BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend its Filed Tariffs to Increase the Rates and Charges for Gas Services and Related Matters.	)))))	Case No. 21-637-GA-AIR
In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation.	)))	Case No. 21-638-GA-ALT
In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of a Demand Side Management Program for its Residential and Commercial Customers.	)))))	Case No. 21-639-GA-UNC
In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval to Change Accounting Methods.	)))	Case No. 21-640-GA-AAM

PREPARED DIRECT TESTIMONY OF
RUSSELL A. FEINGOLD
ON BEHALF OF COLUMBIA GAS OF OHIO, INC.

☐ Management policies, practices, and organization
☐ Operating income
☐ Rate base
☒ Allocations
☐ Rate of return
☒ Rates and tariffs
☐ Other

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Russell A. Feingold. My business address is 2525 Lindenwood Drive, Wexford, Pennsylvania 15090.

Q. By whom are you employed?

A. I am employed by Black & Veatch Management Consulting, LLC ("Black & Veatch") as a Vice President and a senior member of its Rates & Regulatory Practice.

Q. Please describe the firm of Black & Veatch.

A. Black & Veatch Corporation (the parent company of Black & Veatch) has provided comprehensive engineering and management services to utility, industrial, and government entities since 1915. Black & Veatch delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas. From an industry-wide perspective, Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis, and regulatory practices and policies, gained through management and operating responsibilities at gas distribution, pipeline, and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas and electric distribution companies located in the U.S. and Canada.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Electrical Engineering from Washington University in St. Louis and a Master of Science Degree in Financial Management from Polytechnic Institute of New York University.

Q. Have you previously testified before the Public Utilities Commission of Ohio ("Commission") or any other regulatory authority?

A. Yes. I have testified before this Commission on behalf of Columbia Gas of Ohio, Inc. ("Columbia") in Case Nos. 91-195-GA-AIR and 08-0072-GA-AIR and Vectren Energy Delivery of Ohio in Case No. 18-0298-GA-AIR on the subjects of cost of service studies, class revenue apportionment, and rate design, including Straight Fixed-Variable ("SFV") rate design. I have also presented expert testimony before the Federal Energy Regulatory Commission ("FERC"), the National Energy Board of Canada, and numerous other state and provincial regulatory commissions. My expert testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution and gas pipeline companies.

In addition to traditional utility costing and rate design concepts and issues, my testimony addressed revenue decoupling concepts and other innovative ratemaking approaches, gas transportation rates, gas supply planning issues and activities, market-based rates, Performance-Based Regulation ("PBR") concepts and plans, competitive market analysis, gas merchant service issues, strategic business alliances, market power assessment, merger and acquisition analyses, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, cogeneration rates, and pipeline ratemaking issues related to the importation of gas into the United States.

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

A. I have over forty-six years of experience in the utility industry, the last forty-three years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade and research organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies, and market planning. In addition to expert testimony in utility regulatory proceedings, I have spoken widely on issues and activities dealing with the pricing and marketing of gas utility services. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as Attachment RAF-1.

Q. Please summarize your specific experience in conducting class cost of service studies and designing rates for gas and electric utilities.

A. Over my utility consulting career, I have conducted numerous class cost of service studies for gas and electric utilities to provide guidelines for use in evaluating the utilities' class revenue levels and rate structures. In addition to these cost studies, which are based on a utility's embedded or historical costs, I have conducted long-run and short-run marginal cost, avoided cost, and unbundled service and cost studies. Finally, I have reviewed, evaluated, designed, and implemented rate structures and other innovative pricing approaches for numerous gas and electric utilities operating in North America and abroad.

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

A. The purpose of my prepared direct testimony is to sponsor, present and explain the Cost of Service Study ("COSS"), class revenue, and rate design proposals submitted by Columbia in this rate proceeding. My testimony specifically addresses: (1) the structure, content, and results of Columbia's COSS, its underlying cost allocation methods, and how its results are used for ratemaking purposes; (2) its proposed class revenue apportionment; and (3) its proposed rate design and the resulting rates by rate class and rate schedule. I am also sponsoring Columbia's revenue schedules and monthly bill comparisons by rate class.

Q. Would you please identify the attachments and schedules you are sponsoring in this proceeding?

A. I am sponsoring the following attachments and schedules:

- Attachment RAF-1 – Educational Background, Work Experience and Regulatory Experience
- Attachment RAF-2 – Proposed Class Revenue Apportionment and Rate Design Development
- Attachment RAF-3 – Monthly Fixed Charge Comparison and Derivation by Rate Class
- Schedule C-11.1 - Revenue Statistics – Total Company
- Schedule C-11.2 - Revenue Statistics – Jurisdictional
- Schedule C-11.3 - Sales Statistics – Total Company
- Schedule C-11.4 - Sales Statistics – Jurisdictional
- Schedule E-3.1 - Customer Charge/Minimum Bill Rationale
- Schedule E-3.2 - Cost of Service Study
- Schedule E-4 - Class and Revenue Summary
- Schedule E-4.1 - Annualized Test Year Revenue at Proposed and Current Rates
- Schedule E-5 - Typical Bill Comparisons

Q. What is the source of the information contained in the schedules you are sponsoring?

A. The source of the information generally is the books and operating budgets of Columbia. When data comes from another source, I will note that in my testimony if not made clear in the referenced schedules of the Application.

II. COLUMBIA'S REVENUE AND SALES STATISTICS

Q. Please describe Schedule C-11.1.

A. Schedule C-11.1, Pages 1 of 4 and 2 of 4, show by revenue class for the most recent five calendar years and test year, sales revenue, transportation revenue, average number of customers, customers served at end of year, average revenue per customer sales, and average revenue per customer transportation. Schedule C-11.1, Pages 3 of 4 and 4 of 4, show by revenue class for the next five calendar years, projected sales revenue, projected transportation revenue, projected average number of customers, projected number of customers served at end of year, projected average revenue per customer sales, and projected average revenue per transportation customer. The source of this data was Columbia's records and approved budget.

Q. Please describe Schedule C-11.2.

A. Schedule C-11.2 would normally show the information shown on Schedule C-11.1 for the jurisdiction. This schedule was not completed by Columbia since all of its sales and transportation revenue are jurisdictional.

Q. Please describe Schedule C-11.3.

A. Schedule C-11.3, Pages 1 of 4 and 2 of 4, show by revenue class for the most recent five calendar years and test year, sales volumes, transportation volumes, average number of customers, customers served at end of year, average volumes delivered to a sales customer and average volumes delivered to a transportation customer. Schedule C-11.3, Pages 3 of 4 and 4 of 4 shows by revenue class for the next five calendar years, projected sales volumes, projected transportation volumes, projected average number of customers, projected number of customers served at end of year, projected average volumes delivered per sales customer and projected average volumes delivered per transportation customer. The source of this data was Columbia's records and approved budget.

Q. Please describe Schedule C-11.4.

A. Schedule C-11.4 would normally show the information shown on Schedule C-11.3 for the jurisdiction. This schedule was not completed by Columbia since all of its sales and transportation volumes delivered are jurisdictional.

III. OVERVIEW OF COLUMBIA'S COSS

Q. Has a COSS been submitted in this proceeding?

A. Yes. Schedule E-3.2 of Columbia's filing contains its COSS based upon pro forma revenues and costs for the test year ended December 31, 2021. The study was performed using Black & Veatch's proprietary, computer-based Gas Cost of Service Study Model.

Q. Was this study prepared by you or under your supervision and direction?

A. Yes.

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

A. All cost of service data has been extracted from Columbia's total cost of service (i.e., total revenue requirement) contained in this filing. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from Columbia's historical books and records.

Q. Which rate classes are included in Columbia's COSS?

A. The following rate classes are included in Columbia's COSS: Small General Service ("SGS"), Small General Transportation Service ("SGTS"), and Full Requirements Small General Transportation Service ("FRSGTS"); General Service ("GS"), General Transportation Service ("GTS"), and Full Requirements General Transportation Service ("FRGTS"); Large General Service ("LGS"), Large General Transportation Service ("LGTS"), and Full Requirements Large General Transportation Service; and Full Requirements Cooperative Transportation Service ("FRCTS").

Q. Please describe Schedule E-3.1.

A. Schedule E-3.1 - Customer Charge/Minimum Bill Rationale presents the components of the customer-classified costs for each of Columbia's rate classes. This information is extracted from the COSS which is presented in Schedule E-3.2.

Q. Please describe in more detail Columbia's COSS presented in Schedule E-3.2.

A. Columbia's COSS presented in Schedule E-3.2 is organized as follows:

- Schedule E-3.2-1 presents a tabular summary of results for Columbia's COSS based on its test year at current and proposed rates.
- Schedule E-3.2-2 presents a unit cost analysis based on the functionalized and classified components of Columbia's total revenue requirement.
- Schedule E-3.2-3 presents the complete output detailing the results of Columbia's COSS by FERC account.
- Schedule E-3.2-4 presents the complete output detailing the functionalization and classification phases for the Purchased Gas and Distribution functions.
- Schedules E-3.2-5A through E-3.2-5C present the complete output for allocation to the rate classes of Columbia's functionalized and classified revenue requirement for Purchased Gas Commodity, Distribution Demand and Distribution Customer.
- Schedules E-3.2-6 presents a complete listing of the allocation factors used in the functionalization, classification, and allocation phases of Columbia's COSS.
- Schedule E-3.2-7 lists the functionalization, classification, and class allocation factor(s) used for each FERC account and other cost elements that comprise Columbia's total revenue requirement.

In addition, I am presenting the supporting work papers, designated as WPE-3.2-1 through WPE-3.2-13, which show how the cost allocators external to the COSS were developed. WPE-3.2-1 is the index work paper that lists the information contained in the other work papers.

IV. CONCEPTUAL BASIS FOR CONDUCTING A UTILITY'S COSS

Q. Would you please state the purpose of a COSS?

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

Q. Are there certain guiding principles that should be followed when performing a COSS?

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

The essential element in the selection and development of a reasonable cost allocation methodology for use in conducting a COSS is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand, and the costs incurred by the utility in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

A gas utility's gas distribution system is designed to meet three primary objectives: (1) extend distribution services to all customers entitled to be attached to the system; (2) meet the aggregate, coincident design day capacity requirements of all customers entitled to firm service;[1] and (3) deliver volumes of natural gas to those customers either on a sales or transportation basis. The costs incurred by a utility satisfy one or more of these operational objectives. There is generally a direct link between the way in which costs are defined and their subsequent allocation.

It is a generally accepted concept in the utility industry that customer-related costs are incurred by a gas utility to attach a customer to the distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators, and customer service and accounting expenses.

[1] Columbia's design day capacity requirements are based on the firm customer demands expected to occur on a single day defined by Columbia as having 72 Heating Degree-Days ("HDDs"), or an average daily temperature of -7 degrees Fahrenheit.

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 distribution mains, or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

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 since they vary with the amount of gas volumes utilized by Columbia's default sales service customers.

Q. Please describe the general nature of gas distribution costs.

A. The delivery service costs of a gas distribution utility[2] are primarily fixed costs. Gas utilities design and install a gas distribution system capable of meeting its customers' design day requirements at the time of initial installation. Placing these facilities in service permits the utility to serve the changes in load due to extreme weather (i.e., the design day load). Once facilities serve customers, the costs associated with these facilities are by their nature fixed and do not vary as a function of the volume of gas consumed by customers.

Q. Is the fixed nature of these costs widely recognized?

A. Yes. The evidence supporting the fixed nature of these costs is quite significant. For example, utilities routinely normalize for weather both the costs and revenues of a gas utility as part of its rate case. If the costs of distribution mains were in any way related to the volume of gas consumed, it would also be necessary to weather normalize the utility's rate base, but this is not the case. It is widely recognized that the costs of distribution mains are fixed and do not vary with gas volume. Additionally, the Gas Distribution Rate Design Manual, prepared by the National Association of Regulatory Utility Commissioners ("NARUC") Staff Subcommittee on Gas,[3] defines demand or capacity costs as follows:

> Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during

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[2] Delivery service costs are the non-gas costs incurred by the utility to move gas volumes from its city-gates to customers' premises.

[3] Gas Distribution Rate Design Manual at pg. 23-24, Prepared by NARUC Staff Subcommittee on Gas, Published by National Association of Regulatory Utility Commissioners, June 1989.

> short intervals and do not directly vary with the number of customers or their annual usage. [Generally speaking, for a gas utility these costs can consist of]: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of the distribution plant not allocated to [the customer cost category], such as the costs associated with distribution mains in excess of the minimum size.

Q. Please discuss the factors that can influence the overall cost allocation framework utilized by a gas distribution utility.

A. Three standard steps or phases are followed when performing a COSS: cost functionalization, cost classification and cost allocation. The factors affecting these steps can include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the gas utility.

The physical configuration of the utility's gas system refers to considerations such as: (1) the transmission and/or distribution system configuration; (2) the mainline pipeline functionality; (3) the system operating pressure configuration; and (4) the existence of any production-related facilities. These considerations include determining whether: (1) the distribution system is a centralized grid/single city-gate or a dispersed/multiple city-gate configuration; (2) the gas utility has an integrated transmission and distribution system or a distribution-only operation; (3) the system operates under a multiple-pressure based or a single-pressure based configuration; and (4) the production-related facilities are used to support the peak demand or seasonal/annual demand requirements of the gas utility's customers.

Regarding data availability, the structure of the gas utility's books and records can influence its COSS framework. This structure relates to attributes such as the level of detail, segregation of data by customer or rate class, operating unit or geographic region, and the types of load data available.

State regulatory policies and requirements refer to the particular approaches used to establish utility rates in the state jurisdiction. For example, any specific methodological preferences or guidelines for performing COSS or designing rates established by the state regulatory body can affect the specific cost allocation method presented by the gas utility.

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

A. Regarding the physical configuration of Columbia's gas system, it is a combination concentrated (e.g., Columbus and Toledo) and dispersed, multiple city-gate gas distribution system, with a multi pressure-based system.

With respect to data availability, Columbia has detailed plant accounting records. Where necessary, it is a customary and accepted practice in the utility industry to rely upon current operating cost experience to derive reasonable cost estimates of customer-related facilities (e.g., services, meters and regulators) by rate class for purposes of assigning the test period costs of those facilities to the utility's rate classes.

