature. HDD is calculated by taking the average temperature from a day and subtracting it from a reference temperature. If the reference temperature less HDD is negative, then the Company gives that day a 0 value for HDD. The Company uses 60°F as the reference temperature ("HDD 60"). The peak heating degree days used in the Load Study by weather zone are shown in Table 3.

Table 3 – Design Day HDD by Weather Zone[7]

	Bellingham	Bremerton	Walla Walla	Yakima
Design HDD	47	46	66	65

Q. Please describe the data Atrium used for developing the Load Study.

A. The data inputs for the Load Study included daily customer usage data, monthly billing data, system sendout data, customer counts, and weather data. Atrium relied on daily data sourced from deployed AMR meters, which served as the fundamental source of data for the Load Study. Cascade provided Atrium with daily HDD 60 data for the four Washington weather zones.

Q. Please describe the methodology and approach for developing the Load Study.

A. Prior to receiving the daily AMR dataset, Cascade reviewed the data and removed obvious irregular data, such as days with negative therms, or days where HDD 60 exceeded 10, but therms were zero. Atrium also removed data that was uncharacteristically high (i.e., a clear outlier, given HDD 60 and data trends for the respective rate class and weather zone). Once the obvious data irregularities were removed, Atrium performed regression analyses on the daily AMR dataset to identify each core rate class's load response to weather, measuring the historical linear relationship in each weather zone between daily metered volumes per customer, HDD 60. In addition to HDD 60, Atrium also measured the response for the change in HDD 60 from the previous day and included variables to capture load variations that were attributable to Friday, Saturday, Sunday, or holiday usage. Regressions were

[7] Docket UG-231023, 2025 Integrated Resource Plan at 8-6 (Figure 8-1).

performed on all available daily AMR data for the period from January 1, 2023, to February 28, 2026. The results of those regressions can be found in Exhibit RJA-3.

Atrium validated its regression model by back-casting load calculated using the daily regressions, against the actual daily therms in the daily AMR dataset, using actual HDD 60, the change in HDD 60 from the previous day, and variables to capture load variations that were attributable to Friday, Saturday, Sunday, or holiday usage, noting that the model closely predicted load and the model was an excellent representation of the daily AMR dataset. Atrium also extrapolated the daily regression-derived use-per-customer ("UPC") calculation to total monthly customers for each rate class and compared the results to monthly billing data. The daily regression results and additional information about Atrium's model validation process and comparisons to monthly billing data can be found in Exhibit RJA-3.

Q. What did you learn from the comparison of daily AMR data and monthly billing data?

A. Review of the AMR data demonstrated that the UPC per day derived from the daily AMR data differed from the expectations from the monthly billed data. For the Residential and Commercial customer classes (503 and 504), the variance was relatively uniform across the year whereas for the larger customer classes (505 and 511) the variance was not constant, demonstrating a greater variance in the winter months compared to the non-winter months, suggesting that the AMR data coverage for the 505 and 511 classes may not be sufficient to capture the load characteristics of the population; or the usage does not conform to a linear regression estimate, i.e., is not sufficiently heat sensitive. Consequently, Atrium has noted that the Daily AMR data would require adjustments to ensure that the resulting analysis using the AMR data did not underestimate the expected Design Day contribution from Classes 505 and 511. For this reason, Atrium determined that an analytical process was necessary to calibrate and adjust the AMR data to more closely agree to the monthly billing data and system sendout for the core customer classes.

Q. Please summarize the calibration adjustment Atrium performed to better align daily AMR data with monthly billing data and system sendout.

A. Atrium began with a baseline regression of monthly billing data regressed by HDD 60 and developed a benchmark Design Day prediction based on the monthly regression results. Because monthly billing data is comprised of multiple billing cycles, matching the correct HDD 60 with the monthly data is necessary. Atrium performed a lag analysis to determine the closest daily fit to monthly billing data by lagging daily regression-derived sendout estimates for all core rate classes, incrementally by 1 to 31, to determine which lagged period best matched (using the highest correlation) with monthly billing data. This lag was employed by lagging HDD 60 by the number of lagged days that produced the highest correlation, 19 days, for purposes of aligning daily and monthly therms and for aligning the correct HDD 60 with the monthly data for purposes of the monthly regressions.

The lagged daily therms were summarized by billing month and were compared to the actual monthly billing data. Atrium then calculated adjustment factors by summarizing and aligning daily AMR predicted therms via regression with monthly billing data therms, for each rate class and weather zone. Atrium then applied the adjustment factors to daily UPC in the AMR dataset. Atrium reran the daily regressions using the adjusted UPC rather than the UPC from the daily AMR dataset. The results of the adjusted daily regressions can be found in Exhibit RJA-3.

Though Atrium deemed it necessary to make a calibration adjustment to the AMR data prior to utilizing the AMR data for Design Day and class allocation, this should not deter the use of this data for the intended purpose within the Load Study. Rather, until a full AMR deployment and validation of the AMR data transmission and collection process, the Commission should ensure that both AMR data and billing data are considered to ensure that no undue shifts in cost allocation occur as a result of the migration towards AMR data.

Q. What were the predicted Design Day results for each of the Core Classes from your Adjusted Daily Regressions?

A. The Adjusted Daily Regression results were extrapolated to the total number of customers (as of December 31, 2025) for each weather zone and for each of the core classes. The Design Day prediction is shown in Table 4, below.

Table 4 – Design Day Prediction – Adjusted Daily

Rate	503	504	505	511	Total
Design Day	1,454,339	1,004,267	118,429	126,622	**2,703,657**
Core %	**53.8%**	**37.1%**	**4.4%**	**4.7%**	**100%**

The results are consistent with design day planning in the IRP and Atrium expects that as future AMR coverage increases, daily AMR data will become more precise in predicting sendout under peak weather conditions.

