NOTICE OF CONFIDENTIALITY
AN ATTACHMENT TO THIS TESTIMONY HAS BEEN FILED UNDER SEAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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IN THE MATTER OF ADVICE NO. 961-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE MARCH 7, 2020	**PROCEEDING NO. 20AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN W. WISHART

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

NOTICE OF CONFIDENTIALITY
AN ATTACHMENT TO THIS TESTIMONY HAS BEEN FILED UNDER SEAL

Confidential: Attachment SWW-1, Attachment SWW-2, Attachment SWW-5

February 5, 2020

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF ADVICE NO. 961-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE MARCH 7, 2020	**) PROCEEDING NO. 20AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN W. WISHART

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Public Attachment SWW-5	Revenue Proof
Attachment SWW-6	Proposed Tariffs Sponsored by Mr. Wishart – Redlined Version
Attachment SWW-7	Proposed Tariffs Sponsored by Mr. Wishart – Clean Version

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2011 Gas Phase II	Proceeding No. 11AL-151G
2016 HTY	The historical test year that establishes the revenue requirement in Proceeding No. 17AL-0363G
2019 Gas Phase II	Proceeding No. 19AL-0309G
CCOSS	Class Cost of Service Study
Commission	Colorado Public Utilities Commission
Firm Capacity Reservation Charge	Demand charge
FERC	Federal Energy Regulatory Commission
GAP	Gas Affordability Program
GRSA	General Rate Schedule Adjustment
MDQ	Maximum Daily Quantity
O&M	Operations and Maintenance
PSIA	Pipeline System Integrity Adjustment
Public Service or the Company	Public Service Company of Colorado
S&F	Service and Facilities
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF ADVICE NO. 961-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE MARCH 7, 2020	)	**PROCEEDING NO. 20AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN W. WISHART

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven W. Wishart. My business address is 1800 Larimer, Suite 1400, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as Manager of Pricing and Planning. XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy") and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Manager of Pricing and Planning, I am responsible for financial and policy analyses associated with the Company's electric, natural gas, and steam rates, in addition to the regular administration of the Company's electric, natural gas, and steam tariffs. My duties include quantitative analyses, cost allocation and rate design, and policy support on a number of state regulatory issues. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring the following attachments, which were prepared by me or under my direct supervision:[1]

- Confidential Attachment SWW-1 – Class Cost of Service Study ("CCOSS");
- Confidential Attachment SWW-2 – Rate Design;
- Attachment SWW-3 – Rate Comparison;
- Attachment SWW-4 – Bill Impact Analysis;
- Confidential Attachment SWW-5 – Revenue Proof;
- Attachment SWW-6 – Proposed Tariffs Sponsored by Mr. Wishart – Redlined Version; and
- Attachment SWW-7 – Proposed Tariffs Sponsored by Mr. Wishart – Clean Version.

[1] Portions of Attachments SWW-1, SWW-2, and SWW-5 reflecting the number and volumes of Interruptible Sales customers are confidential as there are fewer than fifteen customers in that class.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. As discussed in the Direct Testimony of Company witness Ms. Brooke A. Trammell, Public Service has filed a consolidated case, combining both a traditional Phase I, or revenue requirement phase, with a Phase II, or cost allocation and rate design phase. Accordingly, the Company requests that, as a result of this proceeding, base rates in its Gas Tariff are revised and implemented to recover the Company's revenue requirement established in this proceeding as opposed to establishing a General Rate Schedule Adjustment ("GRSA") and subsequently filing a Phase II. In my Direct Testimony, I provide support for and sponsor the Company's updated class cost of service study ("CCOSS") and resulting revenue distribution by customer class, which forms the basis for the Company's proposed base rates that I also sponsor. These base rates have been designed to recover the annual Gas department base rate revenue requirement of $644,483,385 established by Company witness Ms. Deborah A. Blair.

I begin by describing the principles of cost allocation and present the results of the CCOSS, which is Confidential Attachment SWW-1 to my Direct Testimony. I then review the total revenue distribution by customer class as a result of the Company's proposed class allocation methodologies. Next, I present the Company's rate design principles and discuss how they are related to natural gas rates. I also review Test Year sales volumes by rate schedule, which are the basis for the proposed natural gas rates.

This case is being filed prior to a final Commission decision in the Company's 2019 Gas Phase II, Proceeding No. 19AL-0309G (the "2019 Gas

Phase II"). At this time, the Administrative Law Judge ("ALJ") presiding over the proceeding has issued a recommended decision approving a comprehensive settlement in that matter, and has ordered that new rates and tariff changes go into effect on March 1, 2020, absent further action by the Commission. As a result, the rates, terms, and conditions currently in effect are likely to change in the near term, and it is appropriate to consider bill impacts and rate design in the context of the anticipated Phase II rates, as well as those currently in effect. In that context, in my Direct Testimony I discuss each of the Company's rate schedules and make recommendations regarding the design of each rate as shown on Confidential Attachment SWW-2, and also provide a rate comparison in Attachment SWW-3. I then provide estimated customer bill impacts, as reflected on Attachment SWW-4, and discuss the Revenue Proof reflected in Confidential Attachment SWW-5. Finally, I sponsor changes to the Company's Gas Tariff.[2] The redlined version of these tariff changes is included as Attachment SWW-6, and a clean version is included as Attachment SWW-7.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend that the Colorado Public Utilities Commission ("Commission"):

- Approve the Company's proposed functionalization, cost allocation, and revenue distribution by customer class resulting from the CCOSS;
- Approve the final rate design that I present in my Direct Testimony, and specifically authorize implementation of the proposed new base rates that I sponsor and support; and

[2] Company witness Mr. Steven P. Berman sponsors changes to the Company's Pipeline System Integrity Adjustment ("PSIA") tariff.

- Approve the Company's proposed tariff changes and authorize the Company to implement revised tariff sheets.

II. OVERVIEW OF CLASS COST ALLOCATION, RATE DESIGN AND BILL IMPACTS

Q. WHAT IS THE CONTEXT WITHIN WHICH THE COMPANY HAS UNDERTAKEN CLASS COST ALLOCATION, RATE DESIGN, AND PRESENTED BILL IMPACTS IN THIS FILING?

A. As I mentioned earlier, a comprehensive settlement was reached among all of the parties to the Company's recent Gas Phase II, and the ALJ issued a recommended decision approving the settlement, without material modification, on January 22, 2020.[3] Thus, absent further action by the Commission, the settled, and ALJ recommended rates ("Settled Rates"), will go into effect on March 1, 2020. Consideration of these anticipated new rates is particularly important in the context of my rate design discussion, as well as in the presentation of bill impacts. To provide a realistic view, due consideration is given to both the current rates as well as the proposed rates during the discussion of these principles in my Direct Testimony.

Q. PLEASE SUMMARIZE THE COMPANY'S APPROACH TO CLASS COST ALLOCATION AND RATE DESIGN IN THIS FILING.

A. The Company is following class cost allocation and rate design principles that are very similar to the methods used in our 2019 Gas Phase II, which utilized billing determinants and customer class data from calendar year 2016.[4] Allocation of

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[3] The parties to the 2019 Gas Phase II entered into a comprehensive Stipulation and Settlement Agreement ("Phase II Settlement" or "Settlement"). The Phase II Settlement has been recommended for approval by the ALJ's Decision No. R20-0046 ("Phase II Decision"), and will become a final order on February 12, 2020, with new base rates implemented on March 1, 2020, absent further action by the Commission.

[4] The Company recognizes that pursuant to the comprehensive Settlement, the Company's proposed CCOSS, settlement rates, and rate design were agreed to for purposes of settlement only, as further detailed therein.

costs among the customer classes is primarily based on each class's contribution to design day peak demand, total annual commodity volumes, and the number of customers in each class. Although the customer class characteristics, billing determinants and total revenue requirement by class have changed from the 2019 Gas Phase II, overall the relative revenue distribution among customer classes is very similar to that presented by the Company in that case, as shown on Table SWW-D-1 below.

Table SWW-D-1
Class Cost Allocation - 2019 Gas Phase II vs. Test Year

Customer Class	2019 Gas Phase II	Proposed TYE Sept 2020
Residential	65.4%	65.0%
Small Commercial	22.1%	22.1%
Large Commercial	10.9%	11.0%
Interruptible	1.4%	1.6%
Transportation Adder	0.3%	0.4%
Lighting	0.001%	0.001%
Total	100%	100%

Q. WHAT ARE THE HIGH LEVEL RESULTS OF THE CCOSS?

A. Table SWW-D-2, below, summarizes the results of the CCOSS. First, the Table shows the Test Year adjusted base rate revenue under the 2019 Gas Phase II rates (Column B) along with the rate of return for each customer class under those rates (Column C). This rate of return analysis in Column C shows that, in total, Public Service's gas department lags behind its authorized overall rate of return of 7.12 percent.

Table SWW-D-2 also shows the proposed revenue distribution by class after all customer classes have been moved to full cost of service (Column D).

Based upon the cost allocation in the CCOSS, this is the level of base rate revenue to be recovered annually by each customer class in order to recover the total base rate revenue requirement for Public Service's gas department as presented by Ms. Blair. Column E in the Table demonstrates that at full cost of service, each customer class achieves a rate of return of 7.33 percent, which is the system average rate of return, or weighted average cost of capital, requested in this proceeding.

Column F shows the resulting base rate revenue deficiency after comparing Test Year present revenue by class to each customer class's allocated base rate revenue requirement. These totals by class represent the increase in base rate revenue needed for each class to recover their total base rate revenue requirement. Column G shows this base rate revenue increase by class on a percentage basis.