Finally, the Commission's Standard Filing Requirements for Rate Increases specify that electric and gas utilities shall select at least one cost-of-service study methodology from: (i) Coincident peak demand; (ii) Non-coincident peak demand; or (iii) Average and excess. The selection shall be the utility's opinion of the most appropriate for its system characteristics.[4]

Q. What steps did you follow to perform Columbia's COSS?

A. I followed three broad steps to perform Columbia's COSS: (1) functionalization; (2) classification; and (3) allocation. The first step, the functionalization process, involves separating rate base (primarily plant in service) and expense items into operational components based on the various characteristics of utility operation. For Columbia, the functional cost category associated with gas delivery service consists of the distribution function.

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

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

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[4] Appendix A, Chapter 4901-7, Ohio Administrative Code, Standard Filing Requirements for Rate Increases, Page 118 of 165, Section E Instructions, Rates and Tariffs, Part (B)(5)(a).

Q. What objective are you seeking to achieve through this three-step process?

A. The functionalization and classification of the utility's total cost of service (i.e., its total revenue requirement) provides the cost analyst with groupings of costs that are fairly homogeneous, which enables the identification and application of cost allocation methods that have a closer relationship to the causation of the costs that are being assigned to the utility's rate classes.

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

A. To establish these relationships, the cost analyst must analyze the utility's gas system design and operations, its accounting records, and its system-wide and customer specific load data. From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all the utility's plant and expense elements.

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

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

Direct assignment of plant and expenses to specific customers or classes of customers is made based on special studies wherever the necessary data is 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 use facilities. Where a utility provides gas delivery services to two or more rate classes wherein one class uses fungible capacity which could be utilized by the other rate class, common costs are involved. This situation is illustrated through the utility's use of its gas distribution mains to serve multiple rate classes and a wide range of customers within these classes. As a result, to the extent a utility's plant and expenses cannot be directly assigned to customer groups, "common" allocation methods must be derived to assign or allocate the costs to the customer classes. The types of analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. As part of your work, did you review Columbia's gas system design and operations?

A. Yes. Since it is widely recognized that a utility's plant-in-service components directly support a utility's gas system and its customers' service requirements, I initially focused my efforts on better understanding the nature and operation of Columbia's gas system. This effort included review of the design and operating characteristics of its gas distribution system and the types and levels of costs incurred in connecting various sized customers to its gas distribution system.

Q. Please explain the most important considerations you relied upon in determining the cost allocation methodologies that were used to conduct Columbia's COSS.

A. As stated above, it is important to recognize the cost causative characteristics of each of the cost elements that are to be directly assigned or allocated within any class cost of service study. Additionally, the cost analyst needs to structure data in the COSS in a format (e.g., by cost classification and function) that is supportive of the appropriate allocation of costs to the utility's customer or rate classes. Of further concern is the availability of data for use in developing alternative cost allocation factors. In evaluating any cost allocation methodology, consideration should be given to:

1. Recognition of cost causality as opposed to value of service;
2. Results that are representative of the true costs of serving different types of customers;
3. A sound rationale or theoretical basis;
4. Stability of results over time;
5. Logical consistency and completeness; and
6. Ease of implementation.

Q. Please explain the overall approach and guidelines you used to conduct Columbia's COSS.

A. Throughout the process of choosing cost allocation methods and deriving cost allocation factors for use in a utility's COSS, I always objectively determine cost causative factors that are grounded in the design and operating characteristics of the specific utility. This was also the case in conducting the COSS filed by Columbia in this proceeding. As a result, Columbia's COSS reasonably reflects the appropriate cost causation characteristics across all its rate classes and derives results that objectively portray the true costs to serve each of the utility's rate classes and the customers within each rate class. These results can be used with confidence as a guide to establish Columbia's class revenues and rates in this proceeding.

Q. Please describe the key issues related to the allocation of demand-related costs within a gas utility's COSS.

A. An important and complex part of the allocation process is the allocation of demand-related costs. These costs represent a relatively large portion of the utility's total revenue requirements, and the plant facilities and expenses are joint in nature, meaning that "common" allocation methods must be used instead of direct assignments. Several methodologies have been used to develop allocation factors for the demand components of costs. As discussed above, these three methodologies authorized by the Commission's Standard Filing Requirements are the Coincident Peak Demand Allocation Method, the Average and Excess Demand Allocation Method and the Non-Coincident Demand Allocation Method. Each of these demand allocation methodologies is discussed below.

The concept of the Coincident Peak Demand Allocation Method is premised on the notion that investment in capacity is determined by the peak load or peak loads of the gas utility. Under this methodology, demand-related costs are allocated to each customer class or group in proportion to the demand coincident with the system peak or peaks of that class or group relative to the system peak. The Coincident Peak Demand Allocation process might focus on a single peak such as the utility's design day which is based on the worst-case temperature conditions under which the utility's gas distribution system must be designed. Other variations might include the average of several cold days, or the expected contribution to the system peak on a design day.

The Average and Excess Demand Allocation Method, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service based on system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated based on each class's average demand. The portion of these facilities 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 (i.e., total class non-coincident demand minus average demand). A more simplistic version of this methodology is the Peak and Average methodology. This cost methodology gives equal weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's demand-related costs on a commodity-related basis.

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

Q. How have demand-related costs been allocated in Columbia's COSS?

A. Columbia's COSS uses a coincident peak demand (derived on a design day basis) to allocate demand-related costs to its rate classes. Demand-related costs for Columbia consist of the capacity costs (plant-related and expenses) associated with its city-gate facilities and the capacity or demand-related portion of its gas distribution system.

Q. Why doesn't Columbia use average demand (i.e., annual throughput volumes divided by 365 days) to allocate demand-related costs?

A. Using only average demand to allocate demand related costs is inappropriate because it does not reflect the cost causative characteristics of demand-related costs. If a gas utility's system were sized and installed to accommodate average gas demands, it would be unable to accommodate the design day demands upon which the system was built. That is, by sizing plant investment for design day demands, the gas utility is assured of being able to satisfy its service obligation throughout the year. From a gas engineering perspective, a design day demand criterion is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system. As such, cost causation with respect to demand-related costs is unrelated to average demand characteristics.

Additionally, use of average demand characteristics for the allocation of demand-related costs penalizes customers that exhibit efficient gas consumption characteristics (i.e., customers with high load factors) and encourages the inefficient use of the gas utility's system by customers with low load factors.

For the above-stated reasons, it is inappropriate to solely rely upon a commodity-based allocation factor, as derived from annual gas throughput volumes, for purposes of allocating demand related costs to a gas utility.

Q. Why did you choose to utilize Columbia's design day demands rather than its actual peak day demands as a demand allocation factor?

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

1. A gas utility's system is designed, and consequently costs are incurred, to meet its design day demand. In contrast, costs are not incurred on the basis of an average of peak demands over time.
2. Design day demand is directly related to the level of change in customers' maximum daily demands for gas and to the associated change in fixed plant investment over time.
3. Design day demand provides more stable cost allocation results over time.

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

A. Columbia must consistently rely upon design day demand in the design of its own distribution facilities required to serve its firm service customers. This requirement will ensure that the utility has sufficient gas distribution system capacity to continue to provide reliable gas service during design day (worst case) conditions. And perhaps more importantly, design day demand directly measures the gas demand requirements of Columbia's firm service customers which create the need for it to acquire resources, build facilities and incur hundreds of millions of dollars in fixed costs on an ongoing basis. Based on my experience, there is no better way to capture the true cost causative factors of Columbia's gas operations than to utilize its design day demand requirements within its COSS.

Q. What level of firm demand requirements must Columbia consider in designing its gas distribution system to deliver under all conditions?

A. It is my understanding that Columbia designs its gas system, and has sufficient capacity, to serve the maximum delivery service requirements of all its firm sales and transportation service customers. I would consider this to be a reasonable approach, and one that is common across the gas utility industry. Therefore, the demands of all firm customers will be treated on an equivalent basis for purposes of cost allocation based on using the design day demands of Columbia's rate classes.

Q. Why is the use of design day demands closely related to the change in Columbia's fixed plant investment over time?

A. Changes in design day demands serve as the primary input into Columbia's ongoing decisions to install distribution system facilities to meet firm customer demands for gas delivery service. Simply stated, when customers' design day demands increase to a certain point, Columbia needs to consider additional fixed plant investments, as it needs to be able to meet its design day demands.

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

A. A gas utility's design day demand is the primary determinant of its planned capacity requirements and utilization. As described earlier, the design day demand is a measure of firm customers' maximum daily gas usage under pre-defined, worst-case weather conditions. As such, design day demand will not vary to the same degree as the utility's actual peak day demands, because those demands can increase or decrease in any year compared to the peak day demands experienced in past years based on whether the specific day was relatively colder or warmer. Therefore, use of design day demand provides a more stable basis, and one more tied to the basis of investment decisions, than any of the other demand allocators available based on either actual peak day demand or the averaging of multiple peak day demands.

Q. In addition to the allocation of demand-related costs, are there any other aspects of a gas utility's COSS worthy of focus?

A. Yes. Another critical element of a gas utility's COSS is the cost classification, allocation methods, and related allocation factors used to assign the plant and expenses associated with distribution mains to the utility's classes of service.

Q. Please describe the system operating conditions that provide a foundation for the choice of classification and allocation methods for the costs of distribution mains.

A. Gas customers in a utility's residential and commercial service classes have exhibited declining use per customer due to the improved efficiency of capital stock replacement and improvements to the housing thermal envelope. This improved efficiency over time lowers the utility's design day requirements compared to the design day requirements at the time when the original plant was designed and installed to serve customer loads. As a result, the growth in distribution plant for gas customers primarily reflects the growth in number of customers using gas service. That is, a utility's system of distribution mains must be extended over time to permit new customers to receive gas service. Therefore, the primary driver of new distribution mains cost is the addition of new customers. Further, there are substantial economies of scale associated with the gas distribution infrastructure such that the unit cost of capacity for gas delivery declines with size at a relatively rapid rate.

Q. Please discuss the economies of scale associated with gas distribution service.

A. Scale economies for a gas distribution utility reflect the relationship between the installed cost of pipe by size and type, coupled with the increased capacity from pressure and pipe diameter. For example, doubling the size of the gas main results in more than a doubling of the available capacity of the main, at a cost for Columbia that is less than double the cost of the smaller size main. For a lower pressure system, increasing pipe size from two-inch to four-inch allows almost six times the amount of gas to flow. In general, the cost causative characteristics associated with the economies of scale result in larger customers imposing lower unit costs of design day capacity on the gas utility's distribution system than do smaller customers.

Q. Can you please explain how the costs of gas distribution mains should be classified and allocated in a gas utility's COSS?

A. Yes. There are two cost factors that influence the level of distribution main facilities installed by a gas utility in expanding its gas distribution system. First, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid over time to connect new customers to the system. Secondly, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the coincident peak gas demand placed on the gas utility's system by its firm customers. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment and the related operation and maintenance ("O&M") expenses based on both the number of customers served by the gas utility and its design day demands.

To further explain, the customer component of distribution mains is premised upon the concept of a "minimum system." The "minimum system" for a gas distribution utility is the smallest hypothetical system a gas utility would construct to connect its customers. The classification of the costs associated with the minimum system as customer-related, rather than capacity-related, recognizes the fact that the gas utility must install a network of distribution mains simply to have a physical connection with its customers, regardless of the level of demand a specific customer will actually impose on the gas system. A customer cannot be served at any level if the customer is not physically interconnected with the utility's gas distribution system.

Using the minimum system concept as a foundation, it is widely recognized that a large portion of a gas utility's total cost of distribution mains must be borne regardless of customers' peak day or annual use. To illustrate this point, it is useful to summarize a gas utility's process for physically connecting new customers. To extend gas service to a typical residential subdivision, the utility must first design the gas system. Based on this design, the utility determines the length and size of pipe needed to serve the area and procures the necessary material. A field crew is then dispatched to the site, together with the materials and equipment required to install the natural gas facilities. The activities necessary to install gas mains include digging a trench, installing the main into the trench, and backfilling the trench. Pipeline boring (i.e., a trenchless installation method) may be necessary to install some main segments if the utility is unable to open trench a portion of the line due to existing surface conditions along the route of the main. After the main is installed, it will be pressure tested, tied into the existing gas system, and purged and filled with natural gas. The main is then ready to provide utility service to the new customers. These steps are necessary regardless of how much gas the new customers are projected to use during the year or during a peak day. The design work must still be completed, the crews, materials, and equipment dispatched to the site, the trench dug, the main installed in the trench, the trench backfilled, testing performed, and the other activities performed.

The additional costs associated with any larger mains required are mostly the incremental costs of the larger mains themselves, the additional labor involved with digging a wider trench for very large mains, and possibly the need for additional equipment to handle larger diameter pipe. As a result, a large percentage of the costs of providing gas delivery service to a gas utility's customers are incurred before they ever use one unit of gas. These are the costs the gas utility must incur simply to extend its gas distribution system to customers, irrespective of whether they will demand a small or large volume of gas on a peak day. As a result, the costs of such a minimum system are fundamentally customer-related in nature.

Q. What methods are used in the gas utility industry to determine the customer component of distribution mains?

A. Based on my experience, the two most commonly used methods in the gas utility industry for determining the customer cost component of distribution mains facilities consist of: (1) the zero-intercept method; and (2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept method, which is the method utilized in Columbia's COSS, a customer cost component is developed through statistical regression analyses to determine the unit cost (i.e., cost per foot) associated with a zero-inch diameter distribution main. This concept can also be thought of as estimating the fixed costs per foot that the utility incurs to design and install a gas distribution main regardless of the main's diameter.

The most commonly installed, minimum-sized unit method is intended to reflect the engineering considerations associated with installing distribution mains to serve the utility's gas customers. That is, this method utilizes actual installed investment units to determine the minimum gas distribution system rather than a statistical analysis based upon investment characteristics of the utility's entire gas distribution system.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies are Electric Utility Cost Allocation Manual, by John J. Doran et al., NARUC[5] and Gas Rate Fundamentals, American Gas Association.[6] Both these authorities describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities. In its publication, "Gas Distribution Rate Design Manual," NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment. Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. Have you prepared an analysis that supports Columbia's classification and allocation of distribution mains costs?

A. Yes. The COSS workpapers filed by Columbia, which present details of the derivation of external allocation factors, provide the derivation of the customer cost component of distribution mains for Columbia using the zero-intercept method based on Columbia's historical costs of distribution mains, adjusted to current cost levels using the Handy Whitman index. The resulting percentage of 55.36% represents the customer cost component of distribution mains and the remaining 44.64% represents the demand cost component.

