

TAB 23

807 KAR 5:001 Section 16(7)(a)

Direct Testimony of

Ronald J. Amen

**COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION**

In the matter of:)
)
ELECTRONIC APPLICATION OF) Case No. 2026-00099
COLUMBIA GAS OF KENTUCKY, INC.)
FOR AN ADJUSTMENT OF RATES;)
APPROVAL OF DEPRECIATION STUDY;)
APPROVAL OF TARIFF REVISIONS; AND)
OTHER RELIEF)

**PREPARED DIRECT TESTIMONY OF
RONALD J. AMEN
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.**

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May 20, 2026

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VERIFICATION OF RONALD J. AMEN

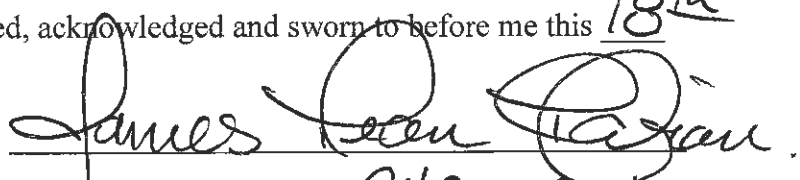
STATE OF WASHINGTON)
)
COUNTY OF KING)

Ronald J. Amen, Board Chairman, Treasurer, and Executive Vice President of Atrium Economics, Inc. being duly sworn, states that he has drafted and/or supervised the preparation of testimony and certain standard filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.



Ronald J. Amen

The foregoing Verification was signed, acknowledged and sworn to before me this 18th day of May 2026, by Ronald J. Amen.



Notary Commission No. 24017231
Commission expiration: 04/02/2028



PREPARED DIRECT TESTIMONY OF RONALD J. AMEN

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1 I. INTRODUCTION

2 Q: **Please state your name and business address.**

3 A: My name is Ronald J. Amen, and my business address is 10 Hospital Center
4 Commons, Suite 400, Hilton Head Island, SC 29926.

5 Q: **What is your current position and what are your responsibilities?**

6 A: I am employed by Atrium Economics, Inc. ("Atrium") as Board Chairman,
7 Treasurer, and Executive Vice President. Atrium is a management consulting
8 and financial advisory firm focused on the North American energy industry.

9 Q: **Please describe your background and professional experience in the energy
10 utility industry?**

11 A: I have over 40 years of experience in the energy utility industry, the last 28
12 years of which have been in the field of utility management and economic
13 consulting. I have advised and assisted utility management, industry trade
14 organizations, and large energy users in matters pertaining to costing and
15 pricing; competitive market analysis; regulatory planning and policy
16 development; resource planning and acquisition; strategic business
17 planning; merger and acquisition analysis; organizational restructuring;
18 new product and service development; and load research studies. I have
19 prepared and presented expert testimony before utility regulatory bodies
20 across North America and have spoken on utility industry issues and

1 activities dealing with the pricing and marketing of gas utility services, gas
2 and electric resource planning and evaluation, and utility infrastructure
3 replacement. Further background information summarizing my work
4 experience, presentation of expert testimony, and other industry-related
5 activities is included in Attachment RJA-1 to my testimony.

6 **Q: Have you previously testified before any regulatory commissions?**

7 A: Yes, a list of the regulatory bodies before which I have testified is included
8 in Attachment RJA-1, including the Kentucky Public Service Commission.

9 **Q: What is the purpose of your testimony?**

10 A: My testimony presents Columbia Gas of Kentucky, Inc.'s ("Columbia" or
11 "Company") Allocated Cost of Service Study ("COSS") and discusses its
12 results. I also present the Company's proposed class revenue
13 apportionment and various rate design proposals filed by Columbia in this
14 proceeding.

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

- 17 • Theoretical Principles of Cost Allocation
- 18 • Columbia's Cost of Service Studies
- 19 • Principles of Sound Rate Design
- 20 • Determination of Proposed Class Revenues

1 • Columbia’s Rate Design Proposals

2 • Customer Bill Impacts

3 **Q: What Filing Requirements will you be supporting?**

4 **A:** I will sponsor and support the following Filing Requirements:

Filing Requirement	Description	Tab
807 KAR 5:001 Section 16(7)(c)	A complete description, which may be filed in written testimony form, of all factors used in preparing the utility’s forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.	34
807 KAR 5:001 Section 16(7)(v)	If gas, electric, sewage or water utility, whose annual gross revenues exceed \$5,000,000 in the division for which a rate adjustment is sought, a cost-of-service study based on methodology generally accepted in industry and based on current and reliable data from single time period	70

<p>807 KAR 5:001 Section 16(8)(n)</p>	<p>A typical bill comparison under present and proposed rates for all classes.</p>	<p>85</p>
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1 **Q: For each of the documents included within the Filing Requirements that**
2 **you are supporting, were they prepared by you or someone working**
3 **under your supervision and did you review each of the documents**
4 **included within the Filing Requirements that you are co-sponsoring?**

5 A: Yes.

6 **Q: Please provide a list of the attachments supporting your testimony.**

7 A: I am sponsoring the following 4 attachments, all of which were prepared
8 by me or under my supervision and direction:

9 Attachment RJA-1 – Resume of Ronald J. Amen

10 Attachment RJA-2 – Cost of Service Study

11 Attachment RJA-3 – Class Revenue Apportionment

12 Attachment RJA-4 – Proposed Rate Design

13 **II. THEORETICAL PRINCIPLES OF COST ALLOCATION**

14 **Q: Why do utilities conduct cost allocation studies as part of the regulatory**
15 **process?**

16 A: There are many purposes for utilities conducting cost allocation studies,
17 ranging from designing appropriate price signals in rates to determining

1 the share of costs or revenue requirements borne by the utility's various
2 rate or customer classes. In this case, an allocated COSS is a useful tool for
3 determining the allocation of Columbia's revenue requirement among its
4 customer classes. It is also a useful tool for rate design because it can
5 identify the important cost drivers associated with serving customers and
6 satisfying their design day demands.

7 Cost of service studies represent a process to analyze which
8 customer or group of customers cause the utility to incur the costs to
9 provide service. The requirement to develop cost studies results from the
10 nature of utility costs. Utility costs are characterized by the existence of
11 common costs. Common costs occur when the fixed costs of providing
12 service to one or more classes, or the cost of providing multiple products to
13 the same class, are shared by customers who use the same facilities and the
14 use by one class precludes the use by another class.

15 Utility costs may be fixed or variable in nature. Fixed costs do not
16 change with the level of throughput. Most non-fuel related utility costs are
17 fixed in the short run and do not vary with changes in customers' loads.
18 This includes the cost of distribution mains and service lines, meters, and
19 regulators. The distribution assets of a gas utility do not vary with the level
20 of throughput in the short run. Variable costs change directly with changes

1 in throughput. In the long run, transmission and distribution main costs
2 vary with either growing design day demand or a growing number of
3 customers.

4 Finally, many utility costs exhibit significant economies of scale.
5 Scale economies result in declining average cost as gas throughput
6 increases and marginal costs below average costs. These characteristics
7 have implications for both cost analysis and rate design from a theoretical
8 and practical perspective. The development of cost studies requires an
9 understanding of the operating characteristics of the utility system. Further,
10 as discussed below, different cost studies provide different contributions to
11 the development of economically efficient rates and the cost responsibility
12 by customer class.

13 **Q: What is the general approach used to develop a COSS?**

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

1 **Q: Are cost of service studies an application of economic theory to cost**
2 **allocation?**

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

15 However, the existence of common costs makes any allocation of
16 costs problematic from a strict economic perspective. This is theoretically
17 true for any of the various utility costing methods that may be used to
18 allocate costs. Theoretical economists have developed the theory of
19 subsidy-free prices to evaluate traditional regulatory cost allocations. Prices
20 are said to be subsidy-free so long as the price exceeds the incremental cost

1 of providing service but is less than stand-alone costs (“SAC”). The logic
2 for this concept is that if customers’ prices exceed incremental cost, those
3 customers contribute to the fixed costs of the utility. All other customers
4 benefit from this contribution to fixed costs because it reduces the cost they
5 are required to bear. Prices must be below the SAC because the customer
6 would not be willing to participate in the service offering if prices exceed
7 SAC.

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

17 **Q: If any allocation of common cost is problematic from a theoretical**
18 **perspective, how is it possible to meet the practical requirements of cost**
19 **allocation?**

1 A: As noted above, the practical reality of regulation often requires that
2 common costs be allocated among jurisdictions, classes of service, rate
3 schedules, and customers within rate schedules. The key to a reasonable
4 cost allocation is an understanding of *cost causation*. Cost causation, as
5 alluded to earlier, addresses the need to identify which customer or group
6 of customers causes the utility to incur particular types of costs. To answer
7 this question, it is necessary to establish a linkage between a local
8 distribution company's ("LDC's") customers and the particular costs
9 incurred by the utility in serving those customers.

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

18 **Q: Why are the relationships between customer requirements, load profiles,**
19 **and usage characteristics significant to cost causation?**

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

9 Customer-related costs are incurred to attach a customer to the
10 distribution system, meter any gas usage, and maintain the customer's
11 account. Customer costs are a function of the number of customers served
12 and continue to be incurred whether or not the customer uses any gas. They
13 include capital costs associated with minimum size distribution mains,
14 services, meters, regulators, and customer service and accounting expenses.

15 Demand- or capacity-related costs are associated with plant that is
16 designed, installed, and operated to meet maximum hourly or daily gas
17 flow requirements, such as the transmission and distribution mains, or
18 more localized distribution facilities that are designed to satisfy individual
19 customer maximum demands. Gas supply contracts also have a capacity

1 related component of cost relative to the Company's requirements for
2 serving daily peak demands and the winter peaking season.

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

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

1 **Q: How does one establish the cost and utility service relationships you**
2 **previously discussed?**

3 A: To establish these relationships, the Company must analyze its gas system
4 design and operations, its accounting records, as well as its system and
5 customer load data (e.g., annual, and peak period gas consumption levels).
6 From the results of those analyses, methods of direct assignment and
7 common cost allocation methodologies can be chosen for all of the utility's
8 plant and expense elements.

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

10 A: The term "direct assignment" relates to a specific identification and
11 isolation of plant and/or expense incurred exclusively to serve a specific
12 customer or group of customers. Direct assignments best reflect the cost
13 causation characteristics of serving individual customers or groups of
14 customers. Therefore, in performing a COSS, the cost analyst seeks to
15 maximize the amount of plant and expense directly assigned to particular
16 customer groups to avoid the need to rely upon other more generalized
17 allocation methods. An alternative to direct assignment is an allocation
18 methodology supported by a special study as is done with costs associated
19 with meters and services.