Q. How did you estimate the Design Day sendout for the non-core rate classes?

A. The peak demands utilized in the Cascade COSS are the respective Design Day demands for Cascade's firm sales classes, as developed in the Company's most recent

IRP. While the IRP does not reflect peak demands for the Interruptible Service, Distribution System Transportation Service, and Special Contracts classes, the average of the measured daily demands during the system three-day peak averaged over the last three years for these classes was used to provide a peak-related contribution for these non-core customer classes.

Q. Please provide the results for Cascade's total Design Day sendout.

A. The results of the Load Study and the resulting allocations *with* and *without* the inclusion of interruptible customers were prepared and summarized in Table 5, below.

Table 5 – Design Day Sendout (Daily Model) with and without Interruptible Classes

	Design Day Prediction – Daily (Adjusted)			
	Firm & Interruptible		*Firm only*	
Rate Class:	**Therms**	**%**	**Therms**	**%**
Residential (503)	1,454,339	24.2%	1,454,339	24.3%
General Commercial (504)	1,004,267	16.7%	1,004,267	16.8%
General Industrial (505)	118,429	2.0%	118,429	2.0%
Large Volume (511)	126,622	2.1%	126,622	2.1%
Interruptible (570)	5,190	0.1%		0.0%
Distribution System Transportation (663)	2,702,987	45.1%	2,702,987	45.1%
Special Contracts (900 series)	586,368	9.8%	586,368	9.8%
TOTAL	**5,998,202**		**5,993,012**	

IV. 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 customer classes. In this case, an embedded COSS is a useful tool for determining the allocation of Cascade's revenue requirement among its customer classes. It is also a valuable guide for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

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, are shared by customers who use the same facilities and the use by one class precludes the use by another class.

Utility costs may be fixed or variable in nature. Fixed costs do not change with the level of 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. Variable costs change directly with changes in throughput. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, many utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs are 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 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. What is the general approach used to develop a COSS?

A. Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (a historical period) or the estimated book value of costs for a forecasted test year or some combination of historical and future costs. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Q. Are COSSs an application of economic theory to cost allocation?

A. The allocation of costs using COSSs is not a theoretical economic exercise. Rather, it is 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 COSS 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 the incremental cost of providing service but is less than stand-alone costs. The logic for this concept is that if customers' prices exceed incremental cost, those customers contribute 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 stand-alone costs because the customer would not be willing to participate in the service offering if prices exceed stand-alone costs.

Stand-alone costs are an important concept for Cascade 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 stand-alone costs for some customers, prices must nevertheless be set below the stand-alone costs, 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 costs 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") 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 design day peak 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 manner in which such costs are defined and their subsequent allocation.

<u>*Customer*</u> 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 generally 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 of 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 a special study may be conducted, thereby providing further analysis 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.

V. STRUCTURE AND PROCESS STEPS OF THE COST OF SERVICE STUDY

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

A. In order to establish the cost responsibility of each customer class, the COSS consists of a three-step analysis process: (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost 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 gas supply, renewable natural gas (“RNG”) infrastructure, transmission, and distribution. The costs are functionalized in accordance with the Federal Energy Regulatory Commission (“FERC”) Uniform System of Accounts.

Q. Please describe cost classification.

A. The second step, classification of costs, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer (2) demand or capacity, and (3) commodity, along with an additional revenue classification consisting of working capital items and revenue.

Q. Please describe cost allocation.

A. 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 legislative and regulatory policies and evidentiary requirements applicable to the utility.

Q. Why are these considerations relevant to conducting Cascade'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, and in particular WAC chapter 480-85, which was adopted by the Commission in Docket UG-170003.[8]

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 to understand the potential influence of these characteristics on cost causation. 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. The physical configuration of the Cascade' 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 has been extracted from the Company's total cost of service

[8] Dockets UE-170002 and UG-170003, General Order R-59906 ¶ 83.

(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. Cascade maintains many detailed plant accounting records for its distribution-related facilities.

Q. How are Cascade's classes structured currently?

A. The COSS evaluated seven customer classes: Residential Service (Tariff Schedule 503); General Commercial Service (Tariff Schedule 504); General Industrial Service (Tariff Schedule 505); Large Volume General Service (Tariff Schedule 511); Interruptible Service (Tariff Schedule 570); Distribution System Transportation Service (Tariff Schedule 663); and Special Contracts.

Q. Do you propose any modifications to the current classes?

A. Yes.

Q. How are Cascade's classes structured for purposes of the proposed COSS?

A. As part of this proceeding, the Company is proposing revisions to certain customer class schedules to provide additional clarity within the tariff and to appropriately reflect the treatment of RNG costs within the COSS framework.

The Company considers RNG to be part of its broader carbon compliance strategy, and the RNG costs are currently recovered as a component of Cascade's Climate Commitment Act ("CCA") cost recovery mechanism. To ensure that customers subjected to the CCA are appropriately assigned RNG-related costs, the Company proposes separate customer schedules for customers that are exempt from the CCA. As discussed in the Direct Testimony of Jennifer G. Gross (Exhibit JGG-1T), the newly proposed Schedules 404, 405, 411, 470, and 463 are for customers who meet the exemption criteria in Schedule 700, Climate Commitment Act (CCA) Rate Adjustment ("Schedule 700") charges.

The proposed exempt customer schedules will separate CCA-exempt customers from customers subjected to the CCA, which the Company believes will provide additional transparency and clarity within the tariff structure. The proposed rate schedule changes also facilitate recovery of RNG-related costs through base rates within the tariff framework, rather than necessitating a separate recovery mechanism.

Accordingly, the proposed class structure supports the appropriate allocation and recovery of RNG-related costs while maintaining consistency with the Company's overall COSS framework.

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. Relevant here are the Commission's procedural rules for general rate case proceedings that require a natural gas utility to include in its rate case filing a COSS that complies with WAC chapter 480-85.