The customer cost component is then allocated to Columbia's rate classes based on the number of customers in each rate class for the test year, and the demand cost component is allocated to the rate classes based on the design day demand allocation factor.

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[5] Doran, John J. Frederick M. Hoppe, Robert Koger, William W. Lindsay, Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, Washington D.C., 1973.

[6] Gas Rate Fundamentals, American Gas Association Rate Committee, Fourth Edition, 1987.

Q. Earlier in your testimony you discussed the use of special studies to assign plant and expenses to a utility's rate classes. Please describe the special studies you conducted to assign Columbia's other distribution plant investment to its rate classes.

A. Regarding Columbia's major plant accounts, a series of direct assignments were developed to allocate the following plant accounts: Services - Account No. 380, Meters - Account No. 381, Meter Installations - Account No. 382, House Regulators – Account No. 383, and Industrial Measuring & Regulating Station Equipment - Account No. 385. In particular, the special studies reflect the differences in the unit costs that specific customer groups cause Columbia to incur to provide gas delivery service to its customers.

Q. How was general plant allocated in Columbia's COSS?

A. The general plant accounts (Account Nos. 389-398) are composed of facilities and equipment that primarily support Columbia's labor force in the day-to-day gas utility operations. On that basis, each account was allocated to Columbia's rate classes using a composite allocation factor based on its total labor expenses.

Q. How was intangible plant allocated in Columbia's COSS?

A. Intangible plant primarily consists of Miscellaneous Intangible Plant (Account No. 303), which includes a variety of computer software investments that support Columbia's customer billing, financial, and accounting functions on a corporate basis. The investment costs associated with the customer billing and accounting functions were allocated to Columbia's rate classes using the number of bills in each rate class. All other software investment costs associated with the corporate-wide financial and accounting functions were allocated to the rate classes using a general composite allocation factor based on an equal weighting of plant in service and O&M expenses.

Q. Please describe the method used to allocate Columbia's reserve for depreciation and depreciation expenses.

A. These items were allocated to Columbia's rate classes on the same basis as their associated plant accounts.

Q. How were distribution-related O&M expenses allocated in Columbia's COSS?

A. In general, these expenses were allocated to Columbia's rate classes based on the cost allocation methods used for Columbia's corresponding plant accounts. A utility's O&M expenses generally are considered to support the utility's corresponding plant-in-service accounts. That is, the existence of the specific 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 specific plant account will be the same basis as used to allocate the corresponding expense account. For example, Maintenance of Services - Account No. 892, is allocated on the same basis as its investment in Services - Account No. 380. With Columbia's detailed analyses supporting its assignment of 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.

Q. How were Customer Account Expenses allocated in Columbia's COSS?

A. I understand that virtually all of Columbia's customers have their meters read and bills created using identical automated methods that rely upon the same systems and staff resources. As a result, there is little, if any, difference in the unit costs incurred by Columbia to read meters and bill its customers, regardless of their class or service categorization. To reflect these similar cost characteristics, the expenses in Account Nos. 901 through 905 (excluding Uncollectible accounts expense) were allocated based on the number of bills in each rate class. Finally, Uncollectible accounts expense (Account No. 904) was directly assigned to the LGS/LGTS/FRLGTS rate class to reflect the fact that Columbia's Uncollectible Expense ("UEX") Rider is charged only to its SGS/SGTS/FRSGTS and GS/GTS/FRGTS customers and that UEX revenues and expenses have been excluded from Columbia's base rate revenue requirement.

Q. How were Customer Service and Information Expenses and Sales Expenses allocated in Columbia's COSS?

A. Customer Assistance Expenses (Account No. 908) was allocated to Columbia's rate classes based on an analysis of the specific activities and related costs to determine if there was a specific customer group, or groups (residential, commercial and industrial) that required each type of activity. Based on this analysis, it was determined that the costs of Columbia's WarmChoice® program should be directly assigned to its SGS/SGTS/FRSGTS rate class for recovery through base rates.[7] The balance

[7] The remainder of Columbia's Demand Side Management ("DSM") Rider revenues and expenses were excluded from Columbia's base rate revenue requirement.

of this Account and Informational and Instructional Expense and Other Expenses (Account Nos. 909 and 910) was allocated to each rate class based on the number of bills.

Q. How were Administrative and General ("A&G") expenses allocated in Columbia's COSS?

A. Columbia's COSS allocated these expenses to its rate classes on a specific account-by-account basis rather than on an aggregate basis. Specifically, the A&G expenses of a utility typically pertain to the following expense categories: (1) labor; (2) plant or rate base; and (3) O&M expenses. In Columbia's COSS, each of its A&G accounts was related to one or more of these categories. These categories were then used as a basis to establish an appropriate allocation factor for each account. The allocation factors chosen were broad-based to specifically recognize the corporate-wide nature of A&G expenses.

Specifically, Administrative and General Salaries (Account No. 920), Office Supplies and Expenses (Account No. 921), Administrative Expenses Transferred (Account No. 922), Injuries and Damages (Account No. 925), Employee Pensions and Benefits (Account No. 926) and Rents (Account No. 930) were allocated using a labor-based allocation factor derived from the labor component of Columbia's distribution O&M expenses. Similarly, the plant and O&M allocation factors discussed above were derived based on Columbia's total plant investment and total O&M expenses, respectively. Property Insurance (Account No. 924) was allocated on total plant in service. Outside Services (Account No. 923) and Miscellaneous Expenses (Account No. 930.2) include support activities provided to Columbia directly by outside service providers and its corporate parent organization. These activities relate to various general business functions that support Columbia's gas utility operations. Due to the general nature of these costs and their corporate-wide applicability, these costs were allocated to Columbia's rate classes using a composite allocation factor based on an equal weighting of total plant in service and O&M expenses (excluding purchased gas costs). Finally, Regulatory Commission Expenses (Account No. 928) was allocated to the rate classes using a non-gas revenue allocation factor.

Q. Please describe the method used to allocate Columbia's amortization expenses.

A. Each amortization category was allocated to Columbia's rate classes based on the specific nature of the deferral amount. The amortization for Deferred

Depreciation was allocated to the rate classes on the same basis as Depreciation Expenses. The amortization of Post-in-Service Carrying Costs and Environmental Costs were allocated to the rate classes based on total plant in service.

Q. How were taxes other than income taxes allocated in Columbia's COSS?

A. These expenses were allocated in Columbia's COSS in a manner to reflect the cost causative factors associated with Columbia's specific tax expense categories. Specifically, these taxes can be cost classified based on the tax assessment method established for each tax category (i.e., property). As a result, taxes other than income taxes of a utility typically can be grouped into the three categories of plant, labor expenses, and revenues. In the filed COSS, each of Columbia's accounts for taxes other than income taxes was related to one of the above-stated categories. These categories were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. How were income taxes allocated in Columbia's COSS?

A. Income Taxes were allocated to each rate class based on each class' income before federal income taxes. This approach made certain that the income tax assigned to each rate class reflected the proper weighting of class revenues, previously allocated expenses, and the various adjustments made by Columbia for tax computation purposes. The increases in income taxes associated with revenues producing equal class rates of return, and at proposed revenues, were computed and allocated to each rate class on a similar basis to account for the class' revenues and allocated expenses so that the amounts equaled the income taxes at proposed rates included in Columbia's total revenue requirement.

V. RESULTS OF COLUMBIA'S COSS

Q. Please discuss the results of Columbia's COSS.

A. Referring to Schedule E-3.2-1 of Columbia's COSS indicates that at current rates during the test year, its rate classes are contributing to the recovery of Columbia's total revenue requirement as follows:

- The SGS/SGTS/FRSGTS rate class exhibits a lower than average rate of return on net rate base.
- The GS/GTS/FRGTS rate class exhibits a higher than average rate of return on net rate base.

- The LGS/LGTS/FRLGTS rate class exhibits a higher than average rate of return on net rate base.
- The FRCTS rate class exhibits a higher than average rate of return on net rate base.

Q. Please summarize the results of Columbia's COSS.

A. Table 1 below presents a summary of the results of Columbia's COSS that I described above at current revenue and rate levels. Schedule A-1, which Columbia filed as part of its application in these cases, shows an overall revenue deficiency for Columbia of approximately $221.4 million.

Table 1 – Summary Results of Columbia's COSS at Current Rates[8]

Rate Class	Operating Income	Rate of Return on Net Rate Base	Relative Rate of Return
SGS/SGTS/FRSGTS	$30,072,944	0.97%	0.33
GS/GTS/FRGTS	$58,707,276	19.21%	6.54
LGS/LGTS/FRLGTS	$15,665,864	11.32%	3.85
FRCTS	$106,998	8.02%	2.73
Total	$104,553,082	2.94%	1.00

Rate of Return on Net Rate Base is calculated by dividing operating income for each rate class by the net rate base for that class. Relative Rate of Return is calculated by dividing the Rate of Return on Net Rate Base for each rate class by the Total Rate of Return on Net Rate Base. Regarding rate class revenue levels, the rate of return results show that certain rate classes are being charged rates that recover less than their indicated costs of service. As a result, rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. I will explain next how these COSS results were used to guide Columbia's determination of the revenues by rate class at proposed rate levels.

Q. How can COSS results such as these provide guidelines for rate design?

A. Results of a COSS provide cost guidelines for use in evaluating class revenue levels and class rate structures. By adjusting rates in accordance with the cost study, rate class revenue levels can be brought closer in line with the indicated costs of service resulting in movement of rate class rates of

[8] See Schedule E-3.2-1, page 1 of 4, lines 23 through 25.

return toward the system average rate of return and resulting in rates that are more in line with the cost of providing service. At the same time, though, it is recognized that there are non-cost factors such as customer impact considerations (e.g., avoiding rate shock through gradualism) and rate continuity that are often balanced with the cost to serve in apportioning the utility's proposed revenue increase among its rate classes.

Concerning cost justification of rates within each rate class, the classified costs, as allocated to each class of service in the cost study, provide cost information that can be of assistance in determining the need for changes in the relative levels of demand, customer, and commodity rate block charges.

Q. Please explain how the unit cost results presented in Schedule E-3.2-2 were prepared.

A. Black & Veatch's Gas Cost of Service Study Model compiles the functionalized, classified, and allocated expenses and rate base data for each class of service. The system average rate of return is applied to the allocated rate base to determine the required net income. This amount is then grossed up to account for the income tax related revenue responsibilities. The sum of the expense related revenue requirement and the rate base related revenue requirement yields the total revenue requirement for each component of cost at the system average rate of return. The computer model makes this calculation for each of the various cost components (i.e., the demand, customer, and commodity portions of the purchased gas and distribution functional categories). The functionally classified costs are unitized by dividing the total costs by the appropriate number of billing units. Customer-related costs are divided by the number of bills, demand-related costs are divided by the contribution to design day demand, and commodity-related costs are divided by the number of Mcf delivered. It should be noted that a monthly customer cost is calculated for each customer class, as well as unit commodity and demand costs.

Q. Can these unit cost analysis results be used for rate design?

A. Yes, if three part rates (i.e., customer, demand, and commodity) were set at the unit cost levels, Columbia's operating expenses and rate of return on investment based on its pro-forma test year would be recovered (assuming customer counts, gas deliveries, and other billing determinants were as projected). The unit cost analyses also provide valuable unbundled cost information for the design of portions of the tariffs. One of the most obvious applications is the use of unbundled cost information for establishing cost-based customer charges. The unit cost analysis could also be used to establish separately metered contract demand charges where the cost of demand metering can be justified or where a reasonable method of estimating customer demands can be derived.

VI. COLUMBIA'S PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Columbia's proposed revenue increase of $221.4 million to its various rate classes.

A. As described earlier, the apportionment of revenues among rate 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 current revenue levels; and (3) customer impact considerations, such as rate shock. These criteria were evaluated for each of Columbia's rate classes. Based on this evaluation, adjustments to the current revenue levels in all rate classes were made so that the rates proposed by Columbia moved class revenues closer to the costs of serving those rate classes. Importantly, Columbia's revenue adjustments were not determined based on a desired outcome, but instead were derived based on a careful and balanced evaluation of the chosen criteria.

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

A. Yes. Using Columbia's proposed revenue increase, and the results from its COSS, I evaluated various options for the assignment of that increase among its rate classes and, in conjunction with Columbia, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. Those discussions addressed each of the criteria I listed above to find an interclass revenue proposal that reasonably balanced these criteria. Schedule E-3.2-1 summarizes the COSS-related computations supporting Columbia's class revenue apportionment process. Attachment RAF-2 also provides details of Columbia's class revenue apportionment process together with the computational details supporting its proposed rate design for each rate class.

The first benchmark option that I evaluated under Columbia's proposed non-gas revenue level was to adjust the revenue level for each rate class so that the relative rate of return on net rate base for each class was equal to 1.00. Page 3 of Schedule E-3.2-1 (lines 45-46 and 62-63) provides these results. Based on my experience, I determined that this fully cost-based option was not the preferred solution to the interclass revenue issue due to its significant changes in class revenue levels. It should be pointed out, however, that those results represented an important guide for purposes of evaluating subsequent rate design options from a strict cost of service perspective.

The second option I considered was assigning the increase in revenues to Columbia's rate classes based on an equal percentage of its current non-gas revenues. Page 4 of Schedule E-3.2-1 (lines 71-72) provides these results. This option resulted in each rate class receiving an increase in revenues. However, when this option was evaluated against the COSS results (as measured by changes in the rate of return on net rate base for each rate class), there was only modest movement towards cost for certain of Columbia's rate classes.[9] This result indicated that class revenues were not moving towards the cost of service in a sufficiently meaningful manner under this option. While this option also was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a general range of results that provided me with further guidance to help develop Columbia's class revenue apportionment proposal.

Q. What was the next step in the process of determining Columbia's interclass revenue proposal?

A. After discussions with Columbia concerning the costs of serving each rate class and the relative rate impacts of the various class revenue options described above, it was concluded that an appropriate interclass revenue proposal would generally assign a greater than average increase to each rate class that exhibited a greater revenue subsidy relative to the cost to serve the rate class, as derived in Columbia's COSS. Each of these rate classes exhibits a relative rate of return on net rate base below 1.00 at current rates under Columbia's COSS (see Table 1 above). For each rate class that exhibited a revenue excess or a relative rate of return on net rate base above 1.00, it was determined that a smaller than average increase in non-gas revenues was warranted.