Finally, Column H shows each class's percentage base rate increase relative to the system average increase. Proportionally, this shows which customer classes require an increase above the system average, or a decrease below the system average, in order to move to full cost of service.

TABLE SWW-D-2:
Proposed Base Rate Revenue Distribution by Class

	(A) Customer Class	(B) Adjusted Test Year Base Rate Revenue at Present Rates	(C) ROR at Present Rates	(D) Base Rate Revenue at Proposed Rates	(E) ROR at Proposed Rates	(F) Base Rate Revenue Deficiency at Proposed ROR	(G) % Base Rate Revenue Increase	(H) Relative Rate of Return
1	Residential	$328,234,889	2.66%	$418,714,591	7.33%	$90,479,702	27.57%	0.95
2	Small Commercial	$108,127,660	2.39%	$142,648,837	7.33%	$34,521,177	31.93%	1.11
3	Large Commercial	$55,067,039	1.79%	$70,681,822	7.33%	$15,614,783	28.36%	0.98
4	Interruptible	$7,076,514	1.16%	$10,105,766	7.33%	$3,029,252	42.81%	1.48
5	Transport Adder	$1,508,218	-NA-	$2,327,219	7.33%	$819,001	54.30%	1.88
6	Lighting	$4,945	-NA-	$5,162	7.33%	$217	4.39%	0.15
7	Total	$500,019,264	2.46%	$644,483,396	7.33%	$144,464,132	28.89%	1.00

Q. IS PUBLIC SERVICE PROPOSING ANY MODERATION IN THE DEVELOPMENT OF THE DISTRIBUTION OF THE PROPOSED BASE RATE REVENUE INCREASE BY CLASS?

A. No. As Table SWW-D-2 shows, the proposed base rate revenue increases for each class were distributed in a manner designed to move each class to the system average rate of return. Each class's cost-based revenue requirement is presented in the CCOSS.

Q. DO THE VARIATIONS IN THE BASE RATE INCREASE RELATIVE TO AVERAGE AMONG CLASSES REPRESENT VARIATIONS AMONG CLASSES BETWEEN RATE CASES?

A. Yes. The base rate increase relative to average by class, or relative rate of return, will vary to some extent between rate cases due to a variety of factors. For example, factors can include differences in the composition of costs between test years, variations in the composition of customers within classes, economic factors, non-normalized weather differences, and unusual events or circumstances that are not normalized that affect the Test Year.

Q. HAS THE COMPANY ANALYZED THE RESULTS OF THE CCOSS TO DETERMINE EXPLANATIONS FOR THE LARGEST VARIATIONS IN THE RESULTS AMONG CLASSES?

A. Yes. The Company identified factors that caused the interruptible and small commercial, as well as the Transportation Adder, to require the largest percentage base rate increase to produce the system average rate of return. These factors are addressed in Section III of my Direct Testimony.

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN METHODOLOGY UTILIZED IN THIS PROCEEDING.

A. The rate design methodology that was used to develop the proposed rates in this proceeding is also very similar to that used by the Company in the 2019 Gas Phase II. The Company is not modifying the basic rate structure for any gas rate schedules. The Company does propose that transportation customers be required to continue to contribute to the Gas Affordability Program ("GAP") through the Services & Facilities ("S&F") Charge, like all other customers, consistent with the Settled Rates. In general, the increases in monthly fixed charges are smaller than the increases in commodity or capacity charges. This is because demand-related costs, such as rate base for distribution mains and transmission pipes, have increased more than customer-related costs, such as meter costs and billing services. A comparison of the proposed rates to the settled rates recommended for approval by the Phase II Decision (previously defined as the "Settled Rates"), is found on Table SWW-D-3 below.

Table SWW-D-3
2019 Gas Phase II Settled Rates vs. Proposed Rates[5]

	2019 Phase II Settled Rates	Proposed Rates	Change
Residential (RG)			
Service and Facility Charge	$12.15/Month	$15.15/Month	25%
Usage Charge	$0.13268/therm	$0.17625/therm	33%
Small Commercial Sales (CSG)			
Service and Facility Charge	$43.58/Month	$55.58/Month	28%
Usage Charge	$0.11585/therm	$0.15798/therm	36%
Large Commercial Sales (CLG)			
Service and Facility Charge	$101.12/Month	$125.12/Month	24%
Capacity Charge	$8.73/Dth	$12.00/Dth	37%
Usage Charge	$0.23025/Dth	$0.34190/Dth	48%
SCHEDULE IG			
Service and Facility Charge	$41.00/Month	$50.00/Month	22%
On-Peak Demand Charge,	$8.73/Dth	$12.00/Dth	37%
Usage Charge,	$0.34760/Dth	$0.49680/Dth	43%
Small Firm Transport (TFS)			
Service and Facility Charge	$58.58/Month	$78.58/Month	34%
Usage Charge	$1.1585/Dth	$1.5798/Dth	36%
Large Firm Transport (TFL)			
Service and Facility Charge	$116.12/Month	$148.12/Month	28%
Firm Capacity Reservation	$8.73/Dth	$12.00/Dth	37%
Usage Charge	$0.2302/Dth	$0.3419/Dth	48%
Interruptible Transport (TI)			
Service and Facility Charge	$134.00/Month	$170.00/Month	27%
Usage Charge	$0.3539/Dth	$0.5058/Dth	43%

[5] The Service and Facility charges in this table include an incremental charge for the Company's Gas Affordability Program ("GAP") for all customer classes.

Q. WHAT ARE THE ESTIMATED AVERAGE MONTHLY BILL IMPACTS THAT RESULT FROM THE PROPOSED RATE DESIGN?[6]

A. The estimated monthly bill impacts, comparing Settled Rates to the proposed rates, are contained on Table SWW-D-4 below. As noted therein, the estimated bill impacts are smaller than the proposed changes to base rates. This is because base rates are only a portion of total monthly natural gas costs. The cost of the actual natural gas commodity is a large portion of customer bills and those costs are not being modified in this proceeding. In addition, as discussed by Ms. Blair in her Direct Testimony, part of the Company's proposal in this case is to transfer certain projects from the PSIA rider to base rate recovery, as well as to transfer the PSIA in base amount into the PSIA. As a result, the proposed base rate increase will be accompanied by a decrease in the PSIA rate. The current 2020 PSIA rate is 46 cents per dekatherm ("Dth"). At the same time base rates are changed on November 1, 2020 (as requested by the Company), the PSIA rate will be decreased to approximately 44 cents per Dth.[7]

Overall, the average monthly bill impacts range from 14.8 percent to 4.4 percent. The differences in bill impacts are primarily caused by the relative proportion of base rates to other charges, such as fuel, in customer bills. For example, base rates make up the largest portion of residential bills (51 percent) and, as a result, residential customers are expected to have the largest bill change

[6] These estimated monthly bill impacts were determined based on a comparison of the Settled Rates and the proposed rates.
[7] The new PSIA rates are reflected in the tariff sheets attached to the Company's Advice Letter in this proceeding, as well as in Attachments SWW-6 and SWW-7 to my Direct Testimony.

from the Settled Rates, estimated at 14.8 percent. By contrast, base rates only account for 12 percent of interruptible sales customers' bills. This is because interruptible service is a discounted service option for customers willing to accept periodic interruptions in their gas service. For interruptible sales customers, the expected bill impacts are only 4.4 percent.

Table SWW-D-4
Estimated Average Monthly Bill Impacts – Settled Rates to Proposed Rates

Rate Schedule	Average Monthly Bills		Change	
	2019 Phase II Settled Rates	Proposed Rates	$	%
Residential (RG)	$40.82	$46.88	$6.05	14.83%
Small Commercial (CSG)	$162.72	$186.78	$24.05	14.78%
Large Commercial (CLG)	$2,931.69	$3,275.06	$343.36	11.71%
Interruptible Sales (IG)	$10,446.80	$10,904.91	$458.11	4.39%
Small Firm Transportation (TFS)	$518.46	$590.98	$72.52	13.99%
Large Firm Transportation (TFL)	$4,420.17	$4,992.58	$572.41	12.95%
Interruptible Transportation (TI)	$25,111.45	$26,343.09	$1,231.64	4.90%

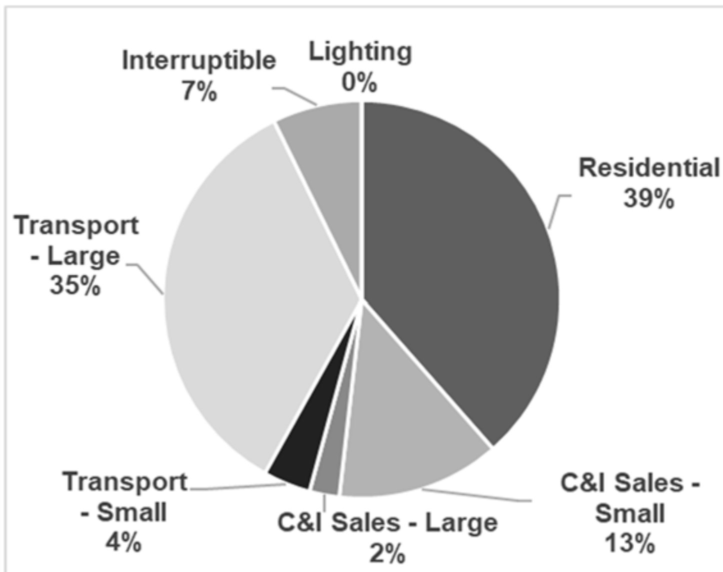
Q. WHAT IS THE BASIS FOR THE NATURAL GAS RATES THAT THE COMPANY IS PROPOSING IN THIS CASE?