Q. Can you briefly describe the development of requirements in WAC chapter 480-85?

A. In its December 2016 Order in Dockets UE-160228 and UG-160229 (*consolidated*), the Commission 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.[9] This action by the Commission was followed by a Preproposal Statement of Inquiry (CR-101) on July 19, 2018, in Dockets UE-170002 and UG-170003. The statement initiated a rulemaking to streamline the submission and evaluation of cost of service studies by "developing an accurate, transparent, and effective method and process for parties to present cost of service studies in general rate proceedings[;]" standardizing presentations of cost of service studies and supporting information; and reducing the administrative burden on companies, intervenors, and the Commission.[10]

Q. What was the result of the Commission rulemaking proceeding?

A. For natural gas distribution mains, the Commission determined that a Demand Classification should be used:

> The Commission modifies the language in Table 4 of proposed WAC 480-85-060(3) regarding the natural gas distribution mains classification method to clarify the Commission's intent. The method was originally expressed as "system load factor," which for a utility is used to determine how to allocate between demand and throughput. When the system load factor is used in the context of classification, there is no mathematical difference between using simply "demand" as the classification and continuing to allocate costs based on the system load

[9] *Wash. Utils. & Transp. Comm'n v. Avista Corp., dba Avista Utils.*, Dockets UE-160228 and UG-160229, Order 06 Final Order Rejecting Tariff Filing ¶ 116 (Dec. 15, 2016).
[10] Dockets UE-170002 and UG-170003, Preproposal Statement of Inquiry (CR-101), WSR 18-16-005 (Jul. 19, 2018).

> factor. Cascade demonstrated this mathematical relationship in its comments and proposed that the wording be updated to clarify that the classification method for natural gas distribution mains should be "demand." We agree. Cascade's proposed clarification produces the mathematical result intended by the Commission, but more clearly applies cost of service principles. Accordingly, the Commission modifies the natural gas distribution mains classification method in Table 4 of proposed WAC 480-85-060(3) to read "Demand."[11]

For the allocation of natural gas distribution mains, the Commission included Design Day (peak) and annual throughput (average) as the components of the Peak & Average methodology.

> While the Commission has historically rejected design day methodologies, the Commission adopts design day in this rulemaking. The Commission sees value in allocating the costs of distribution mains according to the intended design of the system. A core cost of service principle iterates that customers who can be directly assigned responsibility for a utility's costs to serve them should also be responsible for recovery of a utility's appropriate costs. The selected method for the allocation of natural gas distribution mains recognizes that a single customer class should be directly assigned the costs of distribution mains when practical.[12]

Q. Is Cascade's COSS consistent with the rules in WAC chapter 480-85?

A. Yes.

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

[11] Dockets UE-170002 and UG-170003, General Order R-59906 ¶ 76.
[12] *Id.* ¶ 49.

average load is allocated on the basis of each class's 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's excess or unused demand.

The P&A methodology 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."

Q. Why is Cascade's design day demand used for the firm service classes better 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 on the basis of an average of peak demands.

(2) Design day demand is more consistent with the level of change in customer demand 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 Cascade's design day demand best reflects the factors that actually cause costs to be incurred.

A. Cascade 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 Cascade 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 Cascade's operations than to utilize its design peak day requirements within its COSSs.

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.

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

A. The detailed process description of Cascade's COSS analysis is presented in Exhibit RJA-4 (Cost of Service Study). The detailed process description of Cascade's COSS analysis is presented in Exhibit RJA-4 (Cost of Service Study). Exhibit RJA-4 provides a full scope of the COSS development process and the results. Exhibit RJA-4 provides a full scope of the COSS development process and the results.

Q. Please provide a general overview of the content of Exhibit 4.

A. Exhibit RJA-4 consists of three sections detailing the process of developing Cascade's COSS. The first section includes an introduction, the general purpose, and an overview of the Excel-based fully functional COSS model presented in this proceeding. The second section presents the COSS development process specific to the Company including Functionalization, Classification, and Allocation. The Allocation section specifically describes all internal and external allocation factors and development bases and processes used in the COSS. The third section depicts the results of the COSS, including revenue requirement apportionment, comparison of cost of service with revenues under present and proposed rates, and development of rate of return by customer class under present and proposed rates.

Q. Please describe the schedules included in Exhibit RJA-4.

A. The following is the list of Schedules included in Exhibit RJA-4:

- Schedule 1 – Summary of Cost of Service and Rate of Return under Present and Proposed Rates – a summary of the cost to serve as compared to revenues under present and proposed rates.

- Schedule 2 – Account Balances, Functionalization, Classification and Allocation – displays revenue requirements presented by FERC accounts with corresponding selections of functions, classifications, and allocations methods applied to the accounts.
- Schedule 3 – External Allocation Factors - depicts the derivation of external allocation factors that are explained in detail in Exhibit RJA-4.
- Schedule 4 – Internal Allocation Factors - depicts the derivation of internal allocation factors that are explained in detail in Exhibit RJA-4.
- Schedule 5 – Cost of Service Allocation Study Detail by Account – a detailed cost of service study presented by the FERC accounts for the individual rate classes.
- Schedule 6 – Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class - a summary of functionalized and classified rate base and revenue requirements along with unit costs derived by customer class.

VI. ALLOCATION OF TRANSMISSION AND DISTRIBUTION PLANT

Q. How were transmission mains allocated in the COSS?

A. Transmission mains were allocated to the firm and interruptible sales and transportation classes under the P&A method described above, after deducting the transmission mains investment that was directly assigned to the Special Contracts class.

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, after deducting the specific distribution mains investment that was directly assigned to the Special Contracts class. A special study was performed to determine the specific pipe size and type of intermediate pressure distribution main to which each of the customers in Interruptible Service (570) and Distribution Transportation Service (663) were attached. The respective customers' peak and average load characteristics were included in the allocation of that portion of the distribution mains investment for the tranches of mains of equal or greater pipe size than the main to which they were attached. The remaining firm sales service classes received a full allocation of all intermediate pressure mains regardless of pipe size or type. High pressure distribution mains were allocated to all classes, with the exception of the Special Contracts class, which received a direct assignment of these mains, as described earlier. Additionally, RNG-related high pressure distribution mains and plastic intermediate pressure 6-inch mains were included in the study. These facilities were functionalized as RNG, classified as commodity-related plant, and allocated using the throughput-exempt commodity allocator.