20 **Q: What prompts the analyst to elect to perform a special study?**

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

8 **Q: How do you determine whether to directly assign costs to a particular**
9 **customer or customer class?**

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

18 **Q: Is it realistic to assume that a substantial portion of the plant and**
19 **expenses of a utility can be directly assigned?**

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

8 **Q: Were direct assignments of plant made in Columbia's COSS?**

9 A: Yes. A special study was performed to directly assign a portion of the
10 specific distribution plant installed to serve Columbia's Main Line Delivery
11 Service customers ("DS-ML"). The costs related to these facilities from the
12 following plant accounts were directly assigned to this class.

- 13 • Account 375.4 – Structures & Improvements
- 14 • Account 376 – Distribution Mains
- 15 • Account 385 – Industrial M & R Station Equipment.

16 **III. COLUMBIA'S COST OF SERVICE STUDIES**

17 **A. Process Steps and Structure of the Cost-of-Service Studies**

18 **Q: Please describe the process of performing Columbia's COSS analysis.**

19 A: Columbia prepared three COSS in this case which are identified as the
20 Customer/Demand study, Demand/Commodity study, and the Average

1 study. All three studies are based on reasonable and generally accepted
2 COSS methodologies but produce varying results.

3 Three broad steps were followed to perform the Company's COSS:
4 (1) functionalization, (2) classification, and (3) allocation. The first step,
5 functionalization, identifies and separates plant and expenses into specific
6 categories based on the various characteristics of utility operation. The costs
7 are functionalized in accordance with the Federal Energy Regulatory
8 Commission (FERC) Uniform System of Accounts.

9 The Company's functional cost categories associated with gas service
10 include Classification of costs, the second step, further separates the
11 functionalized plant and expenses into the three cost-defining
12 characteristics previously discussed: (1) customer, (2) demand or capacity,
13 and (3) commodity.

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

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

19 **A:** Yes. The factors which can influence the cost allocation used to perform a
20 COSS include: (1) the physical configuration of the utility's gas system; (2)

1 the availability of data within the utility; and (3) the regulatory policies and
2 requirements applicable to the utility.

3 **Q: Why are these considerations relevant to conducting Columbia's COSS?**

4 A: It is important to understand these considerations because they influence
5 the overall context within which a utility's cost study was conducted. In
6 particular, they provide an indication of where efforts should be focused
7 for purposes of conducting a more detailed analysis of the utility's gas
8 system design and operations and understanding the regulatory
9 environment in the Commonwealth of Kentucky as it pertains to cost of
10 service studies and gas ratemaking issues.

11 **Q: Please explain why the physical configuration of the system is an**
12 **important consideration.**

13 A: The particulars of the physical configuration of the transmission and
14 distribution system are important to understand the potential influence of
15 these characteristics on cost causation. The specific characteristics of the
16 system configuration, such as, whether the distribution system is a
17 centralized or a dispersed one, should be identified. Other such
18 characteristics are whether the utility has a single city-gate or a multiple
19 city-gate configuration, whether the utility has an integrated transmission

1 and distribution system or a distribution-only operation, and whether the
2 system is a multiple-pressure based or a single-pressure based operation.

3 **Q: What are the specific physical characteristics of Columbia's system?**

4 A: The physical configuration of Columbia's system is a dispersed / multiple
5 city gate, primarily distribution-only and multi-pressure-based system.

6 **Q: What was the source of the cost data analyzed in the Company's COSS?**

7 A: All cost-of-service data has been extracted from the Company's total cost of
8 service (i.e., total revenue requirement) and subsidiary schedules contained
9 in this filing.

10 **Q: How does the availability of data influence a COSS?**

11 A: The structure of the utility's books and records can influence the cost study
12 framework. This structure relates to attributes such as the level of detail,
13 segregation of data by operating unit or geographic region, and the types
14 of load data available. Columbia maintains many detailed plant accounting
15 records for its distribution-related facilities.

16 **Q: How are Columbia's classes structured for purposes of the COSS?**

17 A: The COSS evaluated five customer classes: General Service Residential (GS-
18 Residential), General Service Other (GS-Other), Intrastate Utility Service
19 (IUS), Main Line Delivery Service (DS-ML), and Interruptible Delivery

1 Service (DS/IS). The specific rate schedules contained within each class can
2 be found in Columbia’s COSS Report in Attachment RJA-2.

3 **Q: How do regulatory policies bear upon a utility’s COSS?**

4 A: Regulatory policies and requirements prescribe whether there is a
5 particular approach historically used to establish utility rates in the
6 Commonwealth. Specifically, regulations may set forth the methodological
7 preferences or guidelines for performing cost studies or designing rates
8 which can influence the cost allocation method utilized by the utility.

9 **B. Classification and Allocation of Distribution Mains**

10 **Q: How did the Company’s COSS classify and allocate investment in**
11 **Distribution Mains?**

12 A: In alignment with the past filings made by Columbia, the application of the
13 COSS provides insight into the total cost to serve each rate class using two
14 different methods of allocating distribution mains—the Customer/Demand
15 Study and the Demand/Commodity Study. Columbia believes that both the
16 Customer/Demand and Demand/Commodity Studies are relevant because
17 they provide the outside limits of the reasonable allocation of mains costs
18 to the various classes of service. As such, Atrium performed three Allocated
19 COSS: (1) Customer/Demand Study, (2) Demand/Commodity Study, and

1 (3) Average Study (using an average of the Customer/Demand and the
2 Demand/Commodity allocations).

3 **Q: Were there any other differences in methodology between the Average,**
4 **Demand/Commodity, and Customer/Demand Studies completed in this**
5 **case?**

6 A: No. The only difference among the studies is the application of the
7 distribution mains allocation factors and their impact on the calculation of
8 related allocation factors.

9 **Q: How did the Company's COSS classify and allocate investment in**
10 **Distribution Mains by Demand?**

11 A: The demand-related investment was allocated to the customer classes
12 based on their respective contribution to peak day demand under system
13 design weather conditions, in other words, on a "design day" basis in the
14 Customer/Demand study. In the Demand/Commodity and Average Study,
15 demand costs are allocated on design day demand and throughput.

16 **Q: Please explain the basis for the Company's choice of classification and**
17 **allocation methods under its preferred COSS.**

18 A: It is widely accepted that distribution mains (FERC Account No. 376) are
19 installed to meet both system peak period load requirements and to connect
20 customers to the LDC's gas system. Therefore, to ensure that the rate classes

1 that cause the Company to incur this plant investment or expense are
2 charged with its cost, distribution mains should be allocated to the rate
3 classes in proportion to their peak period load requirements and number of
4 customers.

5 There are two cost factors that influence the level of distribution
6 mains facilities installed by an LDC in expanding its gas distribution
7 system. First, the size of the distribution main (i.e., the diameter of the main)
8 is directly influenced by the sum of the peak period gas demands placed on
9 the LDC's gas system by its customers. Second, the total installed footage
10 of distribution mains is influenced by the need to expand the distribution
11 system to connect new customers to the system. The cost to connect all
12 customers to the distribution system is conceptually the cost of trenching,
13 backfilling, and site restoration under a myriad of installation conditions
14 involved with the construction of a distribution main, exclusive of the cost
15 of pipeline materials. In this conceptual model, the length (i.e., miles) of
16 mains required to connect new customers to Columbia's distribution grid
17 is recognized as a key cost driver. Columbia not only serves urban areas
18 with high population density (e.g., Lexington) but lesser populated rural
19 areas as well, requiring longer distances to serve fewer customers.

1 Construction costs are also impacted by the installation conditions¹
2 associated with each construction project. Therefore, to recognize that these
3 two cost factors influence the level of investment in distribution mains, it is
4 appropriate to allocate such investment based on both peak period
5 demands and the number of customers served by the LDC.

6 **Q: Is the method used by the Company to determine a customer cost**
7 **component of distribution mains a generally accepted technique for**
8 **determining customer costs?**

9 A: Yes. The two most commonly used methods for determining the customer
10 cost component of distribution mains facilities consist of the following: (1)
11 the zero-intercept approach and (2) the most commonly installed,
12 minimum-sized unit of plant investment. Under the zero-intercept
13 approach, a customer cost component is developed through regression
14 analyses to determine the unit cost associated with a zero-inch diameter
15 distribution main. The method regresses unit costs associated with the
16 various sized distribution mains installed on the LDC's gas system against
17 the size (diameter) of the various distribution mains installed. The zero-
18 intercept method seeks to identify that portion of plant representing the

¹ For example, surface material (paved with concrete, paved with asphalt, not paved); presence of other utility infrastructure nearby (water, sewer, underground cable); land and right-of-way acquisition; ground conditions (sand, soil, rock, boulders), etc.

1 smallest size pipe required merely to connect any customer to the LDC's
2 distribution system, regardless of the customer's peak or annual gas
3 consumption.

4 The most commonly installed, minimum-sized unit approach is
5 intended to reflect the engineering considerations associated with installing
6 distribution mains to serve gas customers. That is, the method utilizes
7 actual installed investment units to determine the minimum distribution
8 system rather than a statistical analysis based upon investment
9 characteristics of the entire distribution system.

10 For purposes of determining the customer component of
11 distribution mains to be used in Columbia's COSS, the zero-intercept
12 method was utilized. The zero-intercept method resulted in a 47.42%
13 customer component.

14 **Q: Do the results of the zero-intercept method described above therefore**
15 **support the 47.42% classification of distribution mains as customer**
16 **related, used by the Company?**

17 **A:** Yes. Applying the regression results for the "zero inch" distribution main
18 where plastic mains cost \$38.10 per foot, and steel mains cost \$68.59 per
19 foot, to the Company's total footage of distribution mains results in an

1 investment amount equivalent to approximately 47.42% of the total
2 investment in distribution mains, on a current cost (year 2025) basis.

3 **Q: Would one expect there to be a strong correlation between the number of**
4 **customers served by Columbia and the length of its system of**
5 **distribution mains?**

6 A: Yes. Development of the Company's distribution system over time is a
7 dynamic process. Customers are added to the distribution system on a
8 continuous basis under a variety of installation conditions. Accordingly,
9 this process cannot be viewed as a static situation where a particular
10 customer being added to the system at any one point in time can serve as a
11 representative example for all customers. Rather, it is more appropriate to
12 understand and appreciate that for every situation where a customer can
13 be added with little or no additional footage of mains installed, there are
14 contrasting situations where a customer can be added only by extending
15 the distribution mains to the customer's "off-system" location.