This approach resulted in reasonable movement of the class relative rates of return on net rate base towards unity or 1.00. That result is reflected on Schedule E-3.2-1, page 2 of 4 (lines 40-43), wherein the relative rates of return on net

[9] See Schedule E-3.2-1, page 4, line 79.

rate base are shown to converge towards unity or 1.00 compared to the same measure calculated under present rates. In addition, the amounts of the existing rate subsidies and excesses among Columbia's rate classes were materially reduced. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable to move class revenues and rates closer to the indicated cost of service for each rate class. Table 2 below summarizes the proposed change in revenue (excluding Other Revenue) for each rate class and the percent change from revenues at current rates resulting from the above-described process. Attachment RAF-2, page 6 of 10 provides the computational details for the proposed class revenue apportionment and percent change by rate class summarized in Table 2.

Table 2 – Proposed Revenue Apportionment by Rate Class[10]

Rate Class	Revenues at Current Rates	Relative Rate of Return	Revenue Change	Percent Change	Relative Rate of Return
SGS/SGTS/FRSGTS	$646,025,662	0.33	$202,747,579	31.4%	0.78
GS/GTS/FRGTS	$112,625,547	6.54	$12,835,573	11.4%	2.87
LGS/LGTS/FRLGTS	$38,923,488	3.85	$5,880,449	15.1%	1.87
FRCTS	$291,547	2.73	$36,657	12.6%	1.30
Total	$797,866,244	1.00	$221,500,258	27.8%	1.00

Q. Have you prepared a detailed comparison of Columbia's current and proposed revenues by rate class?

A. Yes. Schedule E-4 presents a detailed comparison of current and proposed revenues for each of Columbia's rate classes. This Schedule is a multiple page summary of revenue and current and proposed rates by individual rate schedule and revenue class. The source of information for these schedules is Schedule E-4.1, with the exception of revenue amounts from Columbia's competitively priced customers the source of which is Columbia's WPE-4e through WPE-4i work papers, and "Other Revenue," which is sourced from Columbia's C Schedules.

Q. Please describe Schedule E-4.1.

A. Schedule E-4.1 presents the derivation of Columbia's annualized revenue at current and proposed rates by revenue class under each rate schedule.

[10] See Schedule E-3.2-1, page 1 of 4, line 13 (excluding Other Revenue) and page 2, lines 33-34 and line 41.

Q. Please describe the format used by Columbia to prepare Schedule E-4.1.

A. Schedule E-4.1 consists of 78 pages with revenue at current rates derived on the odd numbered pages and revenue at proposed rates derived on the even numbered pages. Those pages that present revenue at current rates show the applicable rate schedule; number of bills; throughput at the various rate block breakpoints; most current rates; revenue at most current rates; percent of revenue to total revenue excluding gas costs; revenue increase requested; percent of revenue increase less gas costs; gas costs revenue where applicable; total revenues at current rates; and total revenue percent of increase. Those pages that present revenue at proposed rates show the applicable rate schedule; number of bills; throughput at the various rate block breakpoints; proposed rates; revenue at proposed rates; percent of revenue to total revenue excluding gas cost revenue; gas costs revenue where applicable; and total revenue at proposed rates.

VII. COLUMBIA'S PROPOSED RATE DESIGN

Q. Please describe the key objectives you sought to achieve in the design of Columbia's proposed rates.

A. In general, I sought to achieve the following objectives with the rate design that is proposed for Columbia:

- Achieve fair and equitable rate levels (reflective of the cost to serve).
- Avoid undue discrimination between and within rate classes.
- Rates should be stable, understandable, and provide customer choices.
- Create economically efficient pricing for natural gas delivery service.
- Rates should encourage energy conservation and energy efficiency.
- Rates should allow a utility to recover its revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.

As an overarching principle, Columbia also has consistently supported a rate design framework under which the fixed costs of its gas distribution system are recovered through fixed charges, to the extent practical. And as I discuss in further detail later in my direct testimony, the Commission has a long history of embracing this principle as evidenced most directly through its continued approval of a Straight Fixed-Variable ("SFV") rate design for the smaller residential and general service customers served by the gas distribution utilities in Ohio. Consistent with this principle, the Commission-approved costs in Columbia's Infrastructure Replacement Program ("IRP")

Rider and Capital Expenditure Program Rider ("CEP Rider") are recovered monthly from its customers on a fixed charge basis.

Among other things, fixed charges promote fairness to all customers because the customer's bill reflects the actual average cost of providing gas delivery service rather than being based on the volume of gas consumed. Columbia's current SFV rate design for its SGS/SGTS/FRSGTS rate class and the fixed rate recovery under its IRP and CEP Riders are consistent with, and supportive of, this important utility ratemaking objective.

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

A. Columbia has proposed the following rate design changes to its sales and transportation rate schedules:

1. A change in the annual volumetric breakpoint between the SGS/SGTS/FRSGTS and GS/GTS/FRGTS rate classes from 300 Mcf per year to 600 Mcf per year.[11]
2. An increase in the current Monthly Delivery Charge for the SGS/SGTS/FRSGTS rate class to reflect the level of fixed distribution costs incurred by Columbia to serve customers in this rate class.
3. An increase in the current monthly Customer Charges for the GS/GTS/FRGTS and LGS/LGTS/FRLGTS rate classes to reflect the level of fixed distribution costs incurred by Columbia to serve customers in these rate classes and to recognize the fixed charges currently being paid monthly by these customers through the IRP and CEP Riders.
4. Establishment of a Monthly Delivery Charge for the FRCTS rate class.
5. Elimination of the current Mainline Delivery Charge under the LGTS rate schedule.
6. Elimination of the current tariff provision in the LGS/LGTS/FRLGTS rate class which requires that at least 50% of a customer's annual consumption must be consumed in the seven billing months

[11] Service under Columbia's SGS/SGTS/FRSGTS rate schedules is currently available to all customer accounts that consume less than 300 Mcf per year, and service under its GS/GTS/FRGTS rate schedules is currently available to all customer accounts that consume at least 300 Mcf per year.

of April through October to qualify for service under these rate schedules.

I will present the specific rate structure changes and supporting rationale for each of Columbia's rate classes later in my direct testimony.

Q. Please explain why Columbia has proposed to change the volumetric breakpoint between the SGS/SGTS/FRSGTS and GS/GTS/FRGTS rate classes.

A. This proposed change to the rate schedule applicability provisions for the SGS/SGTS/FRSGTS and GS/GTS/FRGTS rate classes was made by Columbia to help minimize the number of customers who are transferred each year between these rate classes based on changes in their annual consumption levels that are identified during Columbia's Annual Consumption Review. With this proposed change, Columbia anticipates that fewer customers in these rate classes will experience a change in their designated rate schedule as an outcome of the Annual Consumption Review. This proposed change is expected to reduce the rate impacts experienced by these customers caused by periodic changes to the level of their gas bills when they are transferred to a new rate schedule.

Q. Can you briefly describe the Annual Consumption Review conducted by Columbia for its SGS/SGTS/FRSGTS and GS/GTS/FRGTS customers?

A. Yes. According to its current tariff, Columbia reviews the actual annual consumption of its sales service and transportation service customers for the thirty-six-month period ending each August 31st or October 31st billing cycle, respectively, in order to: (1) determine the rate schedule under which each customer qualifies to be served and if any customer transfers between rate schedules are needed; and (2) update each customer's annual volumes and winter/summer maximum daily quantities ("MDQ") for transportation service customers. Based on the results of this review process, certain customers are transferred each year to a new rate schedule based on changes in their annual consumption levels. Columbia contacts each of these customers in advance by letter to inform them of: (1) the results of Columbia's Annual Consumption Review; (2) the customer's updated gas consumption level; and (3) the change in rate schedule. Any necessary rate schedule changes for the SGS/SGTS/FRSGTS and GS/GTS/FRGTS customers become effective in October for billings beginning in November.

Q. How did Columbia conclude that the volumetric breakpoint should be changed from 300 Mcf per year to 600 Mcf per year in the SGS/SGTS/FRSGTS rate schedules?

A. Columbia conducted a review of its annual bill frequency data for a recent 12-month period for its SGS/SGTS/FRSGTS and GS/GTS/FRGTS customers and determined that there are fewer customers consuming between 550 Mcf and 650 Mcf per year in both rate classes compared to the number of customers consuming between 250 Mcf and 350 Mcf per year. These ranges fairly capture the annual variation in customer usage for these rate classes caused by a variety of factors, including changes in weather (i.e., temperature and HDDs). On that basis, it was concluded that increasing the volumetric breakpoint between the SGS/SGTS/FRSGTS and GS/GTS/FRGTS rate schedules from 300 to 600 Mcf per year was an appropriate change to minimize the annual number of customer transfers between the SGS/SGTS/FRSGTS and GS/GTS/FRGTS rate schedules.

Q. How has Columbia reflected this proposed change in its rate filing?

A. For purposes of this rate filing, Columbia has transferred approximately 17,000 customers who currently consume between 300 and 600 Mcf per year from its GS/GTS/FRGTS rate schedules to its SGS/SGTS/FRSGTS rate schedules.[12] These transfers were made to reflect the appropriate rate schedule for these customers and Columbia computed its proposed revenues and rates assuming these customers would be served under the SGS/SGTS/FRSGTS rate schedules. With this one-time transfer of customers, Columbia expects that it will greatly reduce in the future the number of customers in the SGS/SGTS/FRSGTS and GS/GTS/FRGTS rate classes who will have to be transferred each year to a new rate schedule.

Q. Please explain in general terms how Columbia's proposed Monthly Delivery Charges were derived in each rate class.[13]

A. While being cognizant of the rate design objectives I discussed earlier, Columbia's proposed Monthly Delivery Charges in each rate class were de-

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[12] See WPE-4a, column (5).

[13] Columbia distinguishes between its current monthly Customer Charges and its proposed Monthly Delivery Charges to recognize that its monthly Customer Charges are designed to recover the customer-related costs incurred to serve its customers, while its Monthly Delivery Charges are designed to also recover all or a portion of Columbia's other fixed distribution costs incurred to serve its customers (i.e., demand-related costs).

rived in specific consideration of: (1) the level of customer-related costs determined in Columbia's COSS; (2) the recovery of costs included in Columbia's IRP and CEP Riders on a monthly fixed basis; (3) the percentage by which the current non-gas revenues for the given rate class was proposed to change; and (4) the results of the bill comparisons which showed the impact of Columbia's current and proposed rates on the monthly gas bills of varying-sized customers in the given rate class.

Q. Have you summarized the customer-related costs derived in Columbia's COSS and the current fixed charges under its IRP and CEP riders and compared those cost levels to Columbia's current Monthly Delivery Charge or Customer Charges in each of its rate classes?

A. Yes. Attachment RAF-3 presents the customer-related costs based on the results of Columbia's COSS, as presented in Schedule E-3.1, the current fixed charges assessed to customers under its IRP and CEP Riders, and the current and proposed Monthly Delivery Charges and Customer Charges for each of Columbia's rate classes. Attachment RAF-3 shows that the levels of customer-related and other fixed infrastructure-related costs incurred by Columbia to serve customers in each of its rate classes are above the current levels of the Monthly Delivery Charges and Customer Charges.[14]

Q. Why is it appropriate to make this type of rate comparison in conjunction with setting the proposed level of Columbia's Monthly Delivery Charges and Customer Charges for each rate class?

A. Columbia's customers currently pay on a fixed charge basis each month for either all or a material portion of the costs of gas delivery service. These fixed charges consist of a combination of either a Monthly Delivery Charge (SGS/SGTS/FRGTS customers) or Customer Charges (GS/GTS/FRGTS and LGS/LGTS/FRLGTS customers) and the fixed monthly charges under Columbia's IRP and CEP riders. For example, Columbia's SGS/SGTS/FRSGTS customers are accustomed to being charged on a fixed monthly basis for gas delivery service consisting of a Monthly Delivery Charge of $16.75 per customer, an IRP Rider charge of $11.98 per customer and a CEP Rider charge of $5.92 per customer, for a total of $34.65 per customer. In this rate filing, Columbia proposes to roll into base rates the current charges under its IRP and CEP Riders. Since these two riders enable the recovery of a

[14] See Attachment RAF-3 comparing Column (9) to Column (5).

material portion of Columbia's fixed distribution costs, it is entirely appropriate to continue recovering these costs on a fixed charge basis through the Monthly Delivery Charges proposed by Columbia for each of its rate classes.

Q. How did you derive the proposed Monthly Delivery Charge applicable to Columbia's SGS/SGTS/FRSGTS customers?

A. The proposed Monthly Delivery Charge of $46.31 per customer for Columbia's SGS/SGTS/FRSGTS customers was derived to recover the proposed non-gas revenue requirement for this rate class[15] presented in Attachment RAF-2, page 7 of 10 (line 6). This computational method was used to reflect the SFV rate design approved by the Commission for these rate classes in Columbia's last rate case that was decided in December 2008.

Q. Do you believe the continued use of the SFV rate design for Columbia's SGS/SGTS/FRSGTS customers previously approved by the Commission is appropriate for pricing gas delivery service to these customers?

A. Yes, I do. From a ratemaking policy perspective, I believe it continues to be appropriate to recover 100% of the costs to deliver natural gas for these rate classes through a monthly fixed charge. Under an SFV rate structure, rates are designed so that customers pay a flat monthly fee for the gas delivery services provided by the gas utility. For Columbia, this type of rate design provides for the inclusion of all fixed costs of gas delivery service incurred by Columbia to serve its residential and small general service customers and the recovery of such costs through a single monthly charge. These customers continue to pay on a volumetric basis for the gas volumes used each month based on the commodity price of natural gas charged by either the customer's gas marketer or Columbia.

This type of ratemaking approach recognizes that because Columbia's costs of gas delivery service are fixed in nature, such costs should be recovered through a monthly fixed charge. It reflects the cost causation characteristics of gas delivery service and recognizes that the costs incurred by Columbia are relatively uniform, on average, across the range of customers in the SGS/SGTS/FRSGTS rate class. In addition, this rate design follows the "matching principle" of costs and rates which is a cornerstone of utility ratemaking. Under the "matching principle," the utility's customers should be

[15] Excluding revenues associated with purchased gas costs and revenues recovered through Columbia's Regulatory Assessment Rider ("RAR").

charged for utility service based on the costs of producing the type and level of service they receive. Finally, and most importantly, Columbia's SGS/SGTS/FRSGTS customers have been charged for gas delivery service under the SFV rate design method for over twelve years and are accustomed to paying a monthly fixed charge by Columbia for this type of utility service.