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

A. Special studies were performed for Cascade's major plant accounts. Current cost factors were developed to allocate the following FERC plant accounts: Services – Account 380; Meters – Account 381; and House Regulators – Account 383. 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 3/4-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.

Q. What other noteworthy plant allocations have been made?

A. Miscellaneous Intangible Plant – Account 303, was segregated into customers, plant, and throughput related categories and allocated accordingly based on a review of the investment elements in the account. For Industrial Measuring & Regulating ("M&R") Station Equipment – Account 385, an allocation of this plant to the various customer classes was facilitated by research of property records conducted by Cascade's Washington District Office personnel to identify specific equipment with individual customers. The remaining M&R equipment in Account 385 that could not be identified with individual customers were allocated to the classes based on the assignment of the identifiable M&R equipment costs. In addition, RNG plant was established for M&R Station Equipment General – Account 378 and Industrial M&R Station Equipment – Account 385 was allocated using the throughput-exempt commodity allocator.

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

A. The reserve for depreciation and depreciation expenses were allocated by FERC account in the same manner as their associated plant accounts.

VII. ALLOCATION OF TRANSMISSION AND DISTRIBUTION OPERATION AND MAINTENANCE EXPENSES

Q. How did the COSS allocate transmission and distribution related O&M expenses?

A: In general, these expenses were allocated on the basis of 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 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.

VIII. ALLOCATION OF CUSTOMER SERVICE, ADMINISTRATIVE AND GENERAL EXPENSES

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

A. This category of customer service related O&M expenses includes the following FERC accounts, involving the following Cascade Responsibility Centers: Customer Services (RC 4767100, RC 4767200); Credit and Collections (RC 4767000); Revenue Accounting (RC 4760700); Information Systems (RC 4767800); and the nine Washington Districts:

- Meter Reading – Account 902, expenses were assigned to core or non-core customer groups based on an analysis of labor costs of field personnel involved in meter reading activities related to the respective customer groups and then allocated on a customer basis;
- Customer Records and Collections, including monthly billing postage and printing – Account 903, expenses were allocated to all classes using a customer allocator;

- Uncollectible Accounts – Account 904, expenses were assigned to the classes on the basis of uncollectible account write-offs;
- Miscellaneous Customer Accounts Expenses – Account 905, expenses were allocated to all classes using a customer allocator;
- Customer Service and Information Expenses – Accounts 907 through 910, expenses were allocated to all customer classes using customer allocators based on the nature of the underlying costs; and
- Sales Expenses – Accounts 911 through 913, expenses were allocated to all classes using customer allocators.

Q How were Administrative and General ("A&G") expenses allocated to each gas customer class in the COSS?

A. A&G expenses were allocated in relation to plant, O&M, or labor expenses. A&G expenses allocated on the basis of transmission and distribution plant were:

- Property Insurance – Account 924,
- Rents – Account 931, and
- Maintenance of General Plant – Account 935.

The following accounts were allocated on the basis of Cascade's labor expenses:

- A&G Salaries – Account 920,
- Office Supplies and Expenses – Account 921,
- Outside Services – Account 923,
- Injuries and Damages – Account 925, and
- Pensions and Benefits – Account 926.

General Advertising Expenses – Account 930.1 was allocated on the basis of rate base. Miscellaneous General Expense – Account 930.2 was allocated on the basis of transmission and distribution 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 on the basis of the tax assessment method established for each tax category, i.e., payroll, property, or function. In the Cascade COSS, Gross Revenue Taxes were functionalized as distribution-related costs and allocated to customer classes based on revenue. Property, Payroll, and Miscellaneous Taxes were allocated based on plant and labor.

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

A. Deferred income taxes and investment tax credits were allocated on rate base, as were current income taxes.

IX. ALLOCATION OF GAS SUPPLY O&M COSTS

Q. How were gas supply related O&M expenses allocated to each gas customer class in the COSS?

A. This category of gas supply O&M expenses includes salaries and benefits of personnel in the following responsibility centers: Gas Supply Resource Planning, Gas Supply, Gas Control, and a management expense allocation from affiliate, Montana-Dakota Utilities. The corresponding labor expenses were distributed among the three categories of Gas Planning, Gas Supply and Gas Control based on the time allocations reported by the personnel in these responsibility centers.

The Gas Planning function includes monthly/seasonal/annual gas resource planning; supply resource modeling and optimization; market intelligence gathering and analysis; IRP development; and Canadian / U.S. pipeline and storage operational, tolls / tariffs, and shipper related activities. The expenses in Other Gas Supply Expenses – Account 813 charged to this function were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using a P&A allocator.

The Gas Supply function includes gas supply procurement for core customers; balancing of core system supplies, including day-to-day storage activities; gas supply reporting, including commodity and closing price reporting; processing supplier invoices; updating and maintaining North American Energy Standards Board contracts; and tracking import authorizations and North American Free Trade certificates. Types of activities relating to non-core customers include resolution of imbalances and communicating with non-core customers relating to imbalance “packing” or “drafting” that affects the overall system balance position. The expenses charged to this function in Account 813 were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using sales or transportation volumes, respectively.

Production/RNG expenses – Account 813 was established to separately identify RNG-related costs. These expenses were functionalized as RNG, classified as commodity-related costs, and allocated using the throughput-exempt commodity allocator.

The Gas Control function entails the 24-hour daily monitoring and management of the flow of gas on the Cascade pipeline system in Washington. This is accomplished by gas control personnel through electronic monitoring of various points on the system via supervisory control and data acquisition ("SCADA") and Metretek measurement equipment. The SCADA sites are located at town border stations throughout the Cascade system and at some Special Contract customer locations. Metretek monitoring equipment is located at non-core customer locations for classes 570, 663, and 900. The expenses charged to this function in Distribution Load Dispatching – Account 871 were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using sales or transportation volumes, respectively.