A. As discussed by Ms. Trammell in her Direct Testimony, Public Service's test year in this proceeding is the twelve-month period ending September 30, 2020 ("Test Year"). The load data for this period consists of two months of actual weather normalized sales data and ten months of forecasted sales. Ms. Blair presents a cost of service study with a total base rate revenue requirement for the Public Service Gas Department of $644,483,385. For use in class cost allocation and base rate design, this amount is reduced by the amount of revenue received from fixed rate contracts. The adjusted revenue requirement is $631,497,686.

Q. WHAT SALES VOLUMES WERE USED FOR CLASS COST ALLOCATION AND RATE DESIGN?

A. I used sales volumes that are consistent with the data used by Company witness Debbie Blair for determining the Test Year base revenue. Figure SWW-D-1 below provides a summary of the Test Year commodity volumes by rate schedule.

Figure SWW-D-1
Test Year Volumes



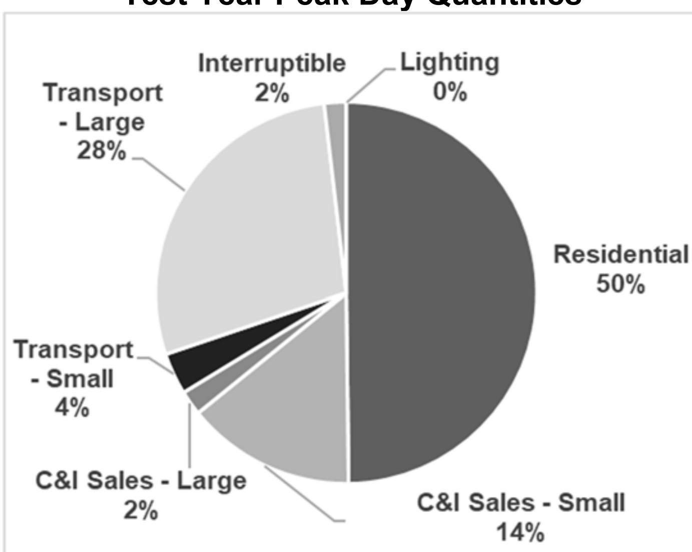
Q. DOES PUBLIC SERVICE SERVE AS A SUPPLIER TO ANY LOCAL DISTRIBUTION COMPANIES IN COLORADO?

A. Yes. The Company currently serves as a supplier to three Local Distribution Companies. These customers are included in the large transport category and typically account for about three percent of total annual sales volumes.

Q. HOW DO EACH OF THE RATE SCHEDULES CONTRIBUTE TO THE COMPANY'S MAXIMUM DAILY DEMAND?

A. As shown on Figure SWW-D-2 below, contribution to maximum daily demand varies by rate schedule. Residential customers are the largest contributors to the system's maximum daily demand. Their contribution to the system peak day is larger than their contribution to annual volumes because residential customers tend to use more natural gas during cold days. This is in contrast to other types of customers who may use gas more consistently throughout the year, such as those in the commercial or industrial sector.

Figure SWW-D-2
Test Year Peak Day Quantities



Q. WHAT WERE THE HIGH-LEVEL RESULTS OF THE CCOSS?

A. Table SWW-D-5 below shows the Test Year revenues that are expected to be collected from each customer class based on Settled Rates and compares those to the costs allocated to each class based on the results of the CCOSS model.

Table SWW-D-5
Proposed Base Rate Revenue Distribution by Class

Customer Class	Base Rate Revenue Based on 2019 Phase II	Proposed Class Cost Allocation	Base Rate Revenue Deficiency	Change In Base Rate Revenue
Residential	$328 Million	$419 Million	-$91 Million	28%
Small Commercial	$108 Million	$143 Million	-$35 Million	32%
Large Commercial	$56 Million	$71 Million	-$15 Million	27%
Interruptible	$7 Million	$10 Million	-$3 Million	44%
Transport Adder	$1.5 Million	$2.3 Million	-$0.8 Million	54%
Lighting	$0.0049 Million	$0.0052 Million	-$0.0002 Million	4%
Total	$500 Million	$644 Million	-$144 Million	29%

Q. HAS THE COMPANY ANALYZED THE DRIVERS OF THE BASE RATE REVENUE DEFICIENCY BY CUSTOMER CLASS?

A. Yes. As explained by Company witnesses Mr. Luke A. Litteken and Mr. Sridhar Koneru, the Company has implemented a new software system to support the customers using firm transportation service on our system. The costs of that new software are the cause of the 54 percent increase in the revenues associated with the transportation adder, which is applicable to all Transportation customers. The Small Commercial class has the smallest percentage increase in allocated costs. This is due to an improvement in that class's average load factor. While total Small Commercial sales have increased by 5.8 percent since the 2016 HTY used as the foundation for the 2019 Gas Phase II, the design day peak volumes for the class have decreased by 1.2 percent. That means that the Small Commercial class received a relatively smaller allocation of demand-related costs.

Residential base rate revenues are proposed to change by 28 percent relative to the overall change of 29 percent. This implies that the changes in the residential loads since the 2019 Gas Phase II case are very close to the overall changes in system load.

III. CLASS COST ALLOCATION

Q. WHAT ARE THE PRINCIPALS OF CLASS COST ALLOCATION USED BY PUBLIC SERVICE?

A. The Company's goal in allocating total system costs among individual customer classes is to assign a fair cost of service to each customer class based upon the costs they cause to be incurred (i.e., cost causation). The cost assignment is largely reflective of how the customers' loads drive costs on the Public Service system. For purposes of cost allocation in the CCOSS, the Company identifies six broad classes of customers, some of which consist of more than one rate schedule.

1. Residential (includes Residential Gas Service);
2. Combined Gas Lighting (includes Residential Gas Outdoor Lighting Service and Commercial Gas Outdoor Lighting Service);
3. Small General (includes Commercial – Small Gas Service and Firm Gas Transportation Service – Small);
4. Large General (includes Commercial – Large Gas Service and Firm Gas Transportation Service – Large);
5. Interruptible Sales (includes Interruptible Industrial Gas Service Sales); and
6. Interruptible Transport (Interruptible Gas Transportation Service).

Also identified in the CCOSS are costs specifically associated with serving transportation customers, which results in the direct assignment of costs to the transportation rate schedules. These direct assigned costs are expenses associated with customer service for transportation customers and recovery of these costs are assessed as an additional fixed monthly charge on their bills.

Q. PLEASE DESCRIBE THE PROCESS OF PREPARING A CLASS COST OF SERVICE STUDY.

A. The Company's CCOSS apportions total costs to the various customer classes in a manner consistent with cost causation as well as the way in which the Company operates its integrated natural gas system and provides service to customers. The process of conducting a CCOSS involves four steps: functionalization, classification, direct assignment, and allocation of costs. The result is a revenue distribution by customer class that is the target annual revenue to be collected through each class's rate design.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION OF COSTS.

A. Functionalization entails the sorting of plant investment and expenses by system component, such as production, transmission, distribution, or customer operations and generally follows the accounting categories defined in the Federal Energy Regulatory Commission ("FERC") uniform system of accounts. For example, FERC Account 367, Mains is a functional FERC account in which the Company's investment in transmission system mains is recorded. Therefore, in the CCOSS, this investment is functionalized as transmission, consistent with the FERC accounting instructions.

Q. PLEASE SUMMARIZE THE CLASSIFICATION OF COSTS.

A. Classification takes the functionalization step beyond the accounting records by identifying the primary driver of each cost. Here, I am referring to three basic types of costs: (1) commodity or volumetric-related costs incurred to procure gas that customers require during the Test Year (Commodity Classification); (2) capacity-related costs incurred to ensure reliable service during periods when system load is at its highest (Demand Classification); and (3) customer-related costs incurred to connect customers to the system, bill them, and administer their service on an ongoing basis (Customer Classification). I describe the classification process in more detail below.

Q. PLEASE EXPLAIN DIRECT COST ASSIGNMENT.

A. Not all costs are allocated in the CCOSS. Instead of allocation, a cost is directly assigned if it can be specifically linked to a specific customer class or individual customer. An example of direct assignment is the assignment of certain transportation-related costs to the transportation customer classes that I described earlier in my Direct Testimony.

Q. PLEASE SUMMARIZE THE PROCESS OF ALLOCATING COSTS AMONG CUSTOMER CLASSES.

A. The allocation step involves the assignment of classified costs to the various customer classes based upon cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. For example, service lateral costs are allocated to various customer classes based on service lateral replacement costs, weighted by the number of customers for each type of service lateral the Company installs. Again, wherever possible, costs are directly assigned to the customer class that causes the costs to be incurred. I provide more detail regarding the allocation process in this proceeding below.

Q. EARLIER YOU DESCRIBED THREE TYPES OF COST CLASSIFICATIONS. CAN YOU PROVIDE EXAMPLES OF COSTS THAT ARE UNDER THE COMMODITY CLASSIFICATION?

A. Yes. Commodity costs vary with the amount of natural gas the Company delivers, i.e., these costs increase or decrease as more or less gas is consumed. They are often referred to as variable or usage-related costs. Non-capital production and gathering costs, as well as product extraction costs, are typical commodity costs.