Q. In your opinion, is there strong support for the continuation of an SFV rate design for Columbia's SGS/SGTS/FRSGTS customers?

A. Yes. I believe an SFV rate design is the preferred pricing method for Columbia's residential and small general service customers for several important reasons:

- SFV rates offer the most economically efficient alternative to volumetric rates.
- SFV rates minimize the distortion of gas commodity prices, thus promoting more accurate commodity price signals to the customer, and hence provide greater economic efficiency.
- SFV rates track embedded costs more accurately, thus eliminating intra-class subsidies and undue discrimination within the residential and small general service rate classes.
- SFV rates provide the opportunity to recover revenue between rate cases without the use of a deferral ratemaking mechanism (e.g., a revenue decoupling mechanism).
- SFV rates provide customer bill stability.
- SFV rates represent a simple and easily understood rate.
- SFV rates avoid administrative and customer issues related to revenue decoupling mechanisms.
- SFV rates avoid the administrative burden on all parties associated with more complex ratemaking alternatives.
- SFV rates eliminate the financial incentive for the gas utility to increase sales which also positions the gas utility to pursue conservation and efficiency activities.
- SFV rates represent the best ratemaking alternative to address revenue instability.
- SFV rates eliminate the debate over the definition of normal weather and indeed eliminate the weather normalization process for base rates that recover a gas utility's fixed costs.

Several of these benefits were also recognized by the Commission in its Orders approving SFV rate design during the 2008-2010 time period for Vectren Energy Delivery of Ohio, Duke Energy Ohio, The East Ohio Gas Company dba Dominion East Ohio, Eastern Natural Gas Company, Pike Natural Gas Company, and Columbia.[16]

Q. Do you believe the Commission continues to recognize the benefits of an SFV rate design for a gas utility's residential and small general service customers?

A. Yes. The Commission reaffirmed its preference for an SFV rate design for gas distribution utilities in a 2017 proceeding for Suburban Natural Gas Company and in a 2018 proceeding for Vectren Energy Delivery of Ohio.[17] In the Vectren proceeding, the Commission found that "the evidence in the record of this case supports the retention of the SFV rate design as recommended by Staff and as agreed to in the Stipulation." The Commission noted in its Opinion and Order that the SFV rate design is the appropriate rate design for natural gas company distribution rates through a series of decisions it cited (many of which I cited above). The Commission concluded in that rate proceeding, "[w]e find that the weight of the evidence in this case decisively favors retention of the SFV rate design."

Q. Earlier you discussed Columbia's proposed transfer of customers from the GS/GTS/FRGTS rate class to the SGS/SGTS/FRSGTS rate class. Will the inclusion of these customers in the SGS/SGTS/FRSGTS rate class affect the continued use of an SFV rate design for this rate class?

A. No. In my judgment, the homogeneous nature of the load and cost characteristics of the SGS/SGTS/FRSGTS rate class is not materially affected by the

[16] See Duke Energy Ohio, Inc., Case Nos. 07-589-GA-AIR, et al., Opinion and Order (May 28, 2008); The East Ohio Gas Company dba Dominion East Ohio, Case Nos. 07-829-GA-AIR, et al., Opinion and Order (October 15, 2008); Columbia Gas of Ohio, Inc., Case Nos. 08-72-GA-AIR, et. al., Opinion and Order (December 3, 2008); Vectren Energy Delivery of Ohio, Case Nos. 07-1080-GA-AIR, et. al., Opinion and Order (January 7, 2009); and Eastern Natural Gas Company and Pike Natural Gas Company, Case Nos. 08-940-GA-ALT, et. al., Opinion and Order (June 16, 2010).

[17] See Suburban Natural Gas Company, Case No. 17-594-GA-ALT, Opinion and Order (November 1, 2017) at pp. 10-11, and Vectren Energy Delivery of Ohio, Case Nos. 18-298-GA-AIR, et. al, Opinion and Order (August 28, 2019) at pp. 74-76.

transfer into this rate class of smaller GS/GTS/FRGTS customers using between 300 Mcf and 600 Mcf per year.[18] As indicated earlier, there are about 17,000 customers in the GS/GTS/FRGTS rate class that were transferred into the SGS/SGTS/FRSGTS rate class that consists of about 1.43 million customers (before the customer transfer). The transferred customers represent about a 1.2% increase in the number of customers served in the SGS/SGTS/FRSGTS rate class.

In addition, the fixed, customer-related distribution costs to serve the average customer in the SGS/SGTS/FRSGTS rate class are not materially affected by the transfer of these customers.[19] Specifically with regard to service lines, I understand that the average GS/GTS/FRGTS customer being transferred to the SGS/SGTS/FRSGTS rate class can be served from a 1-inch service line at medium pressure on Columbia's gas system. Most SGS/SGTS/FRSGTS customers also are served from a 1-inch service line, so the transfer of the smaller GS/GTS/FRGTS customers will not materially impact the unit cost of a service line to serve the average SGS/SGTS/FRSGTS customer after the transfer. As a result, it is entirely appropriate to continue to charge all customers in this rate class a flat monthly fee for the gas delivery services provided by Columbia.

Q. How did you determine the proposed Monthly Delivery Charges applicable to Columbia's GS/GTS/FRGTS and LGS/LGTS/FRLGTS customers?

A. As a starting point, it was recognized that customers in the GS/GTS/FRGTS and LGS/LGTS/FRLGTS rate classes are currently charged on a fixed monthly basis for a material portion of the costs of gas delivery service through a monthly Customer Charge, the IRP Rider and the CEP Rider. The current charges for these rate components are presented in Attachment RAF-3, Columns (5) through (8). In the aggregate, approximately 42% of the current annualized revenues for the GS/GTS/FRGTS rate class is recovered from customers on a fixed charge basis, and for the

[18] Before the above-described customer transfer, the average customer in the SGS/SGTS/FRSGTS rate class consumes about 78.9 Mcf per year. After the customer transfer, the average SGS/SGTS/FRSGTS customer consumes about 82.7 Mcf per year.

[19] For example, the average unit cost of a meter and service for the SGS/SGTS/FRSGTS rate class before the customer transfer is $59/customer and $915, respectively. After the customer transfer, the average unit cost of a meter and service for the SGS/SGTS/FRSGTS rate class increases slightly to $62 and $929, respectively.

LGS/LGTS/FRLGTS rate class, that amount is approximately 71%.[20] In addition, Columbia's COSS results presented in Schedule E-3.1 provided additional guidance with the customer-related costs for these rate classes. Attachment RAF-3, Column (9) provides the sum of the current fixed charges under Columbia's IRP and CEP Riders and the customer-related costs from Columbia's COSS. This cost and rate information in conjunction with the other considerations I discussed earlier in my direct testimony provided the necessary guidance to determine the appropriate proposed Monthly Delivery Charges for the GS/GTS/FRGTS and LGS/LGTS/FRLGTS rate classes.

Based on these considerations, the proposed Monthly Delivery Charges for GS/GTS/FRGTS and LGS/LGTS/FRLGTS customers were established at the lower of: (1) the sum of the current monthly fixed charges under the IRP and CEP Riders and the customer-related costs for the rate class adjusted by the approximate percentage increase in revenues for the rate class; or (2) the percentage of margin revenues at current rates recovered through monthly fixed charges applied against the proposed annualized non-gas revenues in the rate class. Using this decision criterion, the proposed Monthly Delivery Charge of $194.00 per customer for the GS/GTS/FRGTS rate class is based on the second option while the proposed Monthly Delivery Charge of $5,560.00 per customer for the LGS/LGTS/FRLGTS rate class is based upon the first option. The proposed Monthly Delivery Charges for the GS/GTS/FRGTS and LGS/LGTS/FRLGTS rate classes represent an increase in the current level of monthly fixed charges paid by these two customer groups of 13.6% and 11.1%, respectively, which are both of a similar magnitude to the proposed percentage increases in revenue for these rate classes.[21] In my judgment, the proposed Monthly Delivery Charges for Columbia's GS/GTS/FRGTS and LGS/LGTS/FRLGTS customers are reasonable and fairly reflect the considerations I discussed earlier in my direct testimony regarding the derivation of these fixed charges.

Q. How did you determine the proposed Monthly Delivery Charge applicable to Columbia's FRCTS customers?

A. Columbia utilized the results of its customer cost analysis presented in Schedule E-3.1 which indicated the customer-related costs to serve FRCTS customers is $29.10 per bill. As a result, a Monthly Delivery Charge of

[20] See Schedule E-4, page 3 of 4, Columns L and M.

[21] See Attachment RAF-3, Column (11).

$30.00 per bill is proposed for this rate schedule. Currently, Columbia does not have a monthly fixed charge in this rate schedule. A Monthly Delivery Charge is being introduced for customers served under this rate schedule as a more appropriate and direct way to recover customer-related costs compared to the current method of recovering such costs solely through volumetric charges.

Q. Please explain how you derived Columbia's proposed volumetric charges in its GS/GTS/FRGTS, LGS/LGTS/FRLGTS, and FRCTS rate classes.

A. In general, Columbia's proposed volumetric charges in these rate classes were derived by setting the level of each charge to recover a portion of the balance of the non-gas revenues at proposed rates after accounting for the increase in non-gas revenues derived from the proposed Monthly Delivery Charges. For rate classes in which there were multiple rate blocks, the associated volumetric charges were derived in a manner to generally maintain the relative rate differentials on a percentage basis between rate blocks that exist in each rate class under current rates.

Q. How are Columbia's school customer accounts proposed to be treated for rate design purposes?

A. Maintaining its long-standing ratemaking policy, Columbia has proposed that all primary and secondary school customer accounts served under its various rate schedules will be charged rates that are five percent below the applicable non-school rates.

Q. Has Columbia provided bill comparisons that show the impact of its current and proposed rates on the monthly gas bills of varying-sized customers in each rate class?

A. Yes. Schedule E-5 presents typical bill comparisons at various monthly gas consumption levels for Columbia's customers in each of its rate classes. This Schedule shows the customer's current gas bill at each consumption level, the dollar increase, percent of increase and total bill, both excluding and including gas (fuel) costs.

Q. Is Columbia's proposal to eliminate the current Mainline Delivery Charge under the LGTS rate schedule supported by generally accepted utility ratemaking principles?

A. Yes. There are currently eighteen customers who receive gas delivery service under this rate provision in the LGTS rate schedule.[22] These customers are served by Columbia through a dual-purpose meter to facilities of an interstate pipeline and are currently charged a maximum base rate of $0.1635 per Mcf (the current tail block rate under the LGTS rate schedule) and a Customer Charge of $559.53 per month (the same Customer Charge paid by other LGTS customers). Under Columbia's proposal, these former LGTS-ML customers will be charged the same standard rates paid by any other LGTS customer based on each customer's specific load characteristics.

More broadly, the base rates for each of Columbia's rate schedules are designed on a systemwide basis in recognition of the integrated nature of Columbia's gas distribution system. This is a widely accepted rate design approach in the gas distribution utility industry, especially for a gas utility such as Columbia that has a multi pressure-based system, with multiple city-gate locations, where the transmission of gas between its load centers is functionally provided by its interstate gas pipeline suppliers. At the same time, my experience with the design of gas distribution utility rates has been that several gas utilities (including Columbia and other Ohio gas utilities) at times must charge rates that are less than their standard rates (i.e., less than their maximum rates) to be able to retain specific customers in the face of competition from alternate energy suppliers. In these circumstances, it is not unusual for the geographic location of the customer to be factored into the rate determination process, especially if the customer is located near the alternate energy supplier. However, this customer-specific approach to rate design should be the exception, and not the rule, to avoid the creation of multiple standard rates for the same utility service, with one justified solely on the specific location of the customer. This geographic approach to rate design may be viewed as unduly discriminatory for similarly sized customers within a specific rate class and, therefore, should be avoided for the setting of a gas utility's standard or maximum allowable base rates.

[22] There are currently 9 customers who pay the maximum Mainline Delivery Charge (i.e., standard rate customers) and 9 customers who pay a lower rate than the maximum rate because of competition from alternate energy suppliers.

Q. Is Columbia's proposal to eliminate the tariff provision in the LGS/LGTS/FRLGTS rate schedules that requires at least 50% of a customer's annual consumption must be consumed in the seven billing months of April through October to qualify for service under these rate schedules supported by generally accepted utility ratemaking principles?

A. Yes. Based on my review of this applicability provision, it appears to limit customers served under the LGS/LGTS/FRLGTS rate schedules to those customers who have less seasonal variability in their gas load characteristics. From a strictly conceptual perspective, this type of applicability provision can generally serve to incent customers to use gas on a more levelized basis by season and month, which ultimately benefits those customers because it is less costly (on unit cost basis) for a gas utility to serve customers that exhibit higher annual load factors. In my judgment, however, this type of applicability provision is not the most effective way to incent customers to utilize Columbia's gas system in a more efficient manner (i.e., consume gas at a higher annual load factor). Instead, the provision has effectively precluded certain GS/GTS/FRGTS customers from qualifying for service under the LGS/LGTS/FRLGTS rate schedules even though they satisfy the minimum annual volume requirement of 18,000 Mcf for the LGS/LGTS/FRLGTS rate schedules.

For those larger customers served under the LGS/LGTS/FRLGTS rate schedules who can consume gas on a more stable basis throughout the year, Columbia's COSS already recognizes the value of utilizing the gas distribution system in a more efficient manner through the allocation of demand-related costs using the design day demand for each rate class (i.e., the Coincident Peak Demand Allocation Method). The annual load factor for the LGS/LGTS/FRLGTS rate class in Columbia's COSS is 58% compared to an annual load factor of 24% for the GS/GTS/FRGTS rate class. As a result, the unit cost to serve Columbia's LGS/LGTS/FRLGTS customers is much lower than the unit cost of serving its GS/GTS/FRGTS customers. This outcome also has been recognized for these customers through the assignment of a lower than average increase in Columbia's class revenue apportionment proposal.

Q. Are there any differences between the rates proposed by Columbia in this filing and the rates submitted in its Notice of Intent to File an Application to Increase Rates ("NOI") on May 28, 2021?

A. Yes. In some instances, the rates proposed by Columbia in this filing are slightly lower than the rates submitted in its NOI.