16 Recognizing that the goal is to more reasonably classify and allocate
17 the total cost of Columbia's distribution mains facilities, it is appropriate to
18 analyze the cost causation factors that relate to these facilities based on the
19 total number of customers serviced from such facilities. Accordingly, the
20 concept of using a minimum system approach for classifying distribution

1 mains simply reflects the fact that the average customer serviced by the
2 Company requires a minimum amount of mains investment to receive such
3 service. Thus, it is entirely appropriate to conclude that the number of
4 customers served by Columbia represents a primary causal factor in
5 determining the amount of distribution mains cost that should be assessed
6 to any particular group of customers. One can readily conclude that a
7 customer component of distribution mains is a distinct and separate cost
8 category that has much support from an engineering and operating
9 standpoint.

10 **C. Distribution and General Plant Classification and Allocation**

11 **Q: How were the remaining Distribution Plant costs treated in the COSS?**

12 **A:** As discussed earlier, where possible, costs were directly assigned to the
13 customer classes based on data in the Company's plant records. Weighting
14 factors were developed for plant costs in FERC Account Nos. 380 (Services),
15 381 (Meters) and 385 (Industrial M&R Station Equipment) based on the size
16 and type of the facilities and equipment. The classification and allocation of
17 the remaining account balances of the directly assigned costs discussed
18 earlier were based on the meters and distribution mains allocators,
19 respectively. The costs in Accounts Nos. 374 (Land & Right of Way), 375
20 (Structures & Improvements), and 378 & 379 (Measurement & Regulator

1 Station Equipment – General & City Gate) were classified and allocated
2 based on the average of Design Day and Demand/Commodity allocator, the
3 Design Day Peak allocator, or the Demand/Commodity allocator
4 depending on which of the three studies was being analyzed, as detailed in
5 the COSS report (Schedules 1, 7, and 8 within Attachment RJA-2).

6 **Q: How were the General and Common Plant costs classified and allocated**
7 **in the COSS?**

8 A: General, Intangible, and Common Plant costs were classified and allocated
9 to the customer classes based on an internal allocation factor generated
10 from the results of the classification and allocation of distribution plant
11 costs as shown in the COSS report (Schedule 1 within Attachment RJA-2).

12 **D. Operation & Maintenance, Customer Accounts & Services, and**
13 **Administrative & General Expenses**

14 **Q: How were O&M expenses classified and allocated in the COSS?**

15 A: Generally, the classification and allocation of the Operation & Maintenance
16 (O&M) expenses followed the treatment of the related plant accounts. For
17 example, the treatment of Account No. 879 (Customer Installations
18 Expense), followed the weighted meters allocator.

19 **Q: Please describe the classification and allocation of Customer Accounts**
20 **and Customer Service expenses in the COSS.**

1 A: Customer accounts and services expenses were classified as customer-
2 related costs and allocated based on the average number of distribution
3 customers by class. One exception to this treatment was Account No. 904
4 (Uncollectible Accounts). Uncollectible accounts expenses were assigned to
5 the customer classes based on an average of net uncollectible expense
6 amounts over the historical twelve-month period ending December 31,
7 2025, with net residential uncollectible expenses directly assigned to that
8 customer class. The net non-residential uncollectible expense amounts were
9 allocated by the respective customer counts in the non-residential classes.

10 **Q: Please explain the treatment of Administrative and General (“A&G”)**
11 **expenses in the COSS.**

12 A: The majority of the A&G expenses were classified and allocated based on
13 the internally generated allocation factor of total O&M expenses, excluding
14 gas supply related costs, Uncollectible expense and A&G. Taxes Other than
15 Income Taxes and their corresponding allocation basis [in brackets] include
16 Property taxes [Distribution Plant] and Payroll & Other Taxes [Labor].
17 Income taxes were allocated based on Rate Base.

18 **E. Cost of Service Study Results**

19 **Q: Please explain the COSS information contained in Attachment RJA-2.**

20 A: The following is the list of Schedules included in Attachment RJA-2:

1 Schedule 1 – Account Balances, Functionalization, Classification and
2 Allocation – displays revenue requirements presented by FERC accounts
3 with corresponding selections of functions, classifications, and allocation
4 methods applied to the accounts for the Average Study.

5 Schedule 2 – External Allocation Factors - depicts the derivation of external
6 allocation factors for the Average Study that are explained in detail in
7 Attachment RJA-2.

8 Schedule 3 – Internal Allocation Factors - depicts the derivation of internal
9 allocation factors for the Average Study that are explained in detail in
10 Attachment RJA-2.

11 Schedule 4 – Cost of Service and Rate of Return under Present and Proposed
12 Rates – a summary of the Average Study cost to serve as compared to
13 revenues under present and proposed rates.

14 Schedule 5 – Cost of Service Allocation Study Detail by Account – a detailed
15 cost of service study presented by the FERC accounts for the individual rate
16 classes for the Average Study.

17 Schedule 6 – Functionalized and Classified Rate Base and Revenue
18 Requirement, and Unit Costs by Customer Class - a summary of
19 functionalized and classified rate base and revenue requirements along
20 with derived unit cost by customer class for the Average Study.

1 Schedule 7 – Customer-Demand Study Summary Schedules (Account
2 Balances, Functionalization, Classification and Allocation, Functionalized
3 and Classified Rate Base and Revenue Requirement, and Unit Costs by
4 Customer).

5 Schedule 8 – Demand-Commodity Study Summary Schedules (Account
6 Balances, Functionalization, Classification and Allocation, Functionalized
7 and Classified Rate Base and Revenue Requirement, and Unit Costs by
8 Customer).

9 **Q: Please summarize the results of the Average Study COSS.**

10 **A:** As shown in Schedule 4 within Attachment RJA-2, the overall rate of return
11 for Columbia’s natural gas service is 3.75% at present rates, based on the
12 results of gas operations for the 12 months ended December 31, 2027,
13 adjusted for known and measurable changes. The returns by customer class
14 at current rates are shown in Table 1 below:

15 **Table 1 – Class Rates of Return at Current Rates**

Customer Class	Rate of Return at Current
GS Residential	1.68%
GS Other	7.79%
IUS	9.34%
DS-ML	88.88%
DS-IS	7.59%

16

1 **IV. PRINCIPLES OF SOUND RATE DESIGN**

2 **Q: Please identify the principles of rate design you rely upon as the basis for**
3 **rate design proposals.**

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

- 6 • Efficiency;
- 7 • Cost of Service and Value of Service;
- 8 • Stability;
- 9 • Non-Discrimination;
- 10 • Administrative Simplicity; and
- 11 • Balanced Budget.

12 These rate design principles draw heavily upon the “Attributes of a
13 Sound Rate Structure” developed by James Bonbright in Principles of
14 Public Utility Rates. Each of these principles plays a significant role in
15 analyzing the rate design proposals of Columbia.

16 **Q: Please discuss the principle of efficiency.**

17 A: The principle of efficiency broadly incorporates both economic and
18 technical efficiency. As such, this principle has both a pricing dimension
19 and an engineering dimension. Economically efficient pricing promotes
20 good decision-making by gas producers and consumers, fosters efficient
21 expansion of delivery capacity, results in efficient capital investment in
22 customer facilities, and facilitates the efficient use of existing gas pipeline,

1 storage, transmission, and distribution resources. The efficiency principle
2 benefits stakeholders by creating outcomes for regulation consistent with
3 the long-run benefits of competition while permitting the economies of
4 scale consistent with the best cost of service. Technical efficiency means that
5 the development of the gas utility system is designed and constructed to
6 meet the design day requirements of customers using the most economic
7 equipment and technology consistent with design standards.

8 **Q: Please discuss the cost of service and value of service principles.**

9 A: These principles each relate to designing rates that recover the utility's total
10 revenue requirement without causing inefficient choices by consumers. The
11 cost-of-service principle contrasts with the value of service principle when
12 certain transactions do not occur at price levels determined by the
13 embedded cost of service. In essence, the value of service acts as a ceiling
14 on prices. Where prices are set at levels higher than the value of service,
15 consumers will not purchase the service. This principle puts the concept of
16 SAC, discussed earlier, into practice.

17 **Q: Please discuss the principle of stability.**

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

1 **Q: Please discuss the concept of non-discrimination.**

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

6 This principle recognizes that the ratemaking process requires
7 discrimination where there are factors at work that cause the discrimination
8 to be useful in accomplishing other objectives. For example, considerations
9 such as the location, type of meter and service, demand characteristics, size,
10 and a variety of other factors are often recognized in the design of utility
11 rates to properly distribute the total cost of service to and within customer
12 classes. This concept is also directly related to the concepts of vertical and
13 horizontal equity. The principle of horizontal equity requires that “equals
14 should be treated equally” and vertical equity requires that “unequals
15 should be treated unequally.” Specifically, these principles of equity
16 require that where cost of service is equal – rates should be equal and,
17 where costs are different – rates should be different.

18 **Q: Please discuss the principle of administrative simplicity.**

19 A: The principle of administrative simplicity as it relates to rate design
20 requires prices to be reasonably simple to administer and understand. This

1 concept includes price transparency within the constraints of the
2 ratemaking process. Prices are transparent when customers are able to
3 reasonably calculate and predict bill levels and interpret details about the
4 charges resulting from the application of the tariff.

5 **Q: Please discuss the principle of the balanced budget.**

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

12 **Q: Can the objectives inherent in these principles compete with each other
13 at times?**

14 A: Yes, like most principles that have broad application, these principles can
15 compete with each other. This competition or tension requires further
16 judgment to strike the right balance between the principles. Detailed
17 evaluation of rate design alternatives and rate design recommendations
18 must recognize the potential and actual competition between these
19 principles. Indeed, Bonbright discusses this tension in detail. Rate design

1 recommendations must deal effectively with such tension. For example, as
2 noted above, there are tensions between cost and value of service principles.

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

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

19 In the case of an LDC such as Columbia for residential and small
20 commercial customers, the combination of scale economies and class

1 homogeneity may permit the use of a single fixed monthly charge that
2 meets all of the requirements for an efficient rate that recovers the utility's
3 revenue requirement that is derived on an embedded cost basis. For larger
4 customers, a combination of these elements permits proper price signals
5 and revenue recovery; however, the tariff design becomes more difficult to
6 structure and will no longer meet the requirements of simplicity. Therefore,
7 sacrificing some economic efficiency for a customer class in order to
8 maintain simplicity represents a reasonable compromise. For larger
9 customers, the added complexity of a demand charge may not be a concern.
10 Further, for the largest customers, the cost of metering is customer-specific,
11 and each customer creates its own unique requirements for gas distribution
12 service based on factors such as distance from the utility's city gate,
13 pressure requirements, and contract demand levels.