Q. PLEASE PROVIDE EXAMPLES OF COSTS THAT ARE CONSIDERED CAPACITY-RELATED, THUS FALLING UNDER THE DEMAND CLASSIFICATION.

A. Capacity-related costs are incurred by the Company to provide and maintain the facilities needed to meet the maximum load on the gas system. They generally do not vary with the number of customers or annual customer usage but rather vary with the quantity or size of plant and equipment. Capital costs associated with production, transmission, and storage plant as well as their related expenses are examples of the types of costs that are used to meet peak demand or capacity.

Q. FINALLY, PLEASE PROVIDE EXAMPLES OF COSTS THAT FALL UNDER THE CUSTOMER CLASSIFICATION.

A. Customer-related costs are the fixed costs associated with customer facilities such as service laterals and meters, along with expenses that vary with the number of customers but are independent of whether a customer consumes gas or not – such as meter-reading, billing, and postage costs. Customer costs, or a portion of these customer costs, are recovered through a monthly fixed charge.

Q. HOW DOES PUBLIC SERVICE CLASSIFY THE VARIOUS CATEGORIES OF FUNCTIONALIZED COSTS?

A. Public Service has followed the same guidelines for classifying functionalized costs over the past several Phase II proceedings. The following table illustrates the plant classification of the larger cost functions, as contained in the CCOSS:

Table SWW-D-6
CCOSS Rate Base Classification

Cost Function	Classification
Production and Gathering	Commodity
Product Extraction	Commodity
Underground Storage	Demand
Transmission	Demand
Distribution Mains	Demand
Meters	Customer
Regulators	Customer
Service Laterals	Customer
Common, General, and Intangible	Combination of Commodity, Demand, and Customer

Q. HOW MUCH OF PUBLIC SERVICE'S RATE BASE FALLS WITHIN EACH OF THE COST CLASSIFICATIONS?

A. Based upon the functionalization in the CCOSS, portions of rate base have been classified as either Commodity, Demand, or Customer. The resulting percentages of rate base assigned to each classification are reflected in Table SWW-D-7 below:

Table SWW-D-7
Percentages of Rate Base Assigned to CCOSS Classifications

Classification	Total Rate Base	Percentage
Commodity	$45 Million	2%
Demand	$1,389 Million	62%
Customer	$802 Million	36%
Total:	$2,236 Million	100%

Q. ARE THE COMPANY'S OPERATIONS AND MAINTENANCE ("O&M") EXPENSES ALSO CLASSIFIED FOR THE CCOSS?

A. Yes. The classification of O&M expenses follows the same process used for rate base classification and generally the classification of O&M expenses follows the classification of the plant investment it is related to. The following Table SWW-D-7 illustrates how the CCOSS classifies O&M expenses as Commodity, Demand, or Customer Classifications.

Table SWW-D-8
Percentages of O&M Assigned to CCOSS Classifications

Classification	O&M	Percentage
Commodity	$5 Million	2%
Demand	$152 Million	64%
Customer	$81 Million	34%
Total:	$238 Million	100%

Q. HOW DID PUBLIC SERVICE DEVELOP ALLOCATION FACTORS TO DETERMINE THE COST RESPONSIBILITY OF EACH CUSTOMER CLASS?

A. After directly assigning appropriate costs, the Company developed allocation factors to determine the cost responsibility of each class. The goal in developing any allocation factor is to reflect accurately how and why a specific cost was incurred. For example, if a certain portion of the distribution system was designed and sized to meet the anticipated peak load on the system, then that cost should be allocated among customer classes based on some measure of each class's contribution to system peak demand.

Examples of external allocation factors are class contribution to design day demand, annual class throughput, and the weighted or unweighted number of customers in a class. Other allocation factors were developed internally within the CCOSS based on the ratio of costs by customer class allocated using these external allocation factors.

Q. WHAT IS THE COMPANY'S PROCESS FOR ALLOCATING THE COSTS THAT WERE CLASSIFIED AS COMMODITY?

A. Costs classified as Commodity are allocated among customer classes based on the weather-normalized volumes for the Test Year.

Q. HOW DOES PUBLIC SERVICE CALCULATE CLASS ALLOCATION FACTORS FOR COSTS CLASSIFIED AS DEMAND-RELATED?

A. In general, the Company used the design day as its measure of peak demand.[8] The design day contributions of the Rate Schedule RG and CSG customers were determined using peak load information and linear regression techniques. The allocation factors for the remaining classes[9] were derived as follows:

- Rate Schedules TFS, TFL, and CLG: The sum of the individual customers' peak day quantities.
- Rate Schedules IG and TI: The peak demand of the class derived by applying an imputed 100 percent load factor to the Test Year sales volume.

[8] The design day was separately developed by the Gas Resource Planning Group.
[9] The gas lighting rate schedules, Rate schedules RGL and CGL, are not subject to cost allocation as the gas lighting services are not metered services.

Q. WHY DOES THE COMPANY CONTINUE TO SUPPORT LINKING THE ALLOCATION FACTORS FOR RATE SCHEDULES RG AND CSG TO DESIGN DAY REQUIREMENTS INSTEAD OF ACTUAL PEAK DAY REQUIREMENTS?

A. The purpose of a CCOSS is to classify and allocate costs based on why the costs were incurred. While a peak day is the actual usage for a specific day, design day also incorporates seasonal, historical, and other trends in the data to identify potential maximum usage that may be higher than recent peak usages. Specifically, the Company has designed its system to meet potential peak loads during a very cold day, or stretch of cold days, which ensures system reliability under extreme conditions. Furthermore, while class use during actual peak days is useful for determining each class's respective contributions to design day requirements, the capacity design of the system is based on design day requirements themselves to determine how much system capacity is needed to ensure reliable service. Consequently, the Company's capacity-related costs vary with its design day requirements and linking the allocation factors to design day requirements best reflects cost causation on the Company's system.

Q. WHAT IS THE COMPANY'S PROCESS FOR ALLOCATING THE COSTS CLASSIFIED AS CUSTOMER-RELATED COSTS?

A. Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics. For example, for meters, regulators, and service lateral costs, the cost of each type of new meter installation was used to determine the allocated investment.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S CCOSS?

A. I have included the Company's CCOSS as Confidential Attachment SWW-1 to my Direct Testimony. As a result of the increased revenue requirement proposed in this case, the costs allocated to each customer class have increased. Costs allocated to interruptible customers had the largest increase. This result is primarily driven by a nine percent growth in that customer class since the Company's last Phase II proceeding, resulting in an increased allocation of customer, commodity, and demand-related costs in the CCOSS. Table SWW-D-9 summarizes the results of the CCOSS and compares those results to the class cost allocation presented in the Company's 2019 Gas Phase II.

Table SWW-D-9
Changes in Class Cost Allocation

	2019 Phase II 2016 HTY	Proposed Cost	Change	
Residential				
Customer	$144,205,069	$177,386,408	$33,181,339	23.0%
Commodity	$4,273,808	$4,832,564	$558,756	13.1%
Demand	$161,156,369	$236,495,619	$75,339,250	46.7%
Total	$309,635,246	$418,714,591	$109,079,345	35.2%
Small General				
Customer	$42,984,344	$55,428,372	$12,444,028	29.0%
Commodity	$1,898,425	$2,189,417	$290,992	15.3%
Demand	$59,725,471	$85,031,048	$25,305,577	42.4%
Total	$104,608,240	$142,648,837	$38,040,597	36.4%
Large General				
Customer	$2,764,907	$3,591,677	$826,770	29.9%
Commodity	$3,172,550	$4,905,044	$1,732,494	54.6%
Demand	$45,648,269	$62,185,102	$16,536,833	36.2%
Total	$51,585,726	$70,681,822	$19,096,096	37.0%
Interruptible				
Customer	$257,601	$290,633	$33,032	12.8%
Commodity	$809,089	$970,871	$161,782	20.0%
Demand	$5,511,623	$8,844,262	$3,332,639	60.5%
Total	$6,578,313	$10,105,766	$3,527,453	53.6%
Lighting	$5,751	$5,162	($590)	-10.3%
Transportation Adder	$1,358,564	$2,327,219	$968,655	71.3%
Total	$473,771,840	$644,483,385	$170,711,545	36.0%

Q. WHY WAS THE COST ALLOCATION INCREASE TO THE RESIDENTIAL CLASS SMALLER THAN THE OTHER CLASSES?

A. The residential class had relatively slower growth since the 2016 HTY, since 2016 sales to the residential class have increased only 5.8 percent. More importantly, over that same period the class's contribution to the system design day peak demand increased only two percent. This implies that the load factor for the residential class has improved. Improvements in residential load factors can be driven by lower peak demand or by higher usage in off-peak periods, or both. The

Test Year data indicates that the average residential customer has reduced their design day peak demand, as a result of improvements in home efficiency that require less heating on particularly cold days. Company witness Jannell Marks further discusses declining use per customer for residential customers.

Q. WHY DID THE COMMODITY-RELATED COSTS ALLOCATED TO THE LARGE GENERAL CLASS INCREASE MORE THAT OTHER COST ALLOCATIONS?

A. While the percentage increase in commodity-related costs for Large General customers is large, the overall dollar impact is relatively small due to the small amount of costs that are classified as commodity-related. I investigated the cause of the percentage increase in commodity-related costs allocated to the Large General class and found that in the Company's 2019 Gas Phase II CCOSS, there were sales volumes associated with the Large General class that were inadvertently omitted from the cost allocation analysis. Correcting for this increased the commodity volume for large commercial customers and consequently the allocation of commodity-related costs.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS REGARDING THE CLASS COST ALLOCATION ANALYSIS?