X. CASCADE'S COST OF SERVICE STUDY RESULTS

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

A. Yes. Table 6 below presents a summary of the results of the Company's COSS that can be reviewed in detail in Schedule 4 of Exhibit RJA-4. Table 6 below presents a summary of the results of the Company's COSS that can be reviewed in detail in Schedule 4 of Exhibit RJA-4. The COSS shows an overall revenue deficiency to the Company of $25.099 million.

Table 6 – Summary Results of the COSS for Provisional Year 1

Customer Classes	Current Revenues	Cost to Serve	Current Rate of Return	Class Revenue (Deficiency)/ Excess	Current Revenue to Cost Ratio	Current Parity Ratio
Res503	$ 83,512,146	$ 96,073,311	4.9%	(12,561,165)	0.87	0.99
GSC504/404	$ 49,136,421	$ 41,375,113	13.3%	7,761,308	1.19	1.35
GSI505/405	$ 4,015,834	$ 4,532,193	6.0%	(516,359)	0.89	1.01
GSLV511/411	$ 4,425,618	$ 4,770,462	7.1%	(344,844)	0.93	1.06
Interruptible570/470	$ 154,817	$ 146,950	10.0%	7,868	1.05	1.20
Transport663/463	$ 36,407,797	$ 55,160,418	1.4%	(18,752,621)	0.66	0.75
Spl Contracts	$ 2,410,393	$ 3,103,980	2.6%	(693,587)	0.78	0.88
Total System	**$ 180,063,026**	**$ 205,162,427**	**5.6%**	**$ (25,099,401)**	**0.88**	**1.00**

Table 6 presents the revenue deficiency/excess for each rate class, the class rate of return on net rate base at current rates, the revenue to cost ratio, and the associated parity ratio. The resulting allocation by customer class of Cascade's proposed revenue requirement is 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 Cascade's customer classes.

A. Exhibit RJA-4, Schedule 4 presents the total COSS-based rate schedule revenue requirement for each of Cascade's customer classes at the proposed system rate of return. Schedule 4 also presents Test Year margin revenues by customer class under Cascade's current rates, net of gas costs, other operating revenues, miscellaneous charges, and revenue taxes. By comparing these two sets of revenues, one can see the extent to which Cascade's current rates and non-gas revenues are reflective of COSS. The respective revenue-to-cost ratios 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., Customer Classes 503, 505/405, 511/411, 663/463 and Special Contracts), 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 (e.g., 504/404 and 570/470). 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 Cascade's proposed revenue increase to its customer classes.

XI. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you relied on as the basis for Cascade's rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature and were considered here. 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*.[13] Each of these principles plays an important role in analyzing the rate design proposals of Cascade.

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

---

[13] James C. Bonbright, Albert L. Danielsen, & David R. Kamerschen, *Principles of Public Utility Rates*, 382-84 (2d ed. Public Utilities Reports, Inc. 1988).

producers and 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 stand-alone costs, discussed earlier, into practice and is particularly relevant for Cascade because of the competitive supply alternatives that cap rates under its special contracts.

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 Cascade'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 that 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 are able to 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. 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 an LDC such as Cascade, 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 of 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 These conflicts are not present in this instance.

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:[14]

- 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 those established in the COSS required by the Commission, 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;

---

[14] *Id.* at 385.

3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and local distribution company 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 has to be, in part, influenced by judgmental evaluations.

XII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. **Please describe the approach generally followed to allocate Cascade's proposed revenue increase of $25.099 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 Cascade's customer classes.

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

A. Yes. Using Cascade'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 conjunction with Cascade personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The first benchmark option that I evaluated under Cascade'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 as to the impact on certain classes, it was decided that a more gradual approach than 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 Cascade'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 results (as measured by changes in the revenue-to-cost ratio for each customer class), there was no movement towards cost for most of Cascade'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 Cascade's class revenue proposal.

Q. What was the result of this process?

A. After further discussions with Cascade, I concluded that the appropriate interclass revenue proposal would consist of an adjustment to the present revenue level in Cascade's service classes, with the exception of the Special Contract class. Residential Service class (Tariff Schedule 503) received 1.24 times the 15.89 percent system average increase, a 19.76 percent increase. General Industrial Service (Tariff Schedules 505/405), and Large Volume General Service (Tariff Schedules 511/411), received a revenue increase of 1.26 times the system average increase, or a 20 percent increase. Distribution System Transportation Service (Tariff Schedules 663/463) received a revenue increase of 1.3 times the system average increase or 20.66 percent. The COSS results for the General Commercial Service (Tariff Schedules 504/404) and Interruptible Service (Tariff Schedules 570/470) indicate its revenue-to-cost ratio was above parity at current rates and proposed rates. While this would suggest the need for a revenue decrease in order to move this customer class closer to cost (i.e., convergence of the resulting revenue-to-cost ratio towards unity or 1.00), the resulting customer impact implications for the Residential Service class has led me to conclude, in consultation with the Company, to refrain from a revenue reduction for the General Commercial and Interruptible Service class. Therefore, these classes received a 5 percent increase, less than the 15.89 percent system average increase.

In summary, this preferred revenue allocation approach resulted in reasonable movement of all customer classes toward parity or 1.00. The results are reflected in Exhibit RJA-5, page 1. From a class cost of service standpoint, this type of class movement, and reduction in the existing class rate subsidies, is desirable. The $25.099 million total system revenue requirement form the basis for the design rates to be effective May 1, 2027.

XIII. CASCADE'S RATE DESIGN PROPOSAL EFFECTIVE MAY 1, 2027

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

A. Cascade is proposing the following rate design changes to its current tariff schedules:

- For customers served under Residential Service class (Tariff Schedule 503), General Commercial Service class (Tariff Schedules 504/404); General Industrial Service (Tariff Schedules 505/405); Large Volume General Service (Tariff Schedules 511/411); Interruptible Service (Tariff Schedules 570/470); and Distribution System Transportation Service (Tariff Schedules 663/463), Cascade proposes to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service.
- Increasing the Demand Rate in the Distribution System Transportation Service (Tariff Schedules 663/463) to better reflect the underlying unit demand costs associated with this customer class.