14 **Q: Are there other potential conflicts?**

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

19 **Q: Please summarize Bonbright's three primary criteria for sound rate**
20 **design.**

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

- 3 • Capital Attraction
- 4 • Consumer Rationing
- 5 • Fairness to Ratepayers

6 These three criteria are a subset of the list of principles above and serve to
7 emphasize fundamental considerations in designing public utility rates.

8 Capital attraction is a combination of an equitable rate of return on rate base
9 and the reasonable opportunity to earn the allowed rate of return.

10 Consumer rationing requires that rates discourage wasteful use and
11 promote all economically efficient use. Fairness to ratepayers reflects
12 avoidance of undue discrimination and equity principles.

13 **Q: How are these principles translated into the design of retail gas rates?**

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

- 17 • System cost characteristics such as established in the COSS required
18 by the Commission, or embedded customer, demand, and
19 commodity-related costs by type of service;
- 20 • Customer load characteristics such as peak demand, load factor,
21 seasonality of loads, and quality of service;

- 1 • Market considerations such as elasticity of demand, competitive fuel
2 prices, end-use load characteristics, and LDC bypass alternatives;
3 and
- 4 • Other considerations such as the value of service ceiling/marginal
5 cost floor, unique customer requirements, areas of underutilized
6 facilities, opportunities to offer new services and the status of
7 competitive market development.

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

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

22 **Q: Are there additional considerations in the development of rates?**

1 A: Yes. Prior to making any decisions and forming recommendations related
2 to the design of rates for the residential class, I performed a detailed review
3 of customer class usage characteristics.

4 **A. Residential Customer Class Characteristics**

5 **Q: Did you review the usage characteristics of the residential class to inform**
6 **the Company's proposed rate design?**

7 A: Yes. Specifically, Atrium was provided with monthly residential customer
8 usage data. While the majority of the analysis focused on the 2025 calendar
9 year, one chart was produced that spanned February 2024 to January 2026
10 (24 months). The results of our analysis are primarily based on one year
11 (2025) monthly residential customer data. Included within this data was not
12 only monthly usage by customer, but also key differentiating features of the
13 customers that allowed me to identify subsets of the residential population
14 for more in-depth comparative analytics related to how low-income ("LI")
15 customers (customers who are enrolled in one or more of the assistance
16 programs offered by the Company)² compare to the rest of the general
17 residential ("GR" or "non-low-income") customer population.

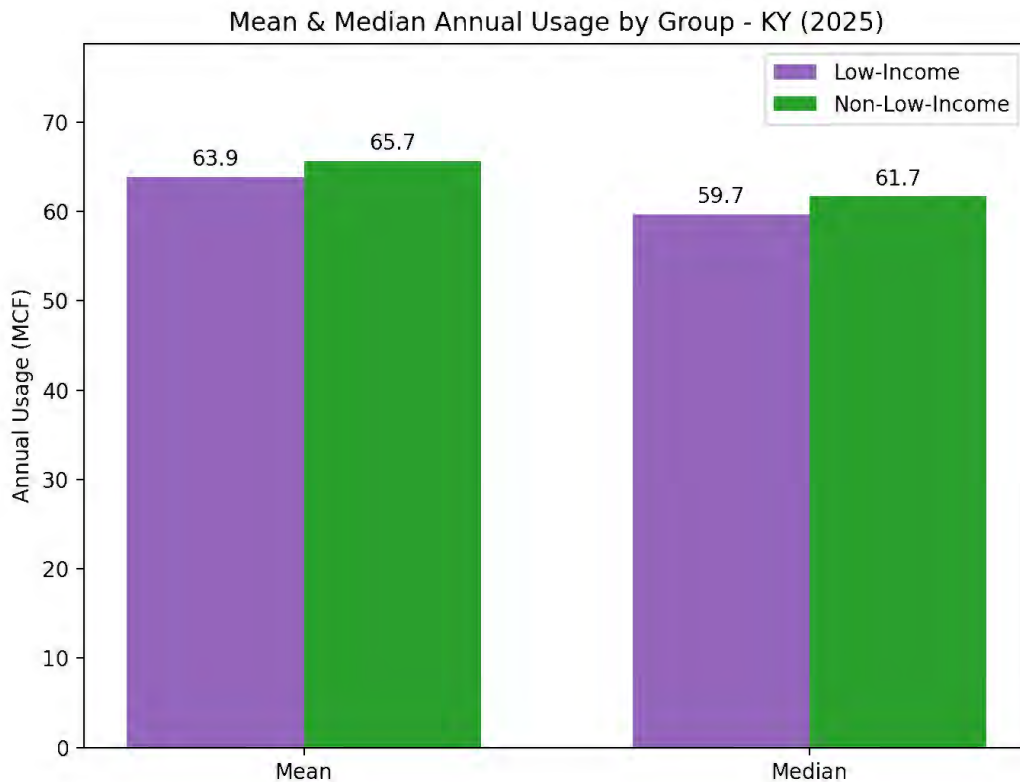
18 **Q: Please summarize your key findings.**

² Low-income customers are identified based on their enrollment in one or more Company-administered assistance programs during the calendar year 2025.

1 A: Of particular interest, the result of my analysis presented in Figure 1 below
2 demonstrates that LI customers tend to consume slightly less natural gas
3 than the GR population. While low-income customers on average have a
4 slightly lower average/median annual usage than non-low-income
5 customers, there is a limited difference, if any, in their seasonal usage,
6 discussed further below.

7 In addition, my analysis shows that LI customers tend to have higher
8 energy usage per square foot, which indicates they live in less efficient
9 dwellings in terms of energy consumption per square foot.

10 **Figure 1 – Comparison of Residential Low-Income and Non-Low-**
11 **Income Annual Usage**



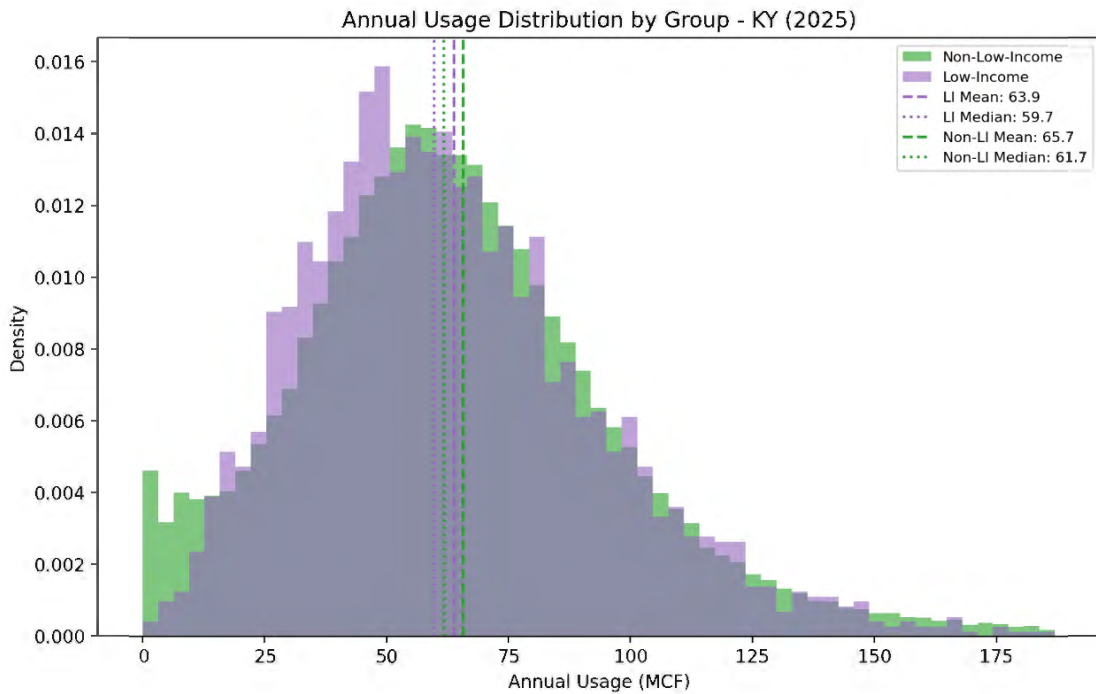
12

1 **Q: Please describe the analysis and results in more detail.**

2 A: Some of this information becomes easier to understand through graphical
3 representation as well. Most of the initial work centered around creating
4 analysis-ready datasets which involved joining together various individual
5 datasets provided by Columbia. These included individual customer
6 billing records from the Company's billing system, Geographic Information
7 System ("GIS") records, which included property record information like
8 living-space square footage, and indicators of customers actively enrolled
9 in one or more Company-provided assistance programs. This was
10 combined with other information regarding the Company's rate schedules
11 and service territory. Once the multiple sources of data were combined into
12 a single dataset, the next step was to validate some of the data
13 characteristics, such as number of customer bills by month and year, high-
14 level usage statistics, assistance enrollment counts, etc. This validation step
15 involved cross-referencing the high-level Atrium-calculated summary
16 statistics with data summaries prepared by the Company for use in the 2024
17 rate proceeding. The Company confirmed alignment between Atrium's
18 numbers and their internal reference points. Statistics such as average
19 usage, monthly usage, and usage per square foot of living space were then
20 computed for the LI group and the non-low-income group. A histogram of

1 each customer's annual usage by group illustrates similar annual usage
2 profiles between the LI and non-low-income populations as shown in
3 Figure 2, below.