A. The costs allocated to each rate class have increased as a result of the increase in the total base rate revenue requirement identified in this proceeding. However, it is also important to evaluate the impacts on total revenue and average customer bills, since base rates is only a portion of total gas costs. In the following sections of my Direct Testimony, I provide these rate design and total bill impact analyses, which I present in the following sections of my Direct Testimony.

IV. PRINCIPLES OF NATURAL GAS RATE DESIGN

Q. WHAT ARE PUBLIC SERVICE'S FUNDAMENTAL PRINCIPLES WHEN DESIGNING NATURAL GAS RATES?

A. The Company has historically used the following six principles to guide its design of rates:

1) send accurate price signals that encourage efficient use of energy;
2) recover costs equitably from customer classes based on the costs they impose;
3) afford the Company a reasonable opportunity to recover the Commission-approved revenue requirement;
4) offer services and rates that are easy for customers to understand;
5) prevent large rate impacts; and

Q. PLEASE ELABORATE ON THESE FIVE PRICING PRINCIPLES.

A. These principles are typical of most utilities. Because no single rate design is perfect for every situation, the principles balance concepts of equity, accuracy, and applicability. Striking the appropriate balance of pricing objectives requires an exercise of informed judgment. I believe that the Company's proposed rates in this proceeding are just and reasonable and in the best interests of our customers, the Company, and the State of Colorado.

The first principle, "send accurate price signals that encourage efficient use of energy," refers to the concept that the prices that customers pay should be reflective of the costs the Company incurs to provide service. Basic economic theory suggests that if a product is priced at the marginal cost of production, then consumer demand for the product will result in the economically efficient level of natural gas usage. However, pricing at the marginal cost of energy ignores the large amount of fixed costs that all utilities have, so this principle must be balanced with others to account for the difference between the marginal and average costs of providing natural gas service.

The second principle, “recover costs equitably from customer classes based on the costs they impose,” relates to class cost allocation. In general, this principle suggests that costs should be assigned to broad classes of customers based on their relative usage of the natural gas system and subsequently recovered from those same customers through proper rate design.

The third principle, “afford the Company a reasonable opportunity to recover the Commission-approved revenue requirement,” means that rate design should result in a reasonably stable revenue stream. This is one reason that charges for natural gas are spread evenly throughout the year. If a majority of charges were assessed in one season, one month, or even one day, the revenue stream that the Company relies upon to build and maintain a safe and reliable natural gas system may become unstable. This principle also suggests that rates should be set such that they would recover the Commission-approved revenue requirement using the Test Year billing determinants. Later in my Direct Testimony I provide a revenue proof that demonstrates how the proposed rates would result in total base rate revenue equal to the revenue requirement target.

The Company’s fourth principle of pricing is “offer services and rates that are easy for customers to understand.” The Company offers straightforward natural gas rates for residential and small commercial customers. Rate structures are slightly more complicated for large commercial customers and customers choosing to transport natural gas through the Public Service system.

The fifth pricing principle, "prevent disproportionate impacts," is tied to making large changes to existing rate structures. When designing rates, I typically begin with rates that are based on the results of the CCOSS model, but then I evaluate how those new rates may impact various customers. I may modify the rates as necessary to avoid any large bill impacts associated solely with rate design.

Q. WHAT ARE PUBLIC SERVICE'S CURRENT NATURAL GAS RATE SCHEDULES?

A. Table SWW-D-10 below summarizes the existing natural gas rate schedules and basic base rate structures.

Table SWW-D-10
Current Public Service Natural Gas Rate Schedules

Rate Schedule	Fixed Charge	Volumetric Charge	Demand Charge
Residential (RG)	Monthly S&F[10]	Usage Charge	
Small Commercial (CSG)	Monthly S&F	Usage Charge	
Large Commercial (CLG)	Monthly S&F	Usage Charge	Capacity Charge
Interruptible Sales (IG)	Monthly S&F	Usage Charge	
Transport Small (TFS)	Monthly S&F	Usage Charge	
Transport Large (TFL)	Monthly S&F	Usage Charge	Capacity Reservation Charge
Interruptible Transport (TI)	Monthly S&F	Usage Charge	
Gas Lighting (RGL & CGL)	Fixed Monthly Charge Per Mantle		

Q. GIVEN THE COMPANY'S FIVE PRICING PRINCIPLES, CURRENT RATE STRUCTURES, AND THE RESULTS OF THE CCOSS, WHAT RATE CHANGES ARE YOU RECOMMENDING?

A. I am recommending updates to all of Public Service's natural gas rates. While I recommend keeping the basic rate structure for all schedules, the base rate charges must be updated to recover the proposed revenue distribution by class that results from the CCOSS. The existing basic rate structure by rate schedule supports the pricing principles that I described above. They balance accuracy, equity, and simplicity, and, once the base rates are approved and implemented,

[10] "S&F" refers to the Service and Facilities charge.

they will provide a fair opportunity for the Company to recover its Commission-approved revenue requirement.

V. RECOMMENDED CHANGES TO NATURAL GAS RATES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I address each of the Company's natural gas rate schedules. I provide a brief description of each and make recommendations for modifying the base rate charges to collect the Company's proposed revenue distribution based on the results of the CCOSS. The class allocated revenues, billing quantities, and calculations used to derive the recommended rate modifications are provided in Confidential Attachment SWW-2. Unless otherwise noted, references to the "Settled Rates" in this Section of my Direct Testimony are intended to refer to the base rate charges settled and recommended for approval in the 2019 Gas Phase II.[11] Attachment SWW-3 to my Direct Testimony contains the currently effective rates, the 2019 Gas Phase II "Settled Rates," and the Company's base rates proposed in this Proceeding.

A. Residential Service

Q. PLEASE PROVIDE AN OVERVIEW OF THE RESIDENTIAL CUSTOMER CLASS AND THE STRUCTURE OF SCHEDULE RG.

A. The Residential class is the largest rate class in Public Service's natural gas business. Sales under Schedule RG accounted for 39 percent of total volumes in the Test Year. The rate consists of a fixed monthly S&F charge per service meter and a volumetric usage charge.

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[11] As mentioned earlier in my Direct Testimony, unless additional action is taken by the Commission, the Phase II Decision will become a decision of the Commission on February 12, 2020, and new rates will be implemented effective March 1, 2020.

Q. WHAT MODIFICATIONS ARE YOU RECOMMENDING FOR SCHEDULE RG?

A. I recommend that the monthly S&F charge[12] be increased from $12.00 per month to $15.00 per month, and that the remaining revenue requirement allocated to the Residential class through the CCOSS be collected through the volumetric usage charge.

Q. WHY ARE YOU RECOMMENDING THAT THE RESIDENTIAL S&F CHARGE BE SET AT $15.00 PER MONTH?

A. I am recommending an increase in the residential S&F charge relative to the Settled Rates level of $12.00, because this pricing level represents a reasonable balance among the pricing principles I discussed earlier in my Direct Testimony. Specifically, an S&F charge of $15.00 per month is a reasonable reflection of customers' costs provided by Public Service. It will offer the Company a reasonable opportunity to recover its fixed costs and will result in minimal bill impacts. I also recommend that the remaining revenue requirement allocated to the Residential class be recovered through a flat usage charge of $0.17625 per therm.

Based on the results of the CCOSS, the proposed $15.00 S&F Charge will cover the average costs of customer services such as billing and meter reading, as well as customer specific equipment such as meters and service laterals that run to customer premises. The proposed S&F Charge will also cover a portion of O&M expenses needed to maintain the natural gas delivery system.

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[12] The stated S&F charges in this section do not include the 15-cent adder for the GAP. The Company is not proposing to change any of the GAP adder amounts in this proceeding.

The proposed S&F Charge will allow Public Service a reasonable opportunity to recover the cost of providing safe and reliable service to customers. However, revenues from the proposed $15.00 S&F Charge will be much lower than the fixed costs identified in the CCOSS. The cost classification in the CCOSS shows that only two percent of costs allocated to the residential customers are variable in nature, and the remaining 98 percent are fixed and do not change as a result of customer usage. Under the proposed rate design, 43 percent of revenue from the Residential class will be based on usage charges, leaving Public Service at risk for under recovery of fixed costs.

Q. HOW DOES THE PROPOSED RESIDENTIAL RATE DESIGN COMPARE TO THE SETTLED RESIDENTIAL RATES?

A. This rate design is almost identical to the design underlying the settled residential S&F charge of $12 per month. While the Company recognizes that the rate design underlying the Settled Rates was not agreed to as part of the Phase II Settlement, the settled residential S&F charge was higher than the CCOSS-based rate because it included 23.1 percent of the demand-related costs that were identified in the CCOSS.[13] The proposed $15.00 residential S&F charge in this case follows the same methodology by including 25.8 percent of the demand-related costs identified in the CCOSS model. Figure SWW-D-3 demonstrates how demand-related costs were split between the monthly S&F charge and the usage charge in

[13] The Phase II Settlement, at paragraph 7 on page 10, states " . . . the settlement rates and rate design have been agreed to by the Settling Parties solely for the purposes of settlement and do not constitute a settled practice or otherwise have precedent-setting value in any future proceedings."

the 2019 Gas Phase II's Settled Rates, and in my proposed rate design in this Proceeding.