Q. How do the newly proposed exempt customer classes discussed above impact rate design in this proceeding?

A. As discussed above, proposed Schedules 404, 405, 411, 470, and 463 are for customers that are exempt from the CCA. As such, RNG costs would not be collected in their volumetric rates, and the exempt customers will only pay the non-RNG base rate that is recovered through the Basic Service Charge. The Basic Service Charge will be applied for both non-exempt and exempt customers in Rate Schedules 503, 504/404, 505/405, 511/411, 570/470, and 663/463. In addition, the same Contract Demand and System Balancing charges will apply to both non-exempt and exempt customers in Distribution System Transportation Service (Tariff Schedules 663/463).

For the Tariff Rate Schedules that have block rates, including Industrial Service (505/405), Large Volume General Service (511/411), Interruptible Service (570/470), and Distribution System Transportation Service (663/463), the RNG-related component was included within the first block of the non-exempt volumetric delivery charges.

Q. Please describe the changes to the monthly Basic Service Charge levels for Tariff Schedules 505/405, Schedules 511/411, and Schedules 570/470.

A. The proposed monthly Basic Service Charge for Schedules 505/405 is $165.00, an increase of $35.00, or 27 percent. The proposed monthly Basic Service Charge for Schedules 511/411 is $450.00, an increase of $100.00 or 29 percent. The proposed monthly Basic Service Charge for Schedules 570/470 is $600.00 from its current level of $400.00. These increases to the Basic Service Charges will provide significant improvement in the recovery of the fixed customer-related costs via fixed charges.

Q. Is Cascade proposing to increase the Basic Service Charge for any of the remaining tariff schedules?

A. Yes. Cascade proposes to increase the Basic Service Charges for the Residential Service Schedule 503 to $12.00 from its current $6.00 level, and the General Commercial Service Schedules 504/404 to $34.00 from its current $25.50 monthly charge level. At this level, the Basic Service 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.

Q. Please describe the proposed changes to the Distribution System Transportation Service (Tariff Schedules 663/463).

A. The Customer Service Charge in Tariff Schedule 663 will be increased under Cascade's proposal to $1,440.00 from the current level of $1,200.00. The current System Balancing Charge of $0.00110 per therm of gas transported will decrease to $0.0009. The revenue from the System Balancing Charge will be credited to the purchased gas adjustment ("PGA"), thus reimbursing sales customers for the use of a portion of the Jackson Prairie and Mist storage resources for balancing the net differences between the transportation customers' daily transportation deliveries and daily gas usage. The System Balancing charge was derived from a study of Cascade's net daily system imbalance activity over the past five years. The System Balancing Charge will also apply to the transported volumes for the Special Contract customers.

Finally, the current Contract Demand ("CD") Charge in Schedules 663/463 of $0.45 per CD therms per month will be raised to $0.60, which will recover approximately 37 percent of the unit demand-related costs for this customer class. All blocks of the volumetric Delivery Charge in Schedules 663/463 will be ratably increased to collect the remainder of the proposed revenue increase to this Tariff Schedule.

Q. Have you provided an exhibit that depicts the proposed rates for all classes of service effective May 1, 2027?

A. Yes. Exhibit RJA-6 shows the derivation of each rate component for each of Cascade's tariff schedules to be effective on May 1, 2027.

Q. What is the impact of the foregoing proposed increases to fixed charges on the recovery of Cascade's fixed delivery service costs?

A. The proposed increases to the various Basic Service Charges and the proposed $0.15 increase to the CD Charge in Schedules 663/463 will result in an overall increase of $25.5 million of fixed cost recovery in fixed charges or 40 percent of Cascade's total rate schedule generated non-gas revenue requirement, leaving 59 percent of Cascade's fixed transmission and distribution costs to be recovered via the volumetric Delivery Charges.

XIV. CASCADE'S RATE DESIGN PROPOSAL EFFECTIVE MAY 1, 2028

Q. Have you designed rates for the Multiyear Rate Plan ("MYRP") 2 to be effective May 1, 2028?

A. Yes. Please see Exhibit RJA-6. Cascade proposes to apportion the incremental revenue increase of $18.1 million for the MYRP2 in proportion to the respective class revenue requirements as presented on page 1 of Exhibit RJA-5. The addition of the $18.1 million revenue requirement from MYRP2 is the basis for the rates designed to be effective May 1, 2028. Summarized in Table 7, below, are the current rates by class followed by the MYRP1 rates effective May 1, 2027, and the MYRP2 rates effective May 1, 2028.

Q. Do the changes to the non-exempt and exempt class structure apply to rates proposed to be effective May 1, 2028?

A. Yes. The same principle will apply in MYRP2, such that RNG-related plant additions and associated RNG costs included in the provisional revenue requirement will only be collected from non-exempt customers, while the non-RNG provisional rate components will be recovered through the Basic Service Charge and, for Rate Schedules 663/463 only, Contract Demand and System Balancing charges.

Q. Are there additional proposed increases to the Basic Service Charges to be effective May 1, 2028?

A. Yes. As tabulated in Table 7, incremental increases to the Basic Service Charges in all rate schedules have been proposed, and a proposed $0.15 increase to the CD Charge in Schedules 663/463, which are supported by the Unit Cost Report in Exhibit RJA-4.