Q. Please describe the factors that caused these changes to Columbia's proposed rates in this filing.

A. First, Columbia slightly reduced its total revenue requirement and proposed revenue increase request in this filing compared to the amounts that were used to design its rates for the NOI filing. Second, a few changes were made to the preliminary COSS used by Columbia to guide the design of rates for its NOI filing to refine the cost allocation methods and factors used in the COSS. The combination of these two factors caused the COSS results to change which resulted in the need for slight adjustments to Columbia's proposed class revenue apportionment and the associated rate levels.

Q. After the completion of this rate case and the implementation of Columbia's approved rates, is there an additional change in its future rates that Columbia and the Commission have agreed to implement?

A. Yes. As discussed in the direct testimony of Columbia witness Bryan Trapp, Columbia and the Commission agreed in 2018 to adjust its base rates to reflect the elimination of the reduction in base rates directly related to the pass-back of non-normalized (i.e., unprotected) Excess Accumulated Deferred Income Taxes ("EDIT") over the six-year period, January 1, 2018 through December 31, 2023. Based on the underlying computations in Attachment BAT-1 sponsored by Columbia witness Trapp, Columbia is seeking authorization from the Commission to increase base rate revenues on January 1, 2024 by $6.9 million.

Q. How does Columbia propose to recover this future increase in base rate revenues from its customers?

A. Columbia proposes to utilize an updated version of the same method it used in 2018 to reduce its base rates related to the pass-back of non-normalized EDIT. That method was based on Columbia's revenue by rate class priced out at the then current base rates using the final approved billing determinants from its 2008 rate case. The reduction in base rates by rate class was derived by allocating a portion of the total revenue decrease to each rate class using the resulting revenue distribution by rate class. The revenue distribution by rate class that Columbia proposes to use to allocate the EDIT-related revenue increase to its rate classes effective on January 1, 2024, will be based on Columbia's base revenues, base rates, and billing determinants (i.e., number of bills and gas consumption) by rate class that are approved by the Commission at the conclusion of this rate case.

Q. Does this complete your Prepared Direct Testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

The Public Utilities Commission of Ohio's e-filing system will electronically serve notice of the filing of this document on the parties referenced on the service list of the docket card who have electronically subscribed to the case. In addition, the undersigned hereby certifies that a copy of the foregoing document is also being served via electronic mail on the 14th day of July, 2021, upon the persons listed below.

/s/ Joseph M. Clark
Joseph M. Clark

Attorney for
COLUMBIA GAS OF OHIO, INC.

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EDUCATIONAL BACKGROUND, WORK EXPERIENCE AND REGULATORY EXPERIENCE
RUSSELL A. FEINGOLD

EDUCATIONAL BACKGROUND

- Bachelor of Science degree in Electrical Engineering from Washington University in St. Louis
- Master of Science degree in Financial Management from Polytechnic Institute of New York University

WORK EXPERIENCE

2007 – Present	**Black & Veatch Management Consulting, LLC** Vice President and Rates & Regulatory Practice Lead
1996 – 2007	**Navigant Consulting, Inc.** Managing Director, Energy Practice - Litigation, Regulatory & Markets Group; Energy Delivery Practice Lead
1990 – 1996	**R.J. Rudden Associates, Inc**. Vice President and Director
1985 – 1990	**Price Waterhouse** Director, Gas Regulatory Services Public Utilities Industry Services Group
1978 – 1985	**Stone & Webster Management Consultants, Inc.** Executive Consultant Regulatory Services Division
1973 – 1978	**Port Authority of New York and New Jersey** Staff Engineer and Utility Rate Specialist Design Engineering Division

PRESENTATION OF EXPERT TESTIMONY

- Federal Energy Regulatory Commission
- National Energy Board of Canada
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Iowa Utilities Board
- Kentucky Public Service Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- Nebraska Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities
- New Mexico Public Regulation Commission
- New York Public Service Commission

- North Carolina Utilities Commission
- North Dakota Public Service Commission
- Ohio Public Utilities Commission
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Régie de l'Énergie Quebec (Canada)
- South Dakota Public Service Commission
- Tennessee Regulatory Authority
- Utah Public Service Commission
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of Wyoming

EDUCATIONAL AND TRAINING ACTIVITIES

- Past Chairman, Rate Training Subcommittee, Rate and Strategic Issues Committee of the American Gas Association.
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison and University of Chicago School of Business, 1985 - 2020.

- Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland - College Park, 1987 –1992, and University of Chicago School of Business, 2012-2019.
- Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.
- Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987 edition.
- Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress).
- Contributing Author of "Regulation of the Gas Industry," LexisNexis Matthew Bender, 2016, 2019 and 2020.

AFFILIATIONS AND HONORS

- Financial Associate Member, American Gas Association
- Member, State Affairs Committee of the American Gas Association
- Member, Energy Bar Association
- Life Member, Institute of Electrical and Electronic Engineers
- Listed in Who's Who of Emerging Leaders in America, 1989-1992

(Current as of June 2021)

Columbia Gas of Ohio, Inc.
Case No. 21-637-GA-AIR
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2021

HIGHLY CONFIDENTIAL

Line No.	Description	Adjusted Bills (1) (Schedule E-4)	Adjusted Volumes (2) MCF (Schedule E-4)	Revenue @ Current Rates (3) $ (Schedule E-4)	Proposed Revenue Increase (4) $	Total Proposed Revenue (5 = 3 + 4) $ (Schedule E-4)	Proposed Increase by Rate Schedule (6) %	Proposed Increase by Rate Schedules (7) %	Proposed Increase by Rate Class (1) (8) %
1	**Total Revenues**								
2	Small General Service - DSS	1,553,868	9,343,962 3	97,222,739 98	18,059,233 91	115,281,973 89	18 58%	31 38%	31 38%
3	Small General Service - SCO	7,642,322	49,272,853 4	264,806,457 30	89,109,474 52	353,915,931 82	33 65%	31 38%	
4	Small General Service Schools - SCO	24	825 4	811 44	244 32	1,055 76	30 11%	30 11%	
5	Small General Service - Choice Transportation	8,191,628	61,126,934 5	283,839,910 20	95,514,382 48	379,354,292 68	33 65%	31 38%	
6	Small General Service Schools - Choice Transportation	84	1,076 6	2,840 04	855 12	3,695 16	30 11%	30 11%	
7	Small General Service - Transportation Service	1,023	24,340 4	35,446 95	11,928 18	47,375 13	33 65%	31 38%	
8	Small General Service Schools - Transportation Service	3,474	80,567 0	117,455 94	35,365 32	152,821 26	30 11%	30 11%	
9	General Service - DSS	5,942	2,006,930 1	12,361,296 48	370,142 61	12,731,439 09	2 99%	11 71%	11 39%
10	General Service Schools - DSS	0	0 0	0 00	0 00	0 00	0 00%	10 91%	
11	General Service - SCO	50,999	5,839,963 4	15,499,720 45	2,043,664 16	17,543,384 61	13 19%	11 71%	
12	General Service Schools - SCO	139	26,303 0	51,480 50	5,513 36	56,993 86	10 71%	10 91%	
13	General Service - Choice Transportation	154,047	19,928,388 6	49,302,292 81	6,481,485 02	55,783,777 83	13 15%	11 71%	
14	General Service Schools - Choice Transportation	206	42,067 3	78,800 72	8,450 77	87,251 49	10 72%	10 91%	
15	General Service - Choice Transportation Flex	[redacted]		140,371 21	0 00	140,371 21	0 00%	0 00%	
16	General Service - Transportation Service	21,660	22,729,017 8	26,426,201 42	3,236,206 40	29,662,407 82	12 25%	11 71%	
17	General Service Schools - Transportation Service	13,619	3,853,908 2	6,206,525 90	677,475 75	6,884,001 65	10 92%	10 91%	
18	General Service - Transportation Service Flex	[redacted]		2,558,857 84	0 00	2,558,857 84	0 00%	0 00%	
19	Large General Service - DSS	106	496,509 4	2,980,272 22	158,749 55	3,139,021 77	5 33%	24 51%	14 98%
20	Large General Service - SCO	23	88,682 7	143,320 53	32,846 87	176,167 40	22 92%	24 51%	
21	Large General Service - Choice Transportation	36	202,099 1	237,952 31	61,165 92	299,118 23	25 71%	24 51%	
22	Large General Service - Choice Transportation Flex	[redacted]		0 00	0 00	0 00	0 00%	0 00%	
23	Large General Service - Transportation Service	2,702	21,417,337 4	19,195,328 74	5,535,097 57	24,730,426 31	28 84%	24 51%	
24	Large General Service - Transportation Service Flex	[redacted]		15,117,558 74	0 00	15,117,558 74	0 00%	0 00%	
25	Large General Service - Transportation Service Main Line	0	0 0	0 00	0 00	0 00	0 00%	0 00%	
26	Large General Service - Transportation Service Main Line Flex	[redacted]		0 00	0 00	0 00	0 00%	0 00%	
27	Large General Service - Wholesale DSS	12	244,064 7	1,249,055 14	44,730 49	1,293,785 63	3 58%	24 51%	
28	Large General Service - Transportation Service - Schools	0	0 0	0 00	0 00	0 00	0 00%	24 51%	
29	Cooperative Service	263	330,507 7	290,548 54	37,068 76	327,617 30	12 76%	12 76%	12 71%
30	Cooperative Service CoOpt-Choice Industrial Flex	[redacted]		998 45	0 00	998 45	0 00%	0 00%	
31	Other Gas Department Revenue			20,096,079 06	0 00	20,096,079 06	0 00%	0 00%	
32	Total Revenues	17,643,918	258,444,091 7	817,962,322 91	221,424,081 08	1,039,386,403 99	27 07%	27 07%	27 75%
				0		(0)		(1) Excl Other Rev	
33	**Base Rate Revenue Only**								
34	Small General Service - DSS	1,553,868	9,343,962 3	26,027,289 00	45,932,338 08	71,959,627 08	176 48%	176 48%	
35	Small General Service - SCO	7,642,322	49,272,853 4	128,008,893 50	225,907,038 32	353,915,931 82	176 48%	176 48%	
36	Small General Service Schools - SCO	24	825 4	381 84	673 92	1,055 76	176 49%	176 49%	
37	Small General Service - Choice Transportation	8,191,628	61,126,934 5	137,209,769 00	242,144,523 68	379,354,292 68	176 48%	176 48%	
38	Small General Service Schools - Choice Transportation	84	1,076 6	1,336 44	2,358 72	3,695 16	176 49%	176 48%	
39	Small General Service - Transportation Service	1,023	24,340 4	17,135 25	30,239 88	47,375 13	176 48%	176 48%	
40	Small General Service Schools - Transportation Service	3,474	80,567 0	55,271 34	97,549 92	152,821 26	176 49%	176 49%	
41	General Service - DSS	5,942	2,006,930 1	2,154,442 38	1,272,065 99	3,426,508 37	59 04%	78 99%	
42	General Service Schools - DSS	0	0 0	0 00	0 00	0 00	0 00%	65 49%	
43	General Service - SCO	50,999	5,839,963 4	7,867,210 11	9,676,174 50	17,543,384 61	122 99%	78 99%	
44	General Service Schools - SCO	139	26,303 0	30,677 76	26,316 10	56,993 86	85 78%	65 49%	
45	General Service - Choice Transportation	154,047	19,928,388 6	26,247,618 79	29,536,159 04	55,783,777 83	112 53%	78 99%	
46	General Service Schools - Choice Transportation	206	42,067 3	47,970 76	39,280 73	87,251 49	81 88%	65 49%	
47	General Service - Choice Transportation Flex	[redacted]		135,208 09	0 00	135,208 09	0 00%	0 00%	
48	General Service - Transportation Service	21,660	22,729,017 8	23,184,565 82	6,477,842 00	29,662,407 82	27 94%	78 99%	
49	General Service Schools - Transportation Service	13,619	3,853,908 2	4,168,306 36	2,715,695 29	6,884,001 65	65 15%	65 49%	
50	General Service - Transportation Service Flex	[redacted]		2,500,342 48	0 00	2,500,342 48	0 00%	0 00%	

Columbia Gas of Ohio, Inc.
Case No. 21-637-GA-AIR
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For the 12 Months Ended December 31, 2021