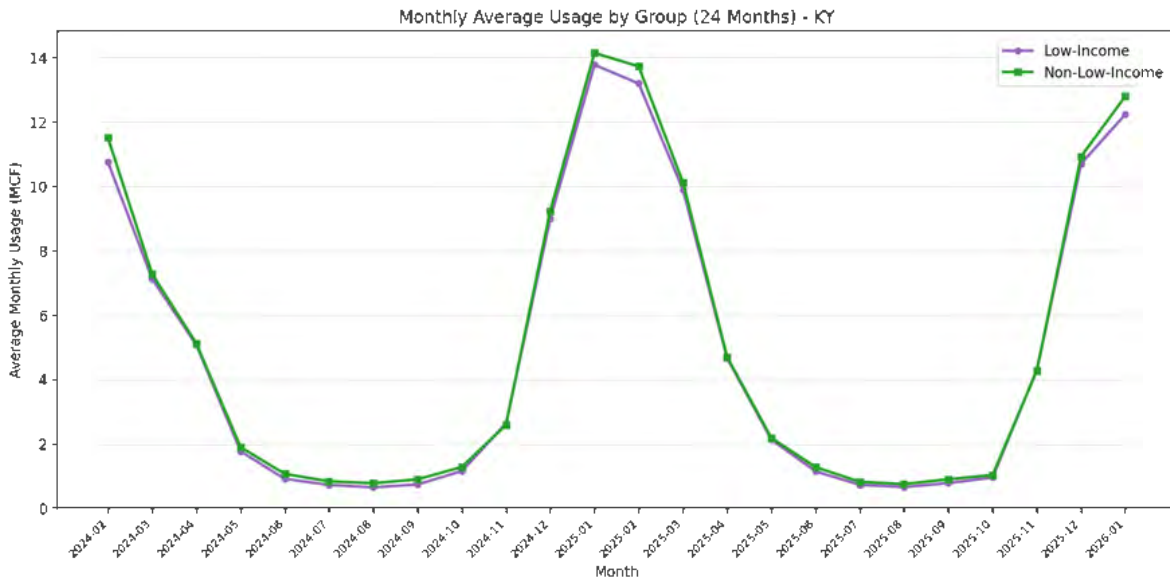
4 **Figure 2 – Annual Residential Usage Distribution by Group**



5
6 As shown in Figure 3 below, it is evident that while the pattern of usage
7 (that is the seasonality characteristics) is very similar between the LI and
8 GR customers, the actual levels of consumption differ whereby the LI
9 customers tend to use slightly less gas than GR customers, especially during
10 the heating months.

1

Figure 3 – Monthly Residential Average Usage Patterns by Group



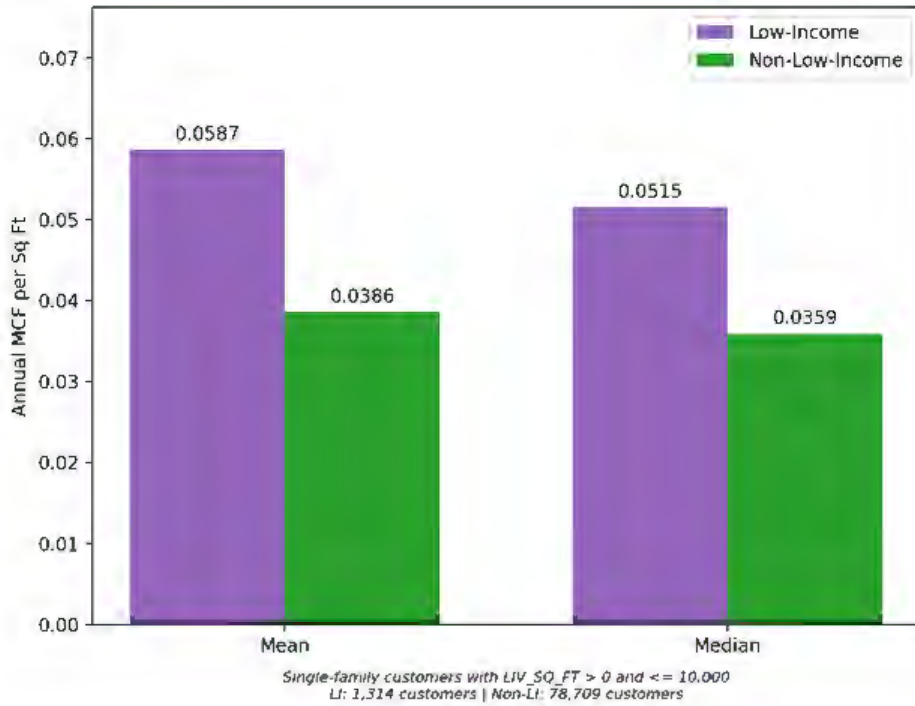
2

3 **Q: You also mentioned analyzing usage per square foot of living space,**
4 **please elaborate further.**

5 **A:** The Company subscribes to a data service to obtain tax assessor data for
6 addresses within its service territory from a third-party data provider. This
7 data includes, among other data points, the square footage of living space
8 for many (though not all) of the addresses in the service territory. Using this
9 information, differences in the energy intensity (i.e., how much energy is
10 used per square foot of living space) between the LI and GR customer
11 segments were estimated. The energy intensity analysis revealed that the LI
12 customer segment tends to use more natural gas per square foot compared
13 to the GR customers, reinforcing the benefits of the Company's

1 weatherization program that can impact the efficiency and energy intensity
2 of dwellings. I have summarized this information in Figure 4 below.

3 **Figure 4 – Residential Usage Intensity**



4

5 **Q: What can you conclude from this analysis?**

6 A: The usage characteristics of Columbia’s residential customers demonstrate
7 a similar usage pattern for most customers with an observable seasonal
8 trend for gas heating. This characteristic is present both for LI customers
9 and non-LI GR customers. A key difference is the level of average usage
10 between these two customer segments with the LI customers using, on
11 average for 2025, approximately 43% when looking at mean and 52% when
12 looking at median, greater volumes of gas than the non-LI GR customers
13 and the differential persists when looking at overall usage and on a monthly

1 basis. This means that during the heating months, the LI customers are
2 experiencing greater volumes than the non-LI GR customers and can see a
3 greater seasonal volatility of bills due to the volumetric rate design. Upon
4 examination, one potential cause for these phenomena is that the LI
5 customers experience a usage per square foot of living space that is
6 approximately 52% greater than the GR customers, indicating the energy
7 intensity of LI dwellings are higher (e.g., less efficient, different household
8 sizes/demographics). Taking all of this information together indicates that
9 residential customers, including LI customers, will benefit through reduced
10 month-to-month bill volatility from a rate design that reduces the amount
11 fixed costs recovered through the volumetric charge as much as possible.

12 **V. DETERMINATION OF PROPOSED CLASS REVENUES**

13 **Q: Please describe the approach followed to allocate Columbia's proposed**
14 **revenue increase of \$35,968,302 to its customer classes.**

15 A: As just described, the apportionment of revenues among customer classes
16 consists of deriving a reasonable balance between various criteria or
17 guidelines that relate to the design of utility rates. The various criteria that
18 were considered in the process included: (1) cost of service; (2) class
19 contribution to present revenue levels; and (3) customer impact

1 considerations. These criteria were evaluated for Columbia's customer
2 classes.

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

5 A: Yes. Using Columbia's proposed revenue increase, and the results of its
6 COSS, I evaluated options for the assignment of that increase among its
7 customer classes and, in conjunction with Columbia's personnel and
8 management, decided upon one of those options as the preferred resolution
9 of the interclass revenue issue. The benchmark option that I evaluated under
10 Columbia's proposed total revenue level was to adjust the revenue level for
11 each customer class so that the revenue-to-cost for each class was equal to 1.00
12 (Unity), as shown in Attachment RJA-3, Class Revenue Apportionment,
13 under *Revenues at Equalized Rates of Return*. As a matter of judgment, it was
14 decided that this fully cost-based option was not the preferred solution to the
15 interclass revenue issue. This decision was also made in consideration of the
16 Bonbright rate design criteria discussed earlier. It should be pointed out;
17 however, that those class revenue results represented an important guide for
18 purposes of evaluating subsequent rate design options from a cost-of-service
19 perspective.

1 A second option I considered was assigning the increase in revenues
2 to Columbia's customer classes based on an equal percentage basis of its
3 current non-gas revenues (see *Scenario B, Equal Percentage Increase on Gas*
4 *Service Revenue*, in Attachment RJA-3). By definition, this option resulted in
5 each customer class receiving an increase in revenues. However, when this
6 option was evaluated against the COSS results (as measured by changes in
7 the revenue-to-cost ratio for each customer class); there was no movement
8 toward cost for most of Columbia's customer classes (*i.e.*, there was no
9 convergence of the resulting revenue-to-cost ratios towards unity). In fact, the
10 disparity in cost responsibility between the classes was widened. Together
11 with the fully cost-based option, it defined a range of results that provides
12 further guidance to develop Columbia's class revenue proposal.

13 **Q: What was the result of this process?**

14 A: After further discussions with Columbia, the Company concluded the second
15 option, *Scenario B, Equal Percentage Increase on Gas Service Revenue*, was the
16 preferred solution to the interclass revenue issue. The resulting class rates of
17 return are shown in Table 2 below.

1

Table 2 – Class Rates of Return at Proposed Rates

Customer Class	Rate of Return at Current	Rate of Return at Proposed
GS Residential	1.68%	5.86%
GS Other	7.79%	12.65%
IUS	9.34%	14.07%
DS-ML	88.88%	112.64%
DS-IS	7.59%	12.10%
System Total	3.75%	8.15%

2

3 In summary, the Company’s preferred revenue allocation approach resulted
4 in meaningful movement of the GS-Residential class revenue-to-cost ratio to
5 0.91, toward a range of reasonableness to unity or 1.00, while requiring an
6 equivalent percentage of revenue increase responsibility from all customer
7 classes for the Company’s proposed total revenue requirement. From a class
8 cost of service standpoint, this type of revenue to cost responsibility for all
9 classes approximated their prior parity ratio levels under current rates and no
10 reduction in the existing interclass rate subsidies.

11 **VI. COLUMBIA’S RATE DESIGN PROPOSALS**

12 **Q: What is Columbia’s vision for its rate design?**

13 A: Based upon the principles of sound rate design discussed earlier, the
14 Company envisions a rate design that aligns its (revenue allocation and)
15 rate design with its cost of service (i.e., cost-based rates). In doing so, this

1 will better ensure that customers are paying for their cost of energy services
2 and result in Company rates that are more equitable, understandable, lead
3 to more stable utility bills, and send the appropriate price signals to its
4 customers which also promotes rational conservation.

5 From the perspective of the customer, cost-based rates provide a
6 more reliable means of determining future levels of natural gas costs. If
7 rates are based on factors other than the cost to serve, it becomes much more
8 difficult for customers to translate expected utility-wide cost changes, such
9 as expected increases in overall revenue requirements, into changes in the
10 rates charged to particular customer classes and to customers within the
11 class. For larger customers, this situation reduces the attractiveness of
12 expansion, as well as continued operations, in the utility's service territory
13 because of the customer's limited ability to plan and budget for future
14 natural gas costs.