Table 7 – Current and Proposed Rates

Customer Class	Current Rate	Rate Effective May 1, 2027	Rate Effective May 1, 2028
Residential - 503			
Basic Service Charge	$6.00	$12.00	$15.00
Delivery Charge	$0.46712	$0.46305	$0.47323
Commercial - 504/404			
Basic Service Charge	$25.50	$34.00	$37.50
Delivery Charge - Non Exempt	$0.34826	$0.33933	$0.37308
Delivery Charge - Exempt	$0.34619	$0.33535	$0.35198
Industrial - 505/405			
Basic Service Charge	$130.00	$165.00	$180.00
Delivery Charge - Non-Exempt - first 500 therms	$0.26384	$0.33238	$0.47777
Delivery Charge - Non-Exempt - next 3,500 therms	$0.21880	$0.25411	$0.26014
Delivery Charge - Non-Exempt - over 4,000 therms	$0.21199	$0.24615	$0.25200
Delivery Charge - Exempt - first 500 therms	$0.26177	$0.30644	$0.34017
Delivery Charge - Exempt - next 3,500 therms	$0.21673	$0.25411	$0.26014
Delivery Charge - Exempt - over 4,000 therms	$0.20992	$0.24615	$0.25200
Large Volume - 511/411			
Basic Service Charge	$350.00	$450.00	$495.00
Delivery Charge - Non-Exempt - first 20,000 therms	$0.21650	$0.25952	$0.29721
Delivery Charge - Non-Exempt - next 80,000 therms	$0.17027	$0.19880	$0.20016
Delivery Charge - Non-Exempt - over 100,000 therms	$0.05592	$0.06530	$0.06575
Delivery Charge - Exempt - first 20,000 therms	$0.21443	$0.25269	$0.26097
Delivery Charge - Exempt - next 80,000 therms	$0.16820	$0.19880	$0.20016
Delivery Charge - Exempt - over 100,000 therms	$0.05385	$0.06530	$0.06575
Interruptible - 570/470			
Basic Service Charge	$400.00	$600.00	$660.00
Delivery Charge - Non-Exempt - first 30,000 therms	$0.12494	$0.11559	$0.13193
Delivery Charge - Non-Exempt - over 30,000 therms	$0.04826	$0.04290	$0.03971
Delivery Charge - Exempt - first 30,000 therms	$0.12287	$0.11075	$0.10623
Delivery Charge - Exempt - over 30,000 therms	$0.04619	$0.04290	$0.03971
Transport - 663/463			
Contract Demand	$0.45	$0.60	$0.65
System Balancing Charge	$0.00110	$0.00132	$0.00145
Basic Service Charge	$1,200.00	$1,440.00	$1,580.00
Delivery Charge - Non-Exempt - first 100,000 therms	$0.04736	$0.04976	$0.07339
Delivery Charge - Non-Exempt - next 200,000 therms	$0.02047	$0.01815	$0.01701
Delivery Charge - Non-Exempt - next 200,000 therms	$0.01441	$0.01180	$0.01106
Delivery Charge - Non-Exempt - over 500,000 therms	$0.00947	$0.00703	$0.00659
Delivery Charge - Exempt - first 100,000 therms	$0.04529	$0.04447	$0.04529
Delivery Charge - Exempt - next 200,000 therms	$0.01840	$0.01815	$0.01701
Delivery Charge - Exempt - next 200,000 therms	$0.01234	$0.01180	$0.01106
Delivery Charge - Exempt - over 500,000 therms	$0.00740	$0.00703	$0.00659

Q. Have revenue proofs been prepared to show that Cascade's proposed rates generate the respective total distribution revenue and total revenue increases to

be effective on May 1, 2027, and May 1, 2028, that it has proposed in this proceeding (i.e., its total non-gas revenue)?

A. Yes. Exhibit RJA-6 presents Cascade's revenue proofs for the respective total distribution revenue and total revenue increases to be effective on May 1, 2027, and May 1, 2028.

XV. CUSTOMER BILL IMPACTS

Q. Please describe the bill impacts for residential customers under Cascade's rate design proposal to be effective May 1, 2027.

A. The monthly and annual bill impacts for a typical residential customer using 600 therms per year are shown on page 1 of Exhibit RJA-7. The average monthly increase for this residential customer under the Company's proposed rate design is $5.80 or 6.61 percent. Monthly residential bill impacts over a range of usage are depicted on page 2 of Exhibit RJA-7.

Q. Have you prepared bill comparisons for Cascade's other non-residential tariff schedules under the rates effective May 1, 2027?

A. Yes. Exhibit RJA-7, pages 3-12, also present bill comparisons for Cascade's tariff schedules at varying monthly levels of gas usage, with the exception of Schedule 663. The average cost per therm of gas transported for the Schedule 663 customers will uniquely vary based on the relationship of their level of monthly transportation volumes to their individual contract demands; in other words, the higher the load factor experienced by the individual Schedule 663 customers, the lower will be their average cost per therm. The average monthly bill impact for Schedule 663 customers under Cascade's proposed changes to the rate components of the tariff schedule presented on pages 11-12 of Exhibit RJA-7.

Q. Have you prepared bill impacts for residential customers under Cascade's rate design proposal to be effective May 1, 2028?

A. Yes. The monthly and annual bill impacts for a typical residential customer using 600 therms per year is shown on page 1 of Exhibit RJA-7. The average monthly increase for this residential customer under the Company's proposed rate design is $3.51 or 3.75 percent. Monthly residential bill impacts over a range of usage are depicted on page 2 of Exhibit RJA-7.

Q. Have you prepared bill comparisons for Cascade's other non-residential tariff schedules?

A. Yes. Exhibit RJA-7, pages 3-12, also present bill comparisons for Cascade's tariff schedules at varying monthly levels of gas usage, with the exception of Schedule 663, as described above.

XVI. DETERMINATION OF ALLOCATED GAS RESOURCE DEMAND COSTS

Q. What is the purpose of this section of your testimony?

A. This section of my testimony describes the manner in which the Company plans for and utilizes the gas transportation and storage capacity that is needed to serve its natural gas customers. I will provide a recommendation as to the allocation of pipeline capacity and storage costs for use in Cascade's PGA filings.

Q. Please describe what drives Cascade's decisions regarding the use of pipeline capacity.

A. Most of Cascade's natural gas sales customers are firm customers as opposed to interruptible customers. Cascade's core market residential and small volume commercial and industrial customers expect and require the highest reliability of energy service, particularly during extremely cold weather. Demand for natural gas from Cascade's firm customers is at its highest during cold weather. However, the cold weather increases the demand of other interstate pipeline customers, thus reducing the availability of contracted but unused pipeline capacity.