HIGHLY CONFIDENTIAL

Line No.	Description	Adjusted Bills (1) (Schedule E-4)	Adjusted Volumes (2) MCF (Schedule E-4)	Revenue @ Current Rates (3) $ (Schedule E-4)	Proposed Revenue Increase (4) $	Total Proposed Revenue (5 = 3 + 4) $ (Schedule E-4)	Proposed Increase by Rate Schedule (6) %	Proposed Increase by Rate Schedules (7) %
1	Large General Service - DSS	106	496,509 4	203,854 14	633,151 44	837,005 58	310 59%	246 27%
2	Large General Service - SCO	23	88,682 7	41,062 99	135,104 41	176,167 40	329 02%	246 27%
3	Large General Service - Choice Transportation	36	202,099 1	77,897 03	221,221 20	299,118 23	283 99%	246 27%
4	Large General Service - Choice Transportation Flex	[redacted]	[redacted]	0 00	0 00	0 00	0 00%	0 00%
5	Large General Service - Transportation Service	2,702	21,417,337 4	7,182,290 78	17,548,135 53	24,730,426 31	244 33%	246 27%
6	Large General Service - Transportation Service Flex	[redacted]	[redacted]	12,982,444 22	0 00	12,982,444 22	0 00%	0 00%
7	Large General Service - Transportation Service Main Line	0	0 0	0 00	0 00	0 00	0 00%	0 00%
8	Large General Service - Transportation Service Main Line Flex	[redacted]	[redacted]	0 0	0 00	0 00	0 00%	0 00%
9	Large General Service Wholesale - DSS	12	244,064 7	62,584 18	99,619 86	162,204 04	159 18%	246 27%
10	Large General Service - Transportation Service - Schools	0	0 0	0 00	0 00	0 00	0 00%	246 27%
11	Cooperative Service	263	330,507 7	290,548 54	37,068 76	327,617 30	12 76%	12 76%
12	Cooperative Service CoOpt-Choice Industrial Flex	[redacted]	[redacted]	998 45	0 00	998 45	0 00%	0 00%
13	Total Base Revenue	17,643,918	258,444,091 7	378,498,099 25	582,532,557 37	961,030,656 62	153 91%	153 91%
14	**Infrastructure Replacement Plan Rider**							
15	Small General Service - DSS			18,615,338 64	(18,615,338 64)	0 00	-100 00%	-100 00%
16	Small General Service - SCO			91,555,017 56	(91,555,017 56)	0 00	-100 00%	-100 00%
17	Small General Service Schools - SCO			287 52	(287 52)	0 00	-100 00%	-100 00%
18	Small General Service - Choice Transportation			98,135,703 44	(98,135,703 44)	0 00	-100 00%	-100 00%
19	Small General Service Schools - Choice Transportation			1,006 32	(1,006 32)	0 00	-100 00%	-100 00%
20	Small General Service - Transportation Service			12,255 54	(12,255 54)	0 00	-100 00%	-100 00%
21	Small General Service Schools - Transportation Service			41,618 52	(41,618 52)	0 00	-100 00%	-100 00%
22	General Service - DSS			642,805 56	(642,805 56)	0 00	-100 00%	-100 00%
23	General Service Schools - DSS			0 00	0 00	0 00	0 00%	-100 00%
24	General Service - SCO			5,517,071 82	(5,517,071 82)	0 00	-100 00%	-100 00%
25	General Service Schools - SCO			15,037 02	(15,037 02)	0 00	-100 00%	-100 00%
26	General Service - Choice Transportation			16,664,804 46	(16,664,804 46)	0 00	-100 00%	-100 00%
27	General Service Schools - Choice Transportation			22,285 08	(22,285 08)	0 00	-100 00%	-100 00%
28	General Service - Choice Transportation Flex			3,894 48	0 00	3,894 48	0 00%	0 00%
29	General Service - Transportation Service			2,343,178 80	(2,343,178 80)	0 00	-100 00%	-100 00%
30	General Service Schools - Transportation Service			1,473,303 42	(1,473,303 42)	0 00	-100 00%	-100 00%
31	General Service - Transportation Service Flex			44,137 44	0 00	44,137 44	0 00%	0 00%
32	Large General Service - DSS			364,653 78	(364,653 78)	0 00	-100 00%	-100 00%
33	Large General Service - SCO			79,122 99	(79,122 99)	0 00	-100 00%	-100 00%
34	Large General Service - Choice Transportation			123,844 68	(123,844 68)	0 00	-100 00%	-100 00%
35	Large General Service - Choice Transportation Flex			0 00	0 00	0 00	0 00%	0 00%
36	Large General Service - Transportation Service			9,295,231 26	(9,295,231 26)	0 00	-100 00%	-100 00%
37	Large General Service - Transportation Service Flex			1,251,428 40	0 00	1,251,428 40	0 00%	0 00%
38	Large General Service - Transportation Service Main Line			0 00	0 00	0 00	0 00%	0 00%
39	Large General Service - Transportation Service Main Line Flex			0 00	0 00	0 00	0 00%	0 00%
40	Large General Service Wholesale - DSS			41,281 56	(41,281 56)	0 00	-100 00%	-100 00%
41	Large General Service - Transportation Service - Schools			0 00	0 00	0 00	0 00%	-100 00%
42	Cooperative Service			0 00	0 00	0 00	0 00%	0 00%
43	Cooperative Service CoOpt-Choice Industrial Flex			0 00	0 00	0 00	0 00%	0 00%
44	Total Infrastructure Replacement Plan			246,243,308 29	(244,943,847 97)	1,299,460 32	-99 47%	-99 47%

Columbia Gas of Ohio, Inc.
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For the 12 Months Ended December 31, 2021

Line No.	Description	Adjusted Bills (1) (Schedule E-4)	Adjusted Volumes (2) MCF (Schedule E-4)	Revenue @ Current Rates (3) $ (Schedule E-4)	Proposed Revenue Increase (4) $	Total Proposed Revenue (5 = 3 + 4) $ (Schedule E-4)	Proposed Increase by Rate Schedule (6) %	Proposed Increase by Rate Schedules (7) %
1	**Capital Expenditure Program Rider**							
2	Small General Service - DSS			9,198,898 56	(9,198,898 56)	0 00	-100 00%	-100 00%
3	Small General Service - SCO			45,242,546 24	(45,242,546 24)	0 00	-100 00%	-100 00%
4	Small General Service Schools - SCO			142 08	(142 08)	0 00	-100 00%	-100 00%
5	Small General Service - Choice Transportation			48,494,437 76	(48,494,437 76)	0 00	-100 00%	-100 00%
6	Small General Service Schools - Choice Transportation			497 28	(497 28)	0 00	-100 00%	-100 00%
7	Small General Service - Transportation Service			6,056 16	(6,056 16)	0 00	-100 00%	-100 00%
8	Small General Service Schools - Transportation Service			20,566 08	(20,566 08)	0 00	-100 00%	-100 00%
9	General Service - DSS			246,474 16	(246,474 16)	0 00	-100 00%	-100 00%
10	General Service Schools - DSS			0 00	0 00	0 00	0 00%	-100 00%
11	General Service - SCO			2,115,438 52	(2,115,438 52)	0 00	-100 00%	-100 00%
12	General Service Schools - SCO			5,765 72	(5,765 72)	0 00	-100 00%	-100 00%
13	General Service - Choice Transportation			6,389,869 56	(6,389,869 56)	0 00	-100 00%	-100 00%
14	General Service Schools - Choice Transportation			8,544 88	(8,544 88)	0 00	-100 00%	-100 00%
15	General Service - Choice Transportation Flex			1,268 64	0 00	1,268 64	0 00%	0 00%
16	General Service - Transportation Service			898,456 80	(898,456 80)	0 00	-100 00%	-100 00%
17	General Service Schools - Transportation Service			564,916 12	(564,916 12)	0 00	-100 00%	-100 00%
18	General Service - Transportation Service Flex			14,377 92	0 00	14,377 92	0 00%	0 00%
19	Large General Service - DSS			106,620 10	(106,620 10)	0 00	-100 00%	-100 00%
20	Large General Service - SCO			23,134 55	(23,134 55)	0 00	-100 00%	-100 00%
21	Large General Service - Choice Transportation			36,210 60	(36,210 60)	0 00	-100 00%	-100 00%
22	Large General Service - Choice Transportation Flex			0 00	0 00	0 00	0 00%	0 00%
23	Large General Service - Transportation Service			2,717,806 70	(2,717,806 70)	0 00	-100 00%	-100 00%
24	Large General Service - Transportation Service Flex			883,686 12	0 00	883,686 12	0 00%	0 00%
25	Large General Service - Transportation Service Main Line			0 00	0 00	0 00	0 00%	0 00%
26	Large General Service - Transportation Service Main Line Flex			0 00	0 00	0 00	0 00%	0 00%
27	Large General Service Wholesale - DSS			12,070 20	(12,070 20)	0 00	-100 00%	-100 00%
28	Large General Service - Transportation Service - Schools			0 00	0 00	0 00	0 00%	-100 00%
29	Cooperative Service			0 00	0 00	0 00	0 00%	0 00%
30	Cooperative Service CoOpt-Choice Industrial Flex			0 00	0 00	0 00	0 00%	0 00%
31	Total Capital Expenditure Program Rider			116,987,784 75	(116,088,452 07)	899,332 68	-99 23%	-99 23%

Columbia Gas of Ohio, Inc.
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For the 12 Months Ended December 31, 2021

Line No.	Description	Adjusted Bills (1) (Schedule E-4)	Adjusted Volumes (2) MCF (Schedule E-4)	Revenue @ Current Rates (3) $ (Schedule E-4)	Proposed Revenue Increase (4) $	Total Proposed Revenue (5 = 3 + 4) $ (Schedule E-4)	Proposed Increase by Rate Schedule (6) %	Proposed Increase by Rate Schedules (7) %
1	**Regulatory Assessment Rider**							
2	Small General Service - DSS			165,388 14	(58,866 97)	106,521 17	-35 59%	-35 59%
3	Small General Service - SCO			0 00	0 00	0 00	0 00%	-35 59%
4	Small General Service Schools - SCO			0 00	0 00	0 00	0 00%	0 00%
5	Small General Service - Choice Transportation			0 00	0 00	0 00	0 00%	-35 59%
6	Small General Service Schools - Choice Transportation			0 00	0 00	0 00	0 00%	-35 59%
7	Small General Service - Transportation Service			0 00	0 00	0 00	0 00%	-35 59%
8	Small General Service Schools - Transportation Service			0 00	0 00	0 00	0 00%	0 00%
9	General Service - DSS			35,522 67	(12,643 66)	22,879 01	-35 59%	-35 59%
10	General Service Schools - DSS			0 00	0 00	0 00	0 00%	-35 59%
11	General Service - SCO			0 00	0 00	0 00	0 00%	-35 59%
12	General Service Schools - SCO			0 00	0 00	0 00	0 00%	-35 59%
13	General Service - Choice Transportation			0 00	0 00	0 00	0 00%	-35 59%
14	General Service Schools - Choice Transportation			0 00	0 00	0 00	0 00%	-35 59%
15	General Service - Choice Transportation Flex			0 00	0 00	0 00	0 00%	-35 59%
16	General Service - Transportation Service			0 00	0 00	0 00	0 00%	-35 59%
17	General Service Schools - Transportation Service			0 00	0 00	0 00	0 00%	-35 59%
18	General Service - Transportation Service Flex			0 00	0 00	0 00	0 00%	0 00%
19	Large General Service - DSS			8,788 22	(3,128 01)	5,660 21	-35 59%	-35 59%
20	Large General Service - SCO			0 00	0 00	0 00	0 00%	-35 59%
21	Large General Service - Choice Transportation			0 00	0 00	0 00	0 00%	-35 59%
22	Large General Service - Choice Transportation Flex			0 00	0 00	0 00	0 00%	-35 59%
23	Large General Service - Transportation Service			0 00	0 00	0 00	0 00%	-35 59%
24	Large General Service - Transportation Service Flex			0 00	0 00	0 00	0 00%	-35 59%
25	Large General Service - Transportation Service Main Line			0 00	0 00	0 00	0 00%	-35 59%
26	Large General Service - Transportation Service Main Line Flex			0 00	0 00	0 00	0 00%	0 00%
27	Large General Service Wholesale - DSS			4,319 95	(1,537 61)	2,782 34	-35 59%	-35 59%
28	Coorporative Service			0 00	0 00	0 00	0 00%	0 00%
29	Cooperative Service CoOpt-Choice Industrial Flex			0 00	0 00	0 00	0 00%	0 00%
30	Total Regulatory Assessment Rider			214,018 98	(76,176 25)	137,842 73	-35 59%	-35 59%

Columbia Gas of Ohio, Inc.
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Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2021

Line No.	Description	Adjusted Bills (1) (Schedule E-4)	Adjusted Volumes (2) MCF (Schedule E-4)	Revenue @ Current Rates (3) $ (Schedule E-4)	Proposed Revenue Increase (4) $	Total Proposed Revenue (5 = 3 + 4) $ (Schedule E-4)	Proposed Increase by Rate Schedule (6) %	Proposed Increase by Rate Schedules (7) %
1	**Gas Cost Recovery**							
2	Small General Service - DSS			43,215,825 64	0 00	43,215,825 64	0 00%	0 00%
3	Small General Service - SCO			0 00	0 00	0 00	0 00%	0 00%
4	Small General Service Schools - SCO			0 00	0 00	0 00	0 00%	0 00%
5	Small General Service - Choice Transportation			0 00	0 00	0 00	0 00%	0 00%
6	Small General Service Schools - Choice Transportation			0 00	0 00	0 00	0 00%	0 00%
7	Small General Service - Transportation Service			0 00	0 00	0 00	0 00%	0 00%
8	Small General Service Schools - Transportation Service			0 00	0 00	0 00	0 00%	0 00%
9	General Service - DSS			9,282,051 71	0 00	9,282,051 71	0 00%	0 00%
10	General Service Schools - DSS			0 00	0 00	0 00	0 00%	0 00%
11	General Service - SCO			0 00	0 00	0 00	0 00%	0 00%
12	General Service Schools - SCO			0 00	0 00	0 00	0 00%	0 00%
13	General Service - Choice Transportation			0 00	0 00	0 00	0 00%	0 00%
14	General Service Schools - Choice Transportation			0 00	0 00	0 00	0 00%	0 00%
15	General Service - Choice Transportation Flex			0 00	0 00	0 00	0 00%	0 00%
16	General Service - Transportation Service			0 00	0 00	0 00	0 00%	0 00%
17	General Service Schools - Transportation Service			0 00	0 00	0 00	0 00%	0 00%
18	General Service - Transportation Service Flex			0 00	0 00	0 00	0 00%	0 00%
19	Large General Service - DSS			2,296,355 98	0 00	2,296,355 98	0 00%	0 00%
20	Large General Service - SCO			0 00	0 00	0 00	0 00%	0 00%
21	Large General Service - Choice Transportation			0 00	0 00	0 00	0 00%	0 00%
22	Large General Service - Choice Transportation Flex			0 00	0 00	0 00	0 00%	0 00%
23	Large General Service - Transportation Service			0 00	0 00	0 00	0 00%	0 00%
24	Large General Service - Transportation Service Flex			0 00	0 00	0 00	0 00%	0 00%
25	Large General Service - Transportation Service Main Line			0 00	0 00	0 00	0 00%	0 00%
26	Large General Service - Transportation Service Main Line Flex			0 00	0 00	0 00	0 00%	0 00%
27	Large General Service - Transportation Service - Schools			0 00	0 00	0 00	0 00%	0 00%
28	Large General Service Wholesale - DSS			1,128,799 25	0 00	1,128,799 25	0 00%	0 00%
29	Coorporative Service			0 00	0 00	0 00	0 00%	0 00%
30	Cooperative Service CoOpt-Choice Industrial Flex			0 00	0 00	0 00	0 00%	0 00%
31	Total Gas Cost Recovery Rider			55,923,032 58	0 00	55,923,032 58	0 00%	0 00%
				($797,866,243 85)	($0 00)	($1,019,290,324 93)		

Columbia Gas of Ohio, Inc.
Case No. 21-637-GA-AIR
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For the 12 Months Ended December 31, 2021