15 From the perspective of the utility, when rates are closely tied to
16 costs, the impact on the utility's earnings due to changes in customer usage
17 patterns will be minimized. Rates that are designed to track changes in the
18 level of costs result in revenue changes that mirror cost changes. Thus, cost-
19 based rates provide an important enhancement to a utility's earnings
20 stability, reducing its need to file for frequent rate increases. A key element

1 within cost-based rate design is a Straight-Fixed-Variable (“SFV”)
2 characteristic, which perfectly aligns fixed costs - costs that do not change
3 with energy usage - with fixed charges and variable costs - costs that do
4 change due to energy usage - with variable charges. However, the
5 Company recognizes that this vision is a departure from current practice
6 and should be implemented over the course of a few rate proceedings.

7 **Q: Please summarize the rate design changes Columbia has proposed in this**
8 **rate proceeding.**

9 A: In general, Columbia’s rate design strategy is to update rates to be more
10 cost-based, to better reflect the Company’s cost of providing natural gas
11 distribution service to its customers by increasing the recovery of customer
12 and demand-related costs through fixed charges.

13 The current residential fixed charge of \$21.25 per month recovers
14 39% of customer related costs, resulting in volumetric rates that exceed the
15 cost of providing gas distribution services. The Company has proposed
16 monthly customer charges at levels that reflect movement toward each
17 customer class’s full customer-related cost responsibility with a
18 compensating decrease to volumetric rates. The Company utilized the
19 Customer Based Costs analysis from the COSS to identify costs related to
20 providing both monthly distribution service to customers (customer related

1 costs) and annual levels of distribution capacity (demand related costs). The
2 level of customer related costs is shown for the Residential class of
3 customers in the Unit Cost Analysis to be \$52.81 per customer per month
4 and the combined customer and demand related costs to be \$76.65 per
5 customer per month.

6 For GS-Other customers, the Company has proposed to increase
7 both the monthly customer charge and the volumetric rates in
8 approximately the same proportion of the proposed increase for each
9 GSO/GTO/GDS rate schedule.

10 **Q: Why is setting customer charges in alignment with the fixed cost of**
11 **service an important outcome of ratemaking?**

12 A: These proposed customer charges help to reduce customer bill volatility,
13 alleviate a significant portion of the instability in the Company's margin
14 recovery, are fair to customers, are easily understood, convey more
15 appropriate price signals with respect to recovery of fixed distribution
16 costs, benefit low-income customers that have higher than average use, and
17 are not regressive in application to low-income customers who may have
18 little control over their use of energy by recovering more in volumetric
19 charges. Establishing higher monthly fixed charges helps to equalize the
20 contribution each customer within a class makes towards recovery of the

1 fixed costs attributable to this class. This method of cost recovery is
2 preferable to including such costs in the volumetric block prices, which has
3 the effect of causing some customers to pay too much while others pay too
4 little.

5 The fixed customer charges provide for recovery of a portion of the
6 Company's fixed costs, which are incurred solely because of the existence
7 of customers connected to the system. These costs, such as the expense of
8 reading meters and billing, occur regardless of whether natural gas is used
9 and are not related to demands placed on the system. The proposed
10 customer charge increases will also help to ensure recovery by the
11 Company of a greater portion of its fixed costs of providing service.
12 Inasmuch as costs are not related to usage, they should be recovered to the
13 extent possible through a tariff mechanism that does not depend upon
14 volumetric billing.

15 In terms of understandability, customers easily understand fixed
16 cost charges and are used to these pricing structures in their everyday lives.
17 Because these costs do not vary with the customer's usage, it is perfectly
18 understandable that the charge should not vary as well. It is intuitively
19 obvious that a customer should not pay more for being a customer when

1 the weather is hot and conversely should not pay less when the weather is
2 cold.

3 **Q. What criteria were utilized to determine whether a \$32.00 customer**
4 **charge for the residential customers is appropriate?**

5 A. The residential class does not have a demand charge, so all distribution
6 margin revenues are recovered through either the monthly customer
7 charge or the volumetric charge. This is nearly universal across the utility
8 industry, where some commercial and industrial rate classes may have
9 demand charges but rarely are they present or introduced for residential
10 customers. Introducing a demand charge for residential customers is not
11 viable given current billing processes, and concerns relating to
12 administrative billing complexity and customer understanding. Given the
13 discussion above relating to the fixed cost nature of Columbia's costs and
14 the usage pattern of low-income customers, the Company is proposing a
15 higher customer charge, balancing the principles of rate design discussed
16 earlier (e.g., fairness, stability, and consumer rationing/economic
17 efficiency). After reviewing the current level of the customer charge for
18 residential customers at \$21.25, and the relative unit cost for customer
19 related and demand related costs, it was determined a reasonable
20 movement is a \$32.00 monthly customer charge for residential customers.

1 This allows some of these fixed distribution costs to be recovered through
2 a fixed monthly customer charge rather than a volumetric charge, without
3 introducing a demand charge for residential customers. The \$32.00
4 customer charge was derived by recovering the proposed increase to the
5 residential class fully from the customer charge with only a modest change
6 to the volumetric charge to account for rounding.

7 **Q: Please describe why an increase to the customer charge is important.**

8 A: This becomes particularly important when a customer considers different
9 options relating to alternative fuels and investments in conservation and
10 energy efficiency, as these decisions are fundamental functions of usage.
11 These decisions can be distorted when non-usage-related fixed costs are
12 collected on a usage basis. Further, without proper price signals, the
13 economic markets that comprise materials, goods, and services that are
14 inputs and outputs to energy products and services are distorted.
15 Consequently, companies and people cannot make the proper decision to
16 maximize their preferences on allocating their limited resources of time and
17 money. It is economically inefficient when fixed distribution costs are
18 recovered on a usage basis, and customers implement energy efficiency
19 measures reducing their contribution to fixed costs with no corresponding
20 reduction in the fixed costs of providing service. In short, incorrect pricing

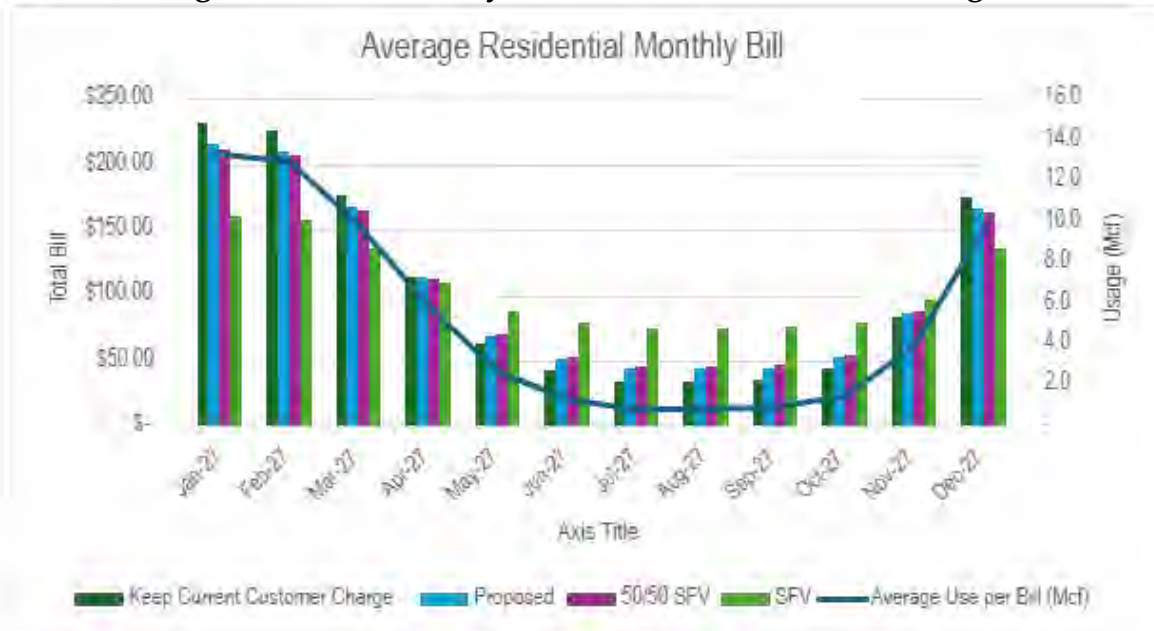
1 results in an incorrect price signal for which consumers may act, resulting
2 in savings for a customer that does not align with decreased costs to the
3 system.

4 **Q: Do fixed monthly charges allow for greater predictability in household**
5 **budgets?**

6 A: Yes. Aligning the utility bills to mimic the way those costs are incurred
7 (similar to car payments and vehicle fuel) will provide a greater
8 understanding of utility bills, reduce volatility, and allow for easier
9 household budgeting due to the enhanced predictability of utility service
10 costs. Figure 4 below shows the average monthly bill for base rate costs and
11 cost of gas usage for a typical residential customer under a range of revenue
12 neutral customer and volumetric charge combinations. It is easy to observe
13 the month-to-month variations is greater in customer bills when more fixed
14 costs are recovered through the volumetric rate rather than a fixed customer
15 charge. The amount of the bill related to utility fixed costs becomes more
16 consistent from month to month as well.

1

Figure 4 – Bill Stability Benefits of Increase Fixed Charge

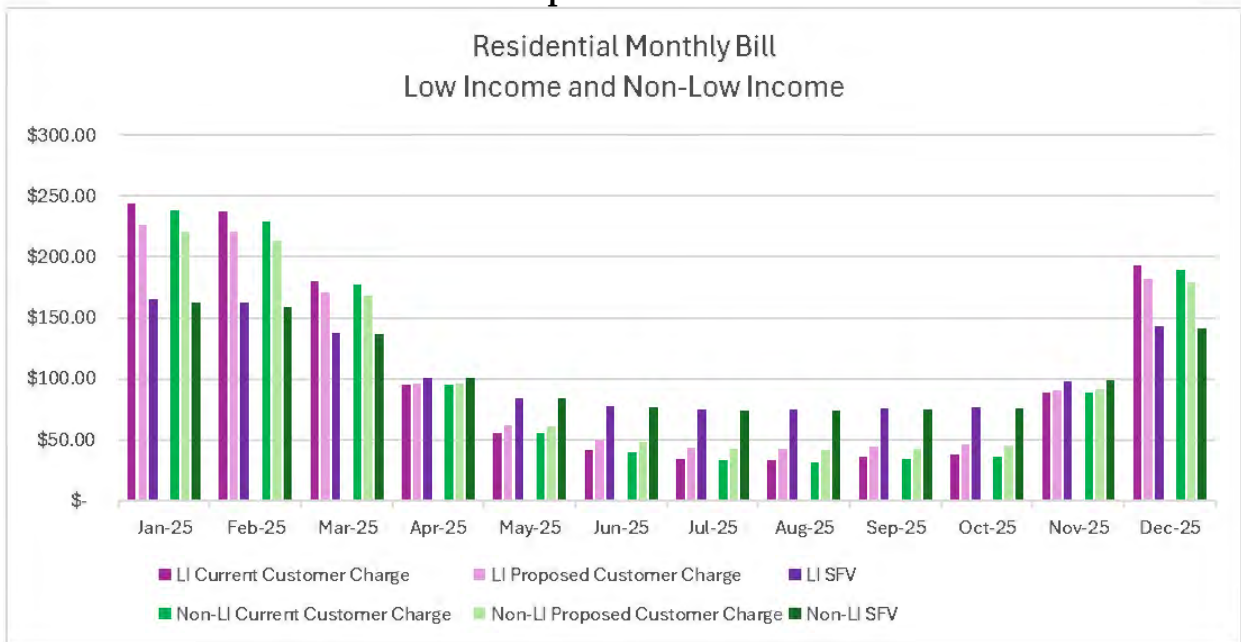


2

3 **Q: How will the Company’s proposal impact the average low-income**
4 **customer?**

5 **A:** As discussed above, the average low-income customer uses less natural gas
6 than the average non-low-income residential customer. Both low-income
7 and non-low-income residential customers have similar seasonal usage
8 patterns. Figure 5 below provides a similar look at the bill stability benefits
9 of different customer charges for low-income and non-low-income
10 customers. Both low-income and non-low-income customers will see
11 greater bill stability under a rate design with higher recovery of fixed costs
12 through a customer charge.

1 **Figure 5: Bill Stability Benefits of Increase Fixed Charge Low Income**
 2 **compared to non-LI**



3
 4 **Q: Why is it reasonable to recover fixed costs through fixed charges for**
 5 **residential customers?**

6 **A:** The vast majority of household expenses are fixed costs that allow for easier
 7 budgeting by households. For example, following is a list of common
 8 household expenses that are typically paid as a fixed monthly charge:

- 9 • Mortgage or Rent: Monthly payments for your home.
- 10 • Property Taxes: Often included in mortgage payments or
- 11 paid separately.
- 12 • Homeowners or Renter’s Insurance: Regular premiums for
- 13 protecting your home and belongings.
- 14 • Internet and Cable: Monthly fees for internet and cable
- 15 television services.
- 16 • Phone Bills: Costs for landline or mobile phone services.

- 1 • Car Payments: Monthly installments for car loans or leases.
- 2 • Car Insurance: Regular premiums for vehicle insurance.
- 3 • Health Insurance: Monthly premiums for medical coverage.
- 4 • Day Care / Child Care / Tuition: Monthly fees for childcare,
- 5 school, etc.

6 These expenses are paid through fixed monthly or periodic charges.

7 Additionally, another characteristic of these services is that the expenses
8 must be paid ahead of (or contemporaneously with) the delivery of the
9 service, not after the fact.

10 Not included in this list are expenses for electric, gas and water utility bills
11 (while cable and internet are included), food and vehicle fuel, while
12 discretionary, are necessities for most households.

13 **Q: How does the proposed customer charge for residential customers**
14 **compare to similar fixed fees for other essential services?**

15 A: The proposed increase in the customer charge aligns with the structure of
16 other essential services that customers regularly pay for such as internet,
17 TV, and mobile phone services. These industries typically charge flat
18 monthly fees that cover infrastructure, maintenance, and service
19 availability, regardless of usage levels.

1 For example, a standard internet service plan in the Lexington area
2 includes a fixed charge ranging from \$24.99 to \$90³ per month, covering
3 network access and service availability, and may also include equipment
4 and customer support, regardless of how much data is used. Similarly,
5 cable and satellite television providers charge a flat monthly fee ranging
6 from \$45 to \$175⁴ for service availability, with tiers based on the number of
7 channels and programming packages selected. Cellphone service providers
8 also follow a similar model, where customers pay a fixed monthly fee
9 ranging from \$50 to \$90⁵ per line for access to the wireless network,
10 customer support, and related services, regardless of the level of usage in
11 any given month. Natural gas service operates similarly, requiring a stable
12 infrastructure to ensure uninterrupted service to all customers, regardless
13 of individual usage patterns.

³ [Spectrum \(fiber\) \\$30-\\$70 per month \[https://www.spectrum.com/locations/internet-wifi-service/lexington-ky-i172\]](https://www.spectrum.com/locations/internet-wifi-service/lexington-ky-i172); [Metronet \(fiber\) \\$60-\\$80 per month \[https://metroconet.com/city/lexington\]](https://metroconet.com/city/lexington); [Kinetic \(fiber\) \\$24.99-\\$89.99 per month \[https://www.gokinetic.com/locations/ky/lexington\]](https://www.gokinetic.com/locations/ky/lexington); [AT&T \(fiber\) \\$45-\\$70 per month \[https://www.att.com/local/internet/kentucky/lexington\]](https://www.att.com/local/internet/kentucky/lexington); [T-Mobile \(fiber\) \\$55-\\$85 per month \[https://www.t-mobile.com/home-internet/fiber/city/ky/lexington\]](https://www.t-mobile.com/home-internet/fiber/city/ky/lexington).

⁴ [Spectrum \(cable & streaming hybrid\) \\$45-\\$175 per month \[https://www.spectrum.com/locations/tv-streaming-service/lexington-ky-t172\]](https://www.spectrum.com/locations/tv-streaming-service/lexington-ky-t172); [DirecTV \(satellite\) \\$89.99-\\$169.99 per month \[https://www.directvplans.com/packages\]](https://www.directvplans.com/packages); [DISH Network \(satellite\) \\$89.99-\\$119.99 per month \[https://www.dish.com/availability/ky/lexington\]](https://www.dish.com/availability/ky/lexington).

⁵ [Verizon \\$65-\\$90 per month \[https://www.verizon.com/plans/unlimited/\]](https://www.verizon.com/plans/unlimited/); [AT&T \\$50-\\$90 per month \[https://www.att.com/plans/wireless/\]](https://www.att.com/plans/wireless/); [T-Mobile \\$55-\\$90 per month \[https://www.t-mobile.com/cell-phone-plans\]](https://www.t-mobile.com/cell-phone-plans).

1 **Q: Do gas utility bills stand out as an exception to the remainder of the non-**
2 **fixed monthly expenses?**

3 A: Yes. The utility costs, as I described earlier in my testimony, are
4 predominantly fixed costs, the only variable component is the natural gas
5 commodity itself. This is analogous to a number of items above. Most
6 notably, car payments or lease payments provide access to a vehicle but in
7 order to drive it, one must still pay the variable fuel cost. This is virtually
8 identical to the fixed and variable components of the utility system,
9 whereby the fixed costs provide customers access to a reliable utility system
10 capable of delivering natural gas reliably upon demand from any customer,
11 and the variable cost covers the fuel needed when a customer desires to use
12 the system. However, the Company's current rate design does not
13 recognize this fact and places fixed cost recovery in a variable use charge.
14 The remainder of the items listed as non-fixed costs are still known costs
15 but are completely discretionary in terms of the magnitude of the expense.
16 A key difference for these items when compared to utility bills relates to the
17 utility's obligation to serve and the fixed expense incurred associated with
18 that obligation.

19 **Q: Please expand on why higher customer charges would benefit low-**
20 **income customers.**

1 A: There is a common misconception that low-income customers are low-
2 usage customers. This is not a correct characterization of low-income
3 customers who have similar average annual usage profiles as the non-low-
4 income residential customers. As the data analysis previously discussed
5 shows, the 2025 average use for a LI customer is 63.9 Mcf/year. This is 3%
6 lower than the 2025 average GR customer use of 65.7 Mcf/year.

7 Also, all else equal, higher customer charges necessitate lower
8 variable charges. The collection of costs through fixed or volumetric charges
9 is the only means of collecting the revenue to cover costs for a specific
10 customer class. The amount of total revenue target for the class does not
11 change, just which component is designed to recover what portion of the
12 total revenue target. Higher usage customers pay more when more fixed
13 customer costs are embedded in the volumetric rates. This creates an intra-
14 class subsidy transfer concern, as customers who can afford to reduce their
15 usage through energy efficiency investments can decrease their bills by
16 making such investments, while those customers who cannot afford to
17 make energy efficiency investments will see increases in their bills.

18 Further, recovering fixed costs in volumetric charges places
19 regressive burdens on low-income households who have to make decisions
20 to reduce their gas usage that impacts their quality of life. Recovering fixed

1 costs in volumetric charges increases the burden on some vulnerable
2 households during the coldest months, forcing some households to make
3 tough decisions. These households might choose between gas use for basic
4 human needs, such as heat, hot water and cooking or other choices that add
5 value to their lives (i.e., food, medical care, clothing).

6 Columbia offers a suite of targeted low-income programs, including
7 Low-Income Home Energy Assistance Program (“LIHEAP”), Energy
8 Assistance Program (“EAP”), and donation based WinterCare.⁶ There is no
9 reason to send the wrong price signal to all customers when the impacts on
10 low-income customers are mixed (i.e., their ability to respond to higher
11 variable charges, the lower quality of living they may choose to respond to
12 higher variable charges, and the fact that low-income customers that with
13 higher than average usage will disproportionately be impacted by higher
14 variable charges) and when there are programs in place that offer assistance
15 for low-income customers.

16 **Q: Please expand on the social inequity and regressive nature of recovering**
17 **fixed costs in a volumetric charge.**

⁶ [Income-Eligible Assistance Programs - Columbia Gas of Kentucky](https://www.columbiagasky.com/bills-and-payments/financial-support/income-eligible-assistance-programs)
[https://www.columbiagasky.com/bills-and-payments/financial-support/income-eligible-assistance-programs]

1 A: When certain aspects that drive how and when a customer uses energy are
2 more rigid, it limits how those customers can shift and/or reduce energy
3 consumption - such as a rental tenant not being able to alter the appliances
4 or weatherize/improve insulation in a dwelling. In this case, the tenant has
5 no choice but to accept the inefficiencies of the rental. Also, the number and
6 nature of household members impacts flexibility that could limit the ability
7 of customers to respond to volumetric rates. It is also important to note that
8 low-income households tend to choose to respond to volumetric prices by
9 reducing their energy load to save money, at times when energy is most
10 important to their standard of living. In July 2024, JPMorgan Chase released
11 a research paper that analyzed how households manage their electricity
12 bills and other spending when faced with hot weather. The primary finding
13 is that “low-income households primarily manage high electricity bills in
14 hot months by using less air conditioning and enduring more heat (and) the
15 health costs of under-cooling likely exceed the amount households save on
16 their electricity bills.”⁷ The same logic and implications apply to low-
17 income households faced with volumetric charges for gas distribution
18 service during periods of cold weather. The report also reiterates the points

⁷ JPMorgan Chase & Co. (July 18, 2024). How households manage high air conditioning bills. Retrieved from <https://www.jpmorganchase.com/institute/all-topics/financial-health-wealthcreation/how-households-manage-high-air-conditioning-bills>

1 made earlier that low-income homeowners may find it difficult to make
2 energy efficiency and weatherization investments because of the high
3 upfront costs, and “low-income renters are very unlikely to make these
4 investments because the value of the capital investment will accrue to the
5 landlord.” This usage relationship is evidenced in an article by the U.S.
6 Department of Energy that outlines high consumption as a key factor to the
7 energy burden placed on low-income households.⁸ In short, recovering
8 fixed costs in a volumetric charge places an undue burden on low-income
9 customers, who use more than average energy and choose to respond in
10 ways that reduce their standard of living, resulting in social inequities and
11 regressive outcomes with no benefit to other ratepayers, society, or the
12 Company.