Given Cascade's obligation to serve its firm customers, it is the expected customer demand, and in particular the shape of that demand, which drives Cascade to plan for and use pipeline capacity. As more fully described in the Company's 2025 IRP, Cascade must determine and achieve the needed degree of service reliability and attain it at the most reasonable lowest cost and least risk possible; that is, the least cost mix of available resources that can meet its design-day peak standard, while maintaining infrastructure that is sufficient for customer load. Often, due to lack of additional storage or other peaking resources, the only available incremental resource to ensure Cascade's ability to meet its Design Day standard is year-round pipeline capacity.

Q. How does Cascade determine its use of pipeline capacity?

A. The process for determining the need for pipeline capacity can be summarized in the six-step process described below. The six steps reflect a logical progression in identifying why and when capacity is needed and thus give guidance as to how to allocate the related costs.

Q. Please identify the steps and how they can guide pipeline capacity resource cost allocation.

A. **<u>Step 1:</u>** One must consider the average summer demand or sales volume level. This must be served by flowing gas supply using year-round pipeline capacity because, other than for load balancing, storage and peaking resources are not available in the summer.

Cascade's normalized average daily sales volume in the summer months during the 12 months ending December 2025 was approximately 35,898 dekatherms ("Dth")/day. Thus, average summer sales volumes require pipeline capacity of 35,898 Dth/day. Since this capacity is only available on a year-round basis and will be used to serve winter sales volumes as well (Step 2), it is reasonable to allocate the cost of this capacity to Annual Sales Volumes.

Step 2: In order to have sufficient volumes in storage to serve the winter sales volumes, storage injections must be made using flowing gas and year-round pipeline capacity. Average summer injection requirements and transactions for Jackson Prairie, Mist, and Plymouth LNG are 14,686 Dth/day. Cascade could schedule its injection requirements around its customer requirements and operate all summer long with 14,686 Dth/day of pipeline capacity. Because this capacity is needed specifically to fill storage, which is in turn used to serve winter sales volumes, it is reasonable to allocate the costs of this capacity to Winter Sales Volumes. This capacity is also available to flow additional gas to serve winter sales volumes after the summer injection period (Step 3).

Step 3: Before determining the need for additional pipeline capacity to serve winter demand, Cascade considers the average availability of storage withdrawals from Jackson Prairie that use Northwest Pipeline TF-2 capacity and thus do not require the use of year-round pipeline capacity. Average Daily winter withdrawals from Jackson Prairie storage average approximately 4,168 Dth/day. The TF-2 capacity utilized by Jackson Prairie withdrawals would reasonably be allocated partially to Winter Sales Volumes, Design Peak Volumes and, of course, system load balancing.

Step 4: Winter average daily sales volumes are 104,013 Dth/day. These requirements are met with the capacity acquired in Steps 1, 2, and 3, thus leaving an average winter sales demand of 49,261 Dth/day (104,013 minus 4,168 minus 14,686 minus 35,898) to be fulfilled with additional year-round pipeline capacity. It is reasonable to allocate the costs of this capacity to Winter Sales Volumes.

Step 5: Cascade considers its Design Peak Sales Requirement and the deliverability of all of its storage and peaking resources that have not already been considered in use on the average winter day. Cascade's estimated design peak requirement for the 12 months ending December 2025 was approximately 253,729 Dth/day (includes Company and transportation fuel use). Cascade's peaking and storage resources provide, at maximum deliverability, a total of 173,898 Dth/day (23,423 from Jackson Prairie (JP-1, 3, and 4), 71,070 from Mist and Jackson Prairie (JP-2), 69,405 from Plymouth LNG and 10,000 from Westcoast Direct). However, Cascade has already relied on 4,168 Dth/day from Jackson Prairie on an average winter day in Step 3, thus incremental storage and peaking provide a resource of 169,730 Dth/day (173,898 minus 4,168). It is reasonable that the costs of the various resources that provide this incremental deliverability should be allocated based on their use to serve the design peak requirements of the system.

Step 6: The design peak demand is not yet met, and no additional gas storage or peaking resources are available, including pipeline transportation. Cascade thus must use additional year-round pipeline capacity of 171,976 Dth/day (253,729 minus 35,898 minus 14,686 minus 49,261 minus 23,423 minus 69,405, plus an approximate reserve of 110,920 (25 percent)) to make up the shortfall. Because this last increment of pipeline capacity is required only to serve the design peak day requirements of the customer demand, it is reasonable to allocate the cost of this capacity based on the contribution of various customer classes to design peak day demand. Exhibit RJA-8, pages 2 and 3, illustrate the six steps described above in both tabular and graphical format, respectively.

Q. What is your overall recommendation as to the allocation of year-round pipeline capacity, storage, peaking, and redelivery capacity (TF-2) costs?

A. As summarized in the table on page 2 of Exhibit RJA-8, showing the six-step process, I recommend that year-round pipeline capacity costs should be allocated within the PGA as 13.2 percent to Annual Sales Volumes, 23.5 percent to Winter Sales Volumes and 63.3 percent to Design Peak Volumes. I recommend that the 80 percent of Jackson Prairie, its related TF-2 capacity, and Mist storage that is not allocated to system balancing be allocated in the PGA as follows: 11.5 percent to Winter Sales and 68.5 percent to Design Peak Day. Plymouth LNG, its related TF-2 capacity, and Westcoast Direct capacity should be allocated 100 percent to Design Peak Day.

Q. What are the resulting unit demand cost rates for the various sales service classes in the PGA?

A. The result of the computations to determine the class-by-class unit demand cost rates that result from the foregoing allocation of pipeline, storage and peaking capacity are shown on page 1 of Exhibit RJA-8.

XVII. CONCLUSION

Q. Does this conclude your Direct Testimony?

A. Yes.