Figure SWW-D-3:
Residential Rate Design for 2019 Gas Phase II Settled Rates vs 2020 Combined Case

2019 Phase II

	Customer Related Costs		Demand Related Costs		Commodity Related Costs	
	$144,205,069		$161,156,369		$4,273,808	
	$37,183,751	23.1%		76.9%	$123,972,618	
Total Costs	$181,388,820				$128,246,426	
Quantity	÷ 15,115,735	customer months			÷ 966,597,900	Therms
Rate	$12.00	per month			$0.13268	per Therm

Proposed Residential Rate Design

	Customer Related Costs		Demand Related Costs		Commodity Related Costs	
	$177,386,408		$236,495,619		$4,832,564	
	$61,019,389	25.8%		74.2%	$175,476,230	
Total Costs	$238,405,797				$180,308,794	
Quantity	÷ 15,893,720	customer months			÷ 1,023,001,068	Therms
Rate	$15.00	per month			$0.17625	per Therm

Q. WHY IS IT APPROPRIATE TO SPLIT THE RECOVERY OF DEMAND-RELATED COSTS BETWEEN THE S&F CHARGE AND THE USAGE CHARGE?

A. The Company does not believe that basing the residential S&F charge on customer-related costs only is appropriate, as such a methodology would result in large changes to established rates and would have adverse bill impacts for a large percentage of residential customers. Absent a separate demand charge for demand-related costs, the next best approach is to split the recovery of demand-related costs between the S&F charge and the usage charge. Including demand-related costs in the S&F charge is representative of the fact there is a minimum fixed amount of demand-related costs that do not vary by customer, and therefore it is appropriate to recover this amount through a fixed charge.

Q. WHAT WOULD THE S&F CHARGE BE IF ALL FIXED COSTS WERE INCLUDED?

A. Under a straight fixed/variable rate design, where all fixed costs are included in the fixed service and facility charge, the residential monthly S&F charge would be $26.04 instead of the $15.00 monthly charge that I am proposing.

Q. DOES AN S&F CHARGE THAT IS NOT INCLUSIVE OF ALL FIXED COSTS LEAVE THE COMPANY AT RISK FOR FULL FIXED COST RECOVERY?

A. Yes. Including only a portion of the total fixed costs in the S&F Charge means that that the remainder of the fixed costs are to be recovered through the residential volumetric charge. This creates the potential for significant under-recovery of costs if residential sales are lower than Test Year billing determinants.

Q. WHY AREN'T YOU PROPOSING THE USE OF STRAIGHT FIXED/VARIABLE PRICING WITH A MONTHLY SERVICE AND FACILITY CHARGE OF $26.03?

A. My primary reason for not proposing the use of straight fixed/variable pricing is to provide stability in residential bills by using a rate design that is similar to the rate design used by the Company in the 2019 Gas Phase II. Although a straight fixed/variable rate design has an intuitive economic appeal, some low usage customers would experience relatively larger bill increases. Therefore, moving to a full straight fixed/variable rate design in this proceeding would challenge the fifth rate design principle I described earlier.

Q. WILL THE COMPANY'S PROPOSED RATE DESIGN RESULT IN DISPROPORTIONATE BILL INCREASES FOR LOW INCOME CUSTOMERS?

A. No. The Company's proposed residential rate design balances fixed cost recovery through the S&F Charge with a reasonable increase to the volumetric charge. If the residential S&F charge remained at $12.00, the volumetric charge would have increased even more than proposed to collect the total costs that have been allocated to the residential class. If the residential S&F charge was held at $12.00 per month, the resulting volumetric charge would be $0.22286 per therm, which 26 percent higher than the $0.17625 per therm volumetric charge that the Company is proposing. That higher volumetric rate would result in increased volumetric rate pressure for all residential customers but particularly for low income customers with relatively high usage.

Q. ARE THERE ASSISTANCE PROGRAMS AVAILABLE FOR LOW INCOME CUSTOMERS?

A. Yes. Public Service administers the Gas Affordability Program (previously defined as "GAP") for low-income natural gas customers. This program has provided direct bill assistance to low income customers since 2009. Its current enrollment by gas customers is approximately 18,000, and in 2019, the program provided over $4.3 million in bill payment assistance. On average, GAP participants received approximately $20.00 per month, which more than offsets the proposed monthly S&F charge increase of $3.00.

B. Small Commercial Gas Service – Schedule CSG

Q. PLEASE PROVIDE AN OVERVIEW OF THE SMALL COMMERCIAL RATE SCHEDULE CSG.

A. Schedule CSG is similar to the residential rate in that it has only two components, a monthly S&F charge per service meter and a usage charge. In the Test Year, there are about 100,000 Small Commercial gas customers that account for approximately 13 percent of the Test Year sales volumes.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING FOR SCHEDULE CSG RATES?

A. I recommend that the S&F charge be set to $55.00 per month, which is an increase of $12.00 from the Settled S&F charge of $43.00.[14] I also recommend that the remaining revenue requirement be collected through a flat usage charge of $0.15798 per therm.

Q. HOW DID YOU DERIVE THE RECOMMENDED BASE RATE CHARGES FOR SCHEDULE CSG?

A. The CCOSS combines the sales volumes and revenue requirements for Schedule CSG and Schedule TFS customers into a Small General class, so that a single rate can be derived for both. While the Company recognizes that the rate design underlying the Settled Rates was not agreed to as part of the Phase II Settlement, I first used the approximate split of demand-related costs collected through the Settled S&F charge to establish the $55.00 S&F charge being proposed in this

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[14] The referenced S&F charges in this section do not include the GAP adder. For CSG, the additional charge is $0.58 per month and is included in the S&F charge on customer bills.

case. I then calculated what the usage charge would have to be in order to collect the remaining allocated revenue requirements.

Q. HOW DO THE PROPOSED RATES FOR SCHEDULE CSG COMPARE TO SETTLED RATES?

A. The proposed S&F charge of $55.00 per month is 28 percent higher than the Settled S&F charge of $43.00. The customer-related costs allocated to the Small General rate class increased by 29 percent. This increase is driven primarily by the capital investments in the service lines that run from the nearby main pipe to the customers meter., resulting in a commensurate increase in the S&F charge. The proposed volumetric charge of $0.15798 per therm is 36 percent higher than that the Settled volumetric rate of $0.11585 per therm.

With the proposed rates, the Small Commercial sales rates will collect about $67 million through the fixed S&F charge and about $56 million through the volumetric charge. So, although 98 percent of Public Service's natural gas costs are fixed, the Company is recommending that large portion of the cost recovery be embedded in the volumetric charge for CSG customers. By assigning revenue requirements to the volumetric charge, CSG customers will have enhanced incentive to engage in conservation measures.

C. Large Commercial Gas Service – Schedule CLG

Q. PLEASE PROVIDE AN OVERVIEW OF THE LARGE COMMERCIAL SALES CLASS, RATE SCHEDULE CLG.

A. The rate schedule CLG is for sales customers with total annual usage of 5,000 Dth or more. In the proposed Test Year there are approximately 760 CLG customers with an average usage of about 8,500 Dth. Schedule CLG is a relatively small group of customers and accounts for only two percent of Test Year sales volume.

Schedule CLG has a three-part rate design with a fixed monthly S&F charge per service meter, a demand charge based on the customer Maximum Daily Quantity ("MDQ"), and a usage charge that is applied to total monthly volumes.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING FOR SCHEDULE CLG RATES?

A. I recommend that the S&F charge increase to $120.00 per month,[15] the demand charge increase to $12.00 per Dth, and that the usage charge be set to $0.3419 per Dth.

Q. HOW DID YOU DERIVE THE RECOMMENDED BASE RATE CHARGES FOR SCHEDULE CLG?

A. Similar to the Small General class, Schedule CLG and Schedule TFL are combined into a single Large General customer class within the CCOSS model so that the same base rate levels can be derived for both rate schedules. Beginning with the combined revenue requirements, I calculated the S&F charge based on the revenue requirement classified as customer-related. The resulting value was $116.59, which I rounded to $120 per month. In the case of Schedule CLG, there is no need to include demand-related costs in the S&F charge because the rate structure includes a separate demand charge. Next, I calculated what the demand charge would be based strictly on the demand-related costs allocated to the Large General class. This value was $13.86 per Dth. I am recommending that the

[15] The referenced S&F charges in this section do not include the $5.12 adder for GAP.

capacity charge be set to only $12.00 per Dth to ameliorate the impact on customers with high demand volumes. I concluded by calculating the volumetric charge necessary to recover the remaining costs that were allocated to the Large General class. By moderating the capacity demand charge and moving some of the demand-related costs to the volumetric charge, there will be greater incentive with this rate design for customers to conserve natural gas.

Q. HOW DO THE PROPOSED RATES COMPARE TO THE SETTLED RATES FOR SCHEDULE CLG?

A. The monthly S&F charge increased significantly from the Settled Rate. I based the proposed S&F charge on the customer-related costs that were allocated to the Large General class. While the proposed S&F charge of $120.00 is a 24 percent increase over the Settled Rate of $96.00 per month (not including the $5.12 adder for GAP) the impact on CLG customer bills will be minimal. This is because the S&F charge represents a very small portion of CLG customers' bills. Due to their large consumption of natural gas, the average monthly bill for CLG customers is approximately $3,000, so the impact of increasing the S&F charge by $24.00 is minimal.

The recommended capacity demand charge of $12.00 per Dth is 37 percent higher than the Settled Rate of $8.73 per Dth. As previously discussed, most of the revenue requirement increase in this case is associated with an increased allocation of demand-related costs, driven by investments in our pipeline infrastructure. As such, the capacity demand charges need to be increased commensurately.