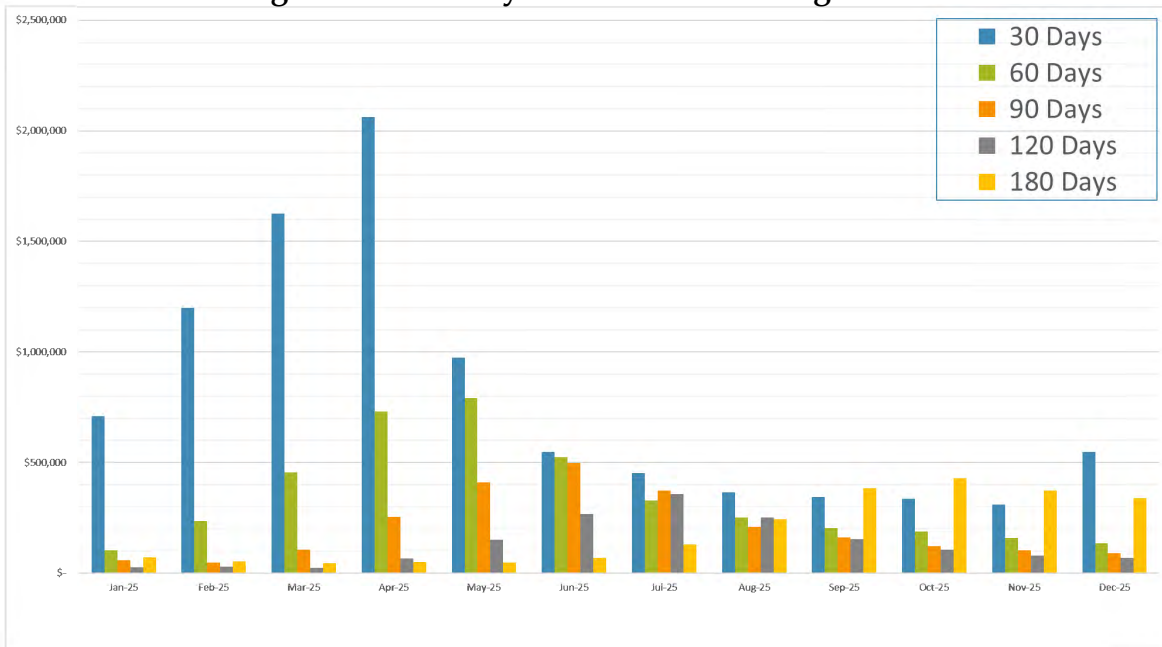
13 **Q: What does the Company’s arrearage data show about when customers**
14 **struggle most to pay their bills?**

15 A: Figure 6 below provides the monthly residential arrears data for the
16 Company and demonstrates a clear seasonal pattern; arrears increase
17 materially during the winter heating season. As customer usage rises in
18 response to cold weather, so do bills, and a growing portion of customers

⁸ See “Low-Income Household Energy Burden Varies Among States — Efficiency Can Help In All of Them” by U.S DOE https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf

1 fall behind on payments. This demonstrates that affordability challenges
2 are most acute precisely when heating demand is highest and least
3 discretionary.

4 **Figure 6 – Monthly Residential Arrearage Data**



5

6 **Q: How does the current volumetric rate design contribute to this outcome?**

7 **A:** The current rate design recovers a significant portion of fixed distribution
8 costs through volumetric charges, which causes customer bills to increase
9 sharply during the winter months. Because these costs are embedded in
10 usage-based rates, customers pay more at the exact time when they have
11 the least ability to reduce consumption. This concentrates cost recovery into
12 periods of peak financial stress and contributes directly to the observed
13 increase in arrearages.

14 **Q: Does this support the notion that volumetric pricing sends an effective**

1 **price signal?**

2 A: No. For many customers, particularly low-income households, winter
3 energy usage is largely inelastic. As discussed in my testimony, these
4 customers often lack the ability to materially reduce usage due to housing
5 constraints, household needs, or lack of access to efficiency improvements.
6 Instead of responding to higher prices through meaningful reductions in
7 consumption, many customers respond by falling behind on their bills. This
8 indicates that the price signal is not functioning as intended.

9 **Q: What is the most concerning outcome associated with this dynamic?**

10 A: The most concerning outcome is that the so-called “price signal” can lead
11 to reductions in essential energy usage that come at the expense of health
12 and quality of life, such as under-heating a home, while still leaving
13 customers with elevated bills and increasing arrearages. In other words,
14 vulnerable households may both consume less than what is needed for a
15 reasonable standard of living and still be unable to keep up with their bills
16 due to the structure of volumetric cost recovery. This reinforces the
17 regressive nature of the current design and aligns with the broader
18 evidence that recovering fixed costs through volumetric charges places
19 disproportionate burdens on low-income customers.

20 **Q: What does this imply for appropriate rate design?**

1 A: It implies that recovering a greater portion of fixed distribution costs
2 through fixed charges would better align rates with cost causation and
3 reduce the seasonal bill spikes that drive arrearages. Doing so would
4 moderate winter bill volatility, reduce financial stress on vulnerable
5 customers, and avoid the unintended and inequitable outcomes associated
6 with reliance on volumetric recovery.

7 **Q: Have other jurisdictions recently recognized the impact of recovering**
8 **fixed costs through volumetric charges on low-income customers?**

9 A: Yes. Most recently, in its order in the Docket Cause No. 45990 issued on
10 February 3, 2025, the Indiana Utility Regulatory Commission recognized
11 the following:

12 (...) we are persuaded by witness Taylor’s evidence
13 that frequently low-income customers are harmed by
14 recovery of fixed costs through a volumetric charge.
15 We are further persuaded that the TDSIC
16 [Transmission, Distribution, and Storage System
17 Improvement Charges] distribution costs should
18 continue to be recovered through a fixed charge. These
19 are fixed costs, and recovery through a volumetric
20 charge would send inefficient price signals and would
21 work to the detriment of those low-income customers
22 who are higher volume users. [Section xi.6,
23 Commission Discussion and Findings, page 113].

24 **Q: Has the Company prepared a detailed comparison of the Company’s**
25 **present and proposed rates and resulting revenues by rate class?**

26 A: Yes. This is discussed and provided in the next section of testimony.

1 VII. TYPICAL BILL COMPARISON

2 Q: How was the Schedule N, Typical Bill Comparison, developed?

3 A: Monthly usage levels were selected to provide a representative impact on a
4 typical monthly bill based on the proposed changes in rates. Tariff sales rate
5 schedules were compared with and without gas costs. Proposed changes in
6 monthly customer and volumetric charges were compared for
7 transportation rate schedules.

8 Q: Does this complete your Prepared Direct Testimony?

9 A: Yes.

Attachment RJA-1

Ronald J. Amen

CHAIRMAN & EVP

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy, and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time-of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation, and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

University of Nebraska,
Bachelor of Science with
Distinction, Business
Administration, Finance and
Economics

YEARS EXPERIENCE

45

PROFESSIONAL ASSOCIATIONS

American Gas Association
Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis, Litigation
Support, Regulatory Support,
Strategy, Utility operations



EXPERIENCE AND SELECTED ACCOMPLISHMENTS

REGULATORY POLICY, STRATEGY AND ANALYSIS

FortisBC Energy, Inc. (2016 – 2018, 2021-2022)

Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC. Retained in 2021 to update quantitative analysis of the operation of the transportation balancing rules for reporting requirements of the BCUC in 2022.

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canada Energy Regulator (CER), Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system. The case resulted in a settlement with all parties.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)

Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms were assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).



McDowell, Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery, and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009 -2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

RESOURCE PLANNING, STRATEGY AND FINANCIAL ANALYSIS

Manitoba Hydro (2024-2025)

Retained by the client to provide a financial benchmarking framework that will ensure its financial health, its ability to achieve long-term financial targets, and will support organizational decision making. Reviewed regulatory jurisdictions in Canada and the U.S. with similarly situated provincially or publicly owned electric utilities to gain an understanding of how each regulatory jurisdiction uses financial metrics in rate setting, i.e., which metrics are relied upon and how do those metrics factor into the determination of authorized rates. Review included at least one Crown or municipal utility in each Canadian province, U.S. public power hydroelectric utilities, and opportunistically brought in relevant research from other sectors. Short-listed a group of financial metrics used to assess financial health for modeling to test financial outcomes of metrics and targets for consideration by Executive Team (in progress).

Confidential Multi-Jurisdiction Gas Utility (2021-2022)

Retained by the multi-jurisdiction interstate transmission pipeline and local distribution utility ("client") to assist it in identifying and supporting a natural gas supply solution to satisfy additional deliverability requirements with the goals of minimizing costs, enhancing system resiliency, and introducing renewable fuels into its system. Reviewed the process and analyses that had been conducted to-date (including all underlying assumptions) and provided insight into the best path forward. The goal of the effort was to help prepare client for internal approval of the process and recommended path forward, and ultimately the development and approval of the necessary regulatory filings at the federal, state, and local levels. Atrium evaluated a broad spectrum of regulatory, economic, market-related, and logistical considerations in order to advise the client on the best path forward in utilizing LNG to meet its future deliverability requirements. Specific components of Atrium's analysis included regulatory approvability, rate design and cost recovery risk, site location (including siting LNG in multiple locations in multiple states), ownership structure, and ability to incorporate RNG and hydrogen into Utility's system to decarbonize the pipeline system