Line No.	Description	Total (1)	SGS/SGTS FRSGTS (2)	GS/GTS FRGTS (3)	LGS/LGTS FRLGTS (3)	LGTS-M/L (4)	FRCTS (5)
1	**Determination of Revenue Distribution**						
2	Rate Base (Schedule B-1 and E-3 2-1)	$3,560,230,629 60	$3,114,920,184 29	$305,536,572 94	$138,439,788 07	$0 00	$1,334,084 30
3							
4	Unitized Return @ Current Rates (Schedule E-3 2-1)	1 000	0 32875	6 54290	3 85332	0 00000	2 73107
5	**Proposed Unitized Return**	1 000	0 77780	2 87000	1 86860	0 00000	1 29820
6	**Change in Unitized Return**	**0.000**	**0.449**	**(3.673)**	**(1.985)**	**0.000**	**(1.433)**
7	Rate of Return Requested	7 850%	6 106%	22 530%	14 669%	0 000%	10 191%
8	Net Operating Income @ Requested Return (Schedule A and E-3 2-1)	$279,478,104 00	$190,197,026 00	$68,837,390 00	$20,307,733 00	$0 00	$135,957 00
9	Net Operating Income @ Current Rates (Schedule E-3 2-1)	$104,553,081 63	$30,072,943 83	$58,707,276 14	$15,665,864 05	$0 00	$106,997 61
10	Income Deficiency (Line 8 - Line 9)	$174,925,022 37	$160,124,082 17	$10,130,113 86	$4,641,868 95	$0 00	$28,959 39
11	Gross Converstion Factor	1 265822785	1 265822785	1 265822785	1 265822785	1 265822785	1 265822785
12	**Revenue Required Increase (Schedule C-1)**	**221,424,081.47**	**202,688,711.60**	**12,822,928.93**	**5,875,783.48**	**0.00**	**36,657.46**
13	**Percent Distribution to Rate Classes**	**100.00%**	**91.54%**	**5.79%**	**2.65%**	**0.00%**	**0.02%**
14	**Proposed Rate Increase by Rate Class**	**27.75%**	**31.38%**	**11.39%**	**14.98%**	**0.00%**	**12.71%**
15	Regulatory Assessment Rider @ Current Rates	214,018 98	165,388 14	35,522 67	13,108 17	0 00	0 00
16	Regulatory Assessment Rider Change	(75,596 71)	(58,866 97)	(12,643 67)	(4,665 63)	0 00	0 00
17	Regulatory Assessment Rider @ Proposed Rates	138,422 27	106,521 17	22,879 00	8,442 54	0 00	0 00
18	Regulatory Assessment Rider Volumes (Mcf)	12,091,466 5	9,343,962 3	2,006,930 1	740,574 1	0 0	0 0
19	**Proposed Regulatory Assessment Rider Rate $/(Mcf)**	**0.0114**					
20	Less: Proposed Change to Regulatory Assessment Rider	(76,176 27)	(58,866 97)	(12,643 67)	(4,665 63)	0 00	0 00
21	Less: Proposed Change to Other Gas Department Revenue	0 00	0 00	0 00	0 00	0 00	0 00
22	**Proposed Base Revenue Increase**	**221,500,257.74**	**202,747,578.57**	**12,835,572.60**	**5,880,449.11**	**0.00**	**36,657.46**
23	**Percent Distribution to Rate Classes**	**100.00%**	**91.54%**	**5.79%**	**2.65%**	**0.00%**	**0.02%**
24	**Current Rate Revenue (Incl. RAR Change)**	**$797,866,243.85**	**646,025,661.85**	**112,625,547.33**	**38,923,487.68**	**0.00**	**291,546.99**
25	**Current Percent Distribution of Rate Classes**	**100.00%**	**80.97%**	**14.12%**	**4.88%**	**0.00%**	**0.04%**
26	**Proposed Rate Revenue (Incl. RAR Change)**	**$1,019,290,325.32**	**848,714,373.45**	**125,448,476.26**	**44,799,271.16**	**0.00**	**328,204.45**
27	**Proposed Percent Distribution of Rate Classes**	**100.00%**	**83.27%**	**12.31%**	**4.40%**	**0.00%**	**0.03%**

Columbia Gas of Ohio, Inc.
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For the 12 Months Ended December 31, 2021

Line No.		Bills	MCF	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1	**Small General Service Rate Design (SGS, FRSGTS, SGTS)**								
2	Total Revenue @ Current Rates				646,025,661 85				
3	Less: Gas Cost Recovery				43,215,825 64				
4	Less: Regulatory Assessment Rider				165,388 14				
5	Plus: Proposed Increase to Base Rates				202,747,578 57				
6	Proposed Base Revenue				805,392,026 64				
7	Less: Fixed Monthly Delivery Charge Revenue - Schools	3,582		**43.99**	157,572 18	56,989 62		15 91	100,582 56
8	Less: Fixed Monthly Delivery Charge Revenue - All other	17,388,841		**46.31**	805,277,226 71	291,263,086 75		16 75	514,014,139 96
9	Net Volumetric Gas Revenue				(42,772 25) (rounding)				
10	All Gas Consumed Schools (Schedule E-4 1)		82,469 0	**0.0000**	0 00	0 00	0 00%	0 0000	0 00
11	All Gas Consumed (Schedule E-4 1)		119,768,090 6	**0.0000**	0 00	0 00	0 00%	0 0000	0 00
12	Net Volumetric Gas Revenue				0 00	0 00	0 00%		0 00
13	Total Base Revenue Charge Increase								**514,114,722.52**
14	Total Infrastructure Replacement Plan Decrease								**(208,361,227.54)**
15	Total Capital Expenditure Program Rider Decrease								**(102,963,144.16)**
16	Total Change in SGS Revenue								**202,790,350.82**

Columbia Gas of Ohio, Inc.
Case No. 21-637-GA-AIR
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2021

HIGHLY CONFIDENTIAL

Line No.		Bills	MCF	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1	**General Service Rate Design (GS,FRGTS,GTS)**								
2	Total Revenue @ Current Rates				112,625,547 33				
3	Less: Gas Cost Recovery				9,282,051 71				
4	Less: Regulatory Assessment Rider				35,522 67				
5	Plus: Proposed Increase to Base Rates				12,835,572 60				
6	Proposed Base Revenue				116,143,545 55				$ 47,467,242
7	Less: General Service - Choice Transportation Flex Base Revenue	[redacted]			135,208 09				$ 193 02
8	Less: General Service - Transportation Service Flex Base Revenue				2,500,342 48				Use $194 00
9	Less: General Service - Choice Transportation Flex IRP Revenue				3,894 48				
10	Less: General Service - Transportation Service Flex IRP Revenue				44,137 44				
11	Less: General Service - Choice Transportation Flex CEP Revenue				1,268 64				
12	Less: General Service - Transportation Service Flex CEP Revenue				14,377 92				
13	Net Proposed Base Revenue				113,444,316 50				
14	Less: Customer Charge Revenue - Schools	13,964		**184.30**	2,573,565 20	280,676 40		20 10	2,292,888 80
15	Less: Customer Charge Revenue - All other non-flex	232,648		**194.00**	45,133,712 00	4,922,831 68		21 16	40,210,880 32
16	Net Volumetric Gas Revenue				65,737,039 30				
17	First 25 Mcf Schools (Schedule E-4 1)		298,913 0	**1.7450**	521,606 17	458,921 13	11 57%	1 5353	62,685 04
18	Next 75 Mcf Schools (Schedule E-4 1)		686,806 2	**1.3127**	901,577 37	797,794 08	20 11%	1 1616	103,783 29
19	Over 100 Mcf Schools (Schedule E-4 1)		2,936,559 3	**1.0323**	3,031,498 26	2,709,563 27	68 32%	0 9227	321,934 99
20	Net Volumetric Gas Revenue - Schools				4,454,681 80	3,966,278 48	100 00%		488,403 32
21	First 25 Mcf (Schedule E-4 1)		4,684,260 5	**1.8369**	8,604,297 91	7,570,233 40	13 88%	1 6161	1,034,064 51
22	Next 75 Mcf (Schedule E-4 1)		9,782,702 8	**1.3818**	13,517,761 90	11,961,310 71	21 93%	1 2227	1,556,451 19
23	Over 100 Mcf (Schedule E-4 1)		36,037,336 6	**1.0867**	39,160,306 81	34,999,461 31	64 18%	0 9712	4,160,845 50
24	Net Volumetric Gas Revenue - All Other				61,282,366 62	54,531,005 42	100 00%		6,751,361 20
25	Total Base Revenue Charge Increase					6,751,361 20			**49,743,533.64**
26	Total Infrastructure Replacement Plan Decrease					12 4%			**(26,678,486.16)**
27	Total Capital Expenditure Program Rider Decrease								**(10,229,465.76)**
28	Total Change in GS Revenue								**12,835,581.72**

Columbia Gas of Ohio, Inc.
Case No. 21-637-GA-AIR
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For the 12 Months Ended December 31, 2021

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Line No.		Bills	MCF	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1	**Large General Service Rate Design (LGS,FRLGTS,LGTS)**								
2	Total Revenue @ Current Rates				38,923,487 68				
3	Less: Gas Cost Recovery				3,425,155 23				
4	Less: Regulatory Assessment Rider				13,108 17				
5	Plus: Proposed Increase to Base Rates				5,880,449 11				
6	Proposed Base Revenue				41,365,673 39				
7	Less: Large General Service - Choice Transportation Flex Base Revenue	[redacted]			0 00				$ 18,559,550
8	Less: Large General Service - Transportation Service Flex Base Revenue				12,982,444 22				$ 6,446 53
9	Less: Large General Service - Choice Transportation Flex IRP Revenue				0 00				
10	Less: Large General Service - Transportation Service Flex IRP Revenue				1,251,428 40				
11	Less: Large General Service - Choice Transportation Flex CEP Revenue				0 00				
12	Less: Large General Service - Transportation Service Flex CEP Revenue				883,686 12				
13	Net Proposed Base Revenue				26,248,114 65				
14	Less: Customer Charge Revenue - Schools	0		**5,282.00**	0 00	0 00		0	0 00
15	Less: Customer Charge Revenue - All other non-flex	2,879		**5,560.00**	16,007,240 00	1,610,886 87	12,869 19	559 53	14,396,353 13
16	Net Volumetric Gas Revenue				10,240,874 65				
17	First 2,000 Mcf (Schedule E-4 1)		0 0	**0.6284**	0 00	0 00			0 00
18	Next 13,000 Mcf (Schedule E-4 1)		0 0	**0.3861**	0 00	0 00			0 00
19	Next 85,000 Mcf (Schedule E-4 1)		0 0	**0.3349**	0 00	0 00			0 00
20	Over 100,000 Mcf (Schedule E-4 1)		0 0	**0.2648**	0 00	0 00			0 00
21	Net Volumetric Gas Revenue - Schools				0 00	0 00			0 00
22	First 2,000 Mcf (Schedule E-4 1)		5,299,662 3	**0.6615**	3,505,726 61	2,048,319 48	34 39%	0 3865	1,457,407 13
23	Next 13,000 Mcf (Schedule E-4 1)		11,988,846 2	**0.4064**	4,872,842 82	2,841,356 55	47 70%	0 2370	2,031,486 27
24	Next 85,000 Mcf (Schedule E-4 1)		5,160,184 8	**0.3525**	1,819,112 14	1,067,126 22	17 91%	0 2068	751,985 92
25	Over 100,000 Mcf (Schedule E-4 1)		0 0	**0.2787**	0 00	0 00	0 00%	0 1635	0 00
26	Net Volumetric Gas Revenue				10,197,681 57	5,956,802 25	100 00%		4,240,879 32
27	Total Base Revenue Charge Increase								**18,637,232.45**
28	Total Infrastructure Replacement Plan Decrease								**(9,904,134.27)**
29	Total Capital Expenditure Program Rider Decrease								**(2,895,842.15)**
30	Total Change in LGS Revenue								**5,837,256.03**

Columbia Gas of Ohio, Inc.
Case No. 21-637-GA-AIR
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2021

HIGHLY CONFIDENTIAL

Line No.		Bills	MCF	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1	**Cooperative Service**								
2	Total Revenue @ Current Rates				291,546 99				
3	Less: Gas Cost Recovery				0 00				
4	Plus: Proposed Increase to Base Rates				36,657 46				
5	Proposed Base Revenue				328,204 45				
6	Less: Cooperative Service CoOpt-Choice Industrial Flex	[redacted]			998 45				
7	Net Proposed Base Revenue				327,206 00				
8	Less: Customer Charge Revenue - All other non-flex	263		**30.00**	7,890 00	0 00		0 00	7,890 00
9	Net Volumetric Gas Revenue			85 0000	319,316 00				
10	First 25 Mcf		6,424 6	**1.0472**	6,727 84	6,100 80	2 10%	0 9496	627 04
11	Over 25 Mcf		324,083 1	**0.9658**	312,999 46	284,447 74	97 90%	0 8777	28,551 72
12	Net Volumetric Gas Revenue		330,507 7		319,727 30	290,548 54	100 00%		29,178 76
13	Total Base Revenue Charge Increase								**37,068.76**
14	Total Infrastructure Replacement Plan Decrease								**0.00**
15	Total Capital Expenditure Program Rider Decrease								**0.00**
16	Total Change in Cooperative Revenue								**37,068.76**

Columbia Gas of Ohio, Inc.
Case No. 21-637-GA-AIR
Monthly Fixed Charge Comparison and Derivation by Rate Class
For the 12 Months Ended December 31, 2022

					Monthly Fixed Riders					
Rate Class	Customer Related Costs (1)	Cost-Based SFV Charge (2)	SFV Charge at Proposed Revenues (3)	Current Monthly Charge	IRP Charge	CEP Charge	Current Monthly Fixed Charges	Current Riders Plus Customer Related Costs	Proposed Monthly Delivery Charge	Percent Change
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
					$/Customer/Month					
SGS/SGTS/FRSGTS	$42.78	$49.35	$46.31	$16.75	$11.98	$5.92	$34.65	N/A	$46.31	33.7%
GS/GTS/FRGTS	$75.40	$293.01	$470.13	$21.16	$108.18	$41.48	$170.82	$225.06	$194.00	13.6%
LGS/LGTS/FRLGTS	$718.77	$7,835.07	$10,022.78	$559.53	$3,440.13	$1,005.85	$5,005.51	$5,164.75	$5,560.00	11.1%
FRCTS	$29.10	$1,102.52	$1,193.47	$0.00	$0.00	$0.00	$0.00	$29.10	$30.00	N/A

(1) From Columbia's Cost of Service Study (see Schedule E-3.1, page 12 of 12, line 443)
(2) At an Equalized Rate of Return (Schedule E-3.2-1, page 3 of 4, line 59 divided by Schedule E-3.2-2, page 2 of 2, line 43)
(3) The SFV charge is lower/higher than the Cost-Based SFV Charge if the rate class receives/provides a current rate subsidy from/to the other rate classes (Schedule E-3.2-1, page 2 of 4, line 30 divided by Schedule E-3.2-2, page 2 of 2, line 43)