The proposed usage charge of $0.3419 per Dth for Schedule CLG is 50 percent higher than the Settled Rate of $0.2302 per Dth. Part of this increase is associated with a slight discrepancy in commodity volumes in the 2019 Gas Phase II CCOSS analysis. In that prior study, a portion of sales volumes attributable to the large commercial class were inadvertently omitted in the cost allocation calculations. The result was that fewer commodity-related costs were allocated to the Large General class. The analysis in this proceeding corrects the allocation, which results in a slightly higher allocation in costs to the Large General class

D. Interruptible Industrial Gas Service – Schedule IG

Q. PLEASE PROVIDE AN OVERVIEW OF THE INTERRUPTIBLE INDUSTRIAL GAS SERVICE, SCHEDULE IG.

A. Schedule IG provides natural gas service on an interruptible basis to commercial and industrial customers. Customers on Schedule IG can be asked to curtail their use of natural gas until system conditions return to normal.

The basic rate structure is a monthly S&F charge per service meter plus a usage charge that is substantially lower than usage charges for Schedules TFS and RG. The usage charge is lower because service under IG can be interrupted if necessary. Customers may contract for a portion of their load to be uninterruptible by specifying a level of on-peak demand in their service agreements. This is an important option because customers may have a portion of their load that cannot be interrupted. IG customers pay the same demand charge included in Schedule CLG for contracted on-peak demand.

Q. WHAT MODIFICATIONS ARE YOU RECOMMENDING FOR SCHEDULE IG?

A. I recommend maintaining the basic structure of Schedule IG rates with an S&F charge, a usage charge, and a demand charge for reserved on-peak gas. Based on the results of the CCOSS, I recommend setting the S&F Charge to $43.00 per month[16] and the usage charge at $0.4968 per Dth. I also recommend that the on-peak demand charge be set equal to the demand charge for CLG, which is $12.00 per Dth.

Q. HOW DO THE PROPOSED RATES COMPARE TO THE SETTLED RATES FOR SCHEDULE IG?

A. Both the S&F charge and the usage charge are increases as compared to Settled Rates. The Settled S&F charge is $34.00 per month and the recommended rate is $43.00 per month, which is a 26 percent increase. The Settled usage charge is $0.3476 per Dth and the proposed rate is $0.4968 per Dth, which is a 43 percent increase.

Q. BASED ON YOUR RECOMMENDED RATES WHAT WILL BE THE IMPACT ON TOTAL REVENUES COLLECTED FROM THE IG CLASS?

A. I calculated that the base rate revenues collected from IG customers will increase by $84,000. In comparison to the total base rate revenue requirement, this increase is insignificant.

[16] This S&F charge does not include the GAP adder of $7.00.

E. Small Firm Transportation Service – Schedule TFS

Q. PLEASE PROVIDE AN OVERVIEW OF THE SMALL FIRM TRANSPORTATION RATE SCHEDULE TFS.

A. Schedule TFS is for small commercial and industrial customers who transport less than 5,000 Dth across the Company's natural gas system on a firm basis. These transportation customers secure their own natural gas supply and use Public Service's pipeline to move the commodity from the point of receipt to the point of delivery. In the Test Year, Schedule TFS has about 6,400 customers which accounts for about four percent of the total volume of gas supplied to customers.

The base rate structure for Schedule TFS is a two-part rate design with a monthly S&F charge per service meter, and a usage charge for the total volume of natural gas transported in a month. In the 2011 Gas Phase II case, symmetry between natural gas sales rates and transport-only rates was established, such that the cost of natural gas delivery would be the same between the two options. The only difference between the base rates for natural gas sales and the base rates for transportation service is an additional cost that is added to the S&F charge that accounts for the administrative costs associated with transportation contracts, referred to as the transportation adder.

Q. WHAT CHANGES TO SCHEDULE TFS ARE YOU RECOMMENDING?

A. I recommend that the basic base rate structure of Schedule TFS stay the same and that the rate symmetry established between Schedules TFS and CSG be maintained. I support the symmetry of base rates because it makes Public Service financially indifferent between supplying natural gas sales or transportation-only services. This economic indifference avoids the possibility that the Company would favor one type of service over the other.

I recommend that the base S&F charge and the usage charge be set equal to the rates I proposed for Schedule CSG. Specifically, I recommend that the base S&F charge be set to $78.00 per month, and the usage charge be set to $1.5798 per Dth. The S&F charge of $78.00 includes a recommended transportation adder of $23.00 per month (not including the GAP charge), which is an increase from the settled $15.00 transportation adder charge from the 2019 Gas Phase II. The increase in the transportation adder is associated with the new gas transportation system software that is used to schedule the receipt and delivery of transportation customers' gas[17]. Specifically, in the 2019 Gas Phase II, the Company recommended several modifications to the terms and conditions associated with gas transport that were facilitated by the new software system and necessary under industry standards. However, the revenue requirement in the 2019 Gas Phase II was based on a 2016 HTY that did not include the cost of the new software system. The proposed Test Year in this case does include those software system costs, and therefore the transportation adder necessarily will be increased. With the transportation adder, the total Schedule TFS S&F charge as reflected on Rate Schedule TFS would be $80.00 per month.[18]

[17] The referenced software is the Quorum Pipeline Transaction Management System, which is discussed by both Mr. Litteken and Company witness Mr. Sridhar Koneru in their Direct Testimonies.
[18] The S&F charges in this section do not include the $0.58 GAP charge approved to be included as part of the TFS S&F charge in the Phase II Settlement.

I also note that certain other rates within the TFS Rate Schedule are tied to the amount of base rates. As a result, the Unauthorized Overrun Penalty minimum rate and the Backup Sales Supply rates will be adjusted to match the standard usage charge.

F. Large Firm Transportation Service – Schedule TFL

Q. PLEASE PROVIDE AN OVERVIEW OF THE LARGE FIRM TRANSPORTATION RATE SCHEDULE TFL.

A. Schedule TFL consists of a three-part rate design for base rates (S&F charge per service meter, demand charge ("Firm Capacity Reservation Charge" for Settled Rates, and usage charge). Schedule TFL also includes a customer option for Backup Sales service. As was the case for the Small General class, the 2011 Gas Phase II established symmetry between the rates charged to large natural gas sales customers and large transport-only customers.

The Large Transport class is Public Service's second largest class. In the proposed Test Year, there are about 1,800 large transport customers, who account for 35 percent of the natural gas moving through the Public Service system.

Q. WHAT CHANGES ARE YOU PROPOSING FOR SCHEDULE TFL?

A. I recommend maintaining symmetry with Schedule CLG such that the base S&F charge is $120.00 per month, the standard Firm Capacity Reservation charge is $12.00 per Dth, and the standard usage charge is $0.3419 per Dth. I also recommend that the same $25.00 per month transportation adder be included in the monthly S&F rate, bringing the total charge to $143.00 per month.[19]

I also note that certain other rates within the TFL Rate Schedule are tied to the amount of base rates. As a result, the Authorized Overrun Charge and Unauthorized Overrun Penalty minimum rate will be adjusted to match the standard usage charge. The Authorized Overrun Charge is adjusted to match the Schedule TI standard usage charge, consistent with the 2019 Gas Phase II.

Q. HOW DO THE PROPOSED SCHEDULE TFL RATES COMPARE TO SETTLED RATES?

A. The total S&F charge of $143.00 (not including the GAP charge) is an increase from the Settled Rate of $111.00. The changes in Firm Capacity Reservation and Usage Charges for Schedule TFL are the same as the changes I described for Schedule CLG. In particular, the standard Firm Capacity Reservation Charge is an increase from the Settled Rate of $8.73 per Dth to $12.00 per Dth, an increase of 37 percent.

G. Interruptible Transportation Service – Schedule TI

Q. PLEASE PROVIDE AN OVERVIEW OF INTERRUPTIBLE TRANSPORTATION SERVICE, SCHEDULE TI.

A. Interruptible transportation service is a rate option for transportation customers who are willing to curtail their shipments of natural gas during peak demand periods, in exchange for a lower overall cost of transportation services. Schedule

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[19] The S&F charges in this section do not include the $5.12 GAP charge approved to be included as part of the TFL S&F charge in the Phase II Settlement.

TI is a two-part rate design with a monthly S&F charge per service meter, and a usage charge applied to the total monthly volume of gas shipped through the Public Service system. Schedule TI customers may elect to designate a portion of their load as uninterruptible and pay an On-Peak Demand Quantity Charge that is equivalent to the standard Firm Capacity Reservation Charge (demand charge) used in Schedules CLG and TFL.

In the proposed Test Year, there are approximately 170 customers utilizing Schedule TI. These customers account for seven percent of the natural gas throughput on the Public Service system.

Q. WHAT MODIFICATIONS ARE YOU RECOMMENDING FOR SCHEDULE TI?

A. Based on the results of the CCOSS, I recommend that the S&F charge be set to $163.00 per month (not including the GAP charge).[20] The proposed S&F charge includes a base charge of $140.00 plus a transportation adder of $23.00. In addition, based on the results of the CCOSS model, I recommend increasing the standard usage charge for Schedule TI to $0.5058 per Dth from the Settled Rate of $0.3539. Finally, I recommend that the charge to reserve on-peak gas is set equal to the Firm Capacity Reservation charge for Schedules TFL and CLG.

[20] The S&F charges in this section do not include the $7.00 GAP charge approved to be included as part of the TI S&F charge as part of the Phase II Settlement.

H. Gas Lighting Service

Q. PLEASE PROVIDE AN OVERVIEW OF THE GAS LIGHTING SERVICES THAT THE COMPANY OFFERS.

A. Public Service has two legacy tariffs for natural gas lighting: residential gas lighting, Schedule RGL; and Commercial gas lighting, Schedule CGL. The tariff specifies that these services are only available to natural gas lights installed prior 1976, which effectively closes the rate to new participation. The rates are based on fixed monthly charges. The first charge covers two mantles, and the second charge is for each additional mantle. In the Test Year, there are approximately 26 gas lighting customers with total base rate revenue of about $4,600.

Q. WHAT CHANGES DO YOU RECOMMEND FOR SCHEDULES RGL AND CGL?

A. I propose to increase the base rates for lighting by an amount approximately proportional to the general increase in base rate revenue requirement. The result is an increase of 30 percent for all gas lighting charges.

VI. CUSTOMER BILL IMPACTS AND REVENUE PROOF

Q. HAVE YOU CONDUCTED AN ANALYSIS OF THE EXPECTED IMPACTS ON CUSTOMERS' BILLS ASSOCIATED WITH THE COMPANY'S RECOMMENDED CHANGES TO NATURAL GAS BASE RATES?

A. Yes. I prepared an analysis that compares estimated bills under the currently effective, Settled, and proposed rates. To conduct this analysis, I applied the current base rates (inclusive of GAP charges and GRSA) and current rate riders to the average sales volumes for each rate class to derive estimated average monthly bills under current rates. Next, I did the same analysis using the Settled rates from the 2019 Gas Phase II. The third step was to estimate average monthly bills using the proposed rates that I described earlier in my testimony. As part of that analysis, I also updated the PSIA rider, which will be lowered as a result of the Company's proposals in this case.[21] The last step is to compare the three sets of estimated bills. For transportation customers, I included an estimate of the cost of the natural gas commodity that these customers purchase from other suppliers. By doing so, I am able to present the estimated change in their total natural gas service costs. I have included the bill impact analysis as Attachment SWW-4 to my Direct Testimony.

[21] Please see Ms. Trammell's Attachment BAT-1 to her Direct Testimony which provides a summary of the proposed base rate and overall revenue change.

Q. WHAT WERE THE RESULTS OF THE BILL IMPACT ANALYSIS THAT COMPARED THE PROPOSED RATES TO THE 2019 GAS PHASE II SETTLED RATES?

A. Table SWW-D-11 presents the results of the bill impact analysis comparing average monthly bills based on the 2019 Gas Phase II Settled rates to the rates the Company is proposing in this case. I believe that this analysis is most representative of the changes that will result from this proceeding, as it excludes the rate change impacts that are expected to occur on March 1, 2020.

Table SWW-D-11
Estimated Bill Impacts Settled Rates vs Proposed Rates

Rate Schedule	Average Monthly Bills		Change	
	2019 Phase II Settled Rates	Proposed Rates	$	%
Residential (RG)	$40.82	$46.88	$6.05	14.83%
Small Commercial (CSG)	$162.72	$186.78	$24.05	14.78%
Large Commercial (CLG)	$2,931.69	$3,275.06	$343.36	11.71%
Interruptible Sales (IG)	$10,446.80	$10,904.91	$458.11	4.39%
Small Firm Transportation (TFS)	$518.46	$590.98	$72.52	13.99%
Large Firm Transportation (TFL)	$4,420.17	$4,992.58	$572.41	12.95%
Interruptible Transportation (TI)	$25,111.45	$26,343.09	$1,231.64	4.90%

The summary shows that based on the Company's proposed overall base rate revenue requirement increase and resulting class revenue distribution from the CCOSS, the average bills for all rate schedules will increase as compared to the Settled Rates. The large range of bill impacts is partially a result of class cost allocation but is primarily driven by the relative proportion of base rates in each customer's bill. For example, the Residential class has the highest percentage bill impact but also the highest proportion of base rate charges in their monthly bill.

Conversely, Interruptible Sales (IG) customers have the lowest bill impacts and the lowest proportion of base rates in their average monthly bills. The following figure illustrates the relationship between bill impacts and the proportion of base rates in monthly bills. Bill changes are also impacted by other factors such as cost allocation and the increased transportation adder.

Figure SWW-D-4
Relationship Between Bill Impacts and Base Rates in Monthly Bills

Q. WHAT WERE THE RESULTS OF THE BILL IMPACT ANALYSIS THAT COMPARED THE PROPOSED RATES TO THE CURRENT NATURAL GAS RATES INCLUDING THE 24.19 PERCENT GRSA?

A. Table SWW-D-12 provides the results of the bill impact analysis that compared average monthly bills under the Company's rates that were in effect at the time this Direct Testimony was filed, including application of the 24.19 percent GRSA to the proposed rates. This bill change analysis essentially combines the impact of the 2019 Gas Phase II case and this proceeding.

Table SWW-D-12
Estimated Bill Impacts Current Rates vs Proposed Rates

Rate Schedule	Average Monthly Bills		Change	
	Current Rates	Proposed Rates	$	%
Residential (RG)	$40.43	$46.88	$6.44	15.94%
Small Commercial (CSG)	$167.26	$186.78	$19.51	11.67%
Large Commercial (CLG)	$2,879.78	$3,282.05	$402.27	13.97%
Interruptible Sales (IG)	$10,517.81	$10,870.23	$352.42	3.35%
Small Firm Transportation (TFS)	$552.44	$590.98	$38.54	6.98%
Large Firm Transportation (TFL)	$4,347.59	$4,992.58	$644.99	14.84%
Interruptible Transportation (TI)	$25,324.74	$26,343.09	$1,018.35	4.02%

Q. CAN YOU DEMONSTRATE THAT THE PROPOSED NATURAL GAS RATES WILL RECOVER THE APPROVED REVENUE REQUIREMENT?

A. Yes. The rates that I have recommended are designed to recover the target revenue requirement of $644,483,385. This target is based on the total revenue requirement sponsored by Ms. Blair in her Direct Testimony, less other revenue associated with non-gratuitous services.

The revenue proof analysis begins with the Test Year weather normalized sales volumes that were used as the basis of the Company's revenue deficiency calculations. Next, the proposed rates are applied to the Test Year billing quantities to derive an estimate of total revenue under the proposed rates. Confidential Attachment SWW-5 provides these revenue proof calculations. The revenue proof analysis shows that the proposed rates come within $1,295 of the target $644,483,385. It is not possible to close to the exact revenue requirement target due to rounding of rates.

VII. RATE SCHEDULE AND OTHER TARIFF CHANGES

Q. IS THE COMPANY PROPOSING CHANGES TO THE COMPANY'S RATE SCHEDULES OR OTHER PORTIONS OF ITS GAS TARIFF?

A. Yes. Mr. Berman sponsors changes to the Company's PSIA tariff, other than the changes to the PSIA rate that I discuss earlier in my Direct Testimony. In addition to the PSIA rate changes, I sponsor the remainder of the Company's proposed tariff changes. Specifically, I am sponsoring the changes to the Company's base rates, as discussed herein and as reflected in the tariff sheets attached to Advice No. 961 filed contemporaneously herewith. I also sponsor the changes to certain transportation rate schedule charges, such as those for backup sales and authorized overrun charges, to align with those base rates changes. There are also a few administrative changes, including changing the word "customer" to "service meter" in the sales rate schedules, so that the same terminology is used in both the sales and transport rate schedules, and making a minor housekeeping correction to the Rules and Regulations - Distribution Extension Policy Tariff Sheet No. R72. All tariff changes I am sponsoring are reflected in Attachment SWW-6 to my Direct Testimony, in redline as compared to the currently effective tariff sheets. A clean version of those same tariff sheets is found in Attachment SWW-7 to my Direct Testimony.

Q. WILL THERE BE INTERVENING TARIFF CHANGES FROM THE DATE OF FILING THIS CASE TO THE PROPOSED EFFECTIVE DATE OF NOVEMBER 1, 2020, AFTER SUSPENSION?

A. Yes. As mentioned earlier in my Direct Testimony, the Settled Rates and tariff changes resulting from the 2019 Gas Phase II are recommended for approval by the Phase II Decision, and will go into effect on March 1, 2020, unless further action is taken by the Commission. Because that is after the date of filing this rate case, the tariff sheets attached to Advice No. 961 provide rate and tariff changes as compared to the Company's *currently-effective* tariff sheets, as required. At the time new rates go into effect as a result of this Proceeding, the Settled Rates, along with all other terms and conditions approved to change as a result of the 2019 Phase II Settlement will be included within the then-current tariff sheets, which will be different in substance from those in effect today.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Steven W. Wishart

I began my employment with Xcel Energy Services, Inc. in 2005, in the Company's Demand-Side Management department. I am currently a Manager in the Pricing and Planning Group. My responsibilities include quantitative analyses, cost allocation, and rate design, and policy support on a number of Colorado regulatory issues.

Prior to taking my current position, I worked for Xcel Energy Services Inc. in Minneapolis, Minnesota, as Director of Resource Planning and Bidding for the Northern States Power region. In that role, I oversaw resource planning and resource acquisition processes for that company.

From 2009 through 2012, I worked for the Company as the Manager of Quantitative Analytics. In that role, I managed a group responsible for conducting long-term analyses of the costs and performance of Xcel's electric generating systems.

Prior to joining Xcel Energy in 2005, I was a PhD candidate in the Department of Applied Economics at the University of Minnesota where I studied energy-related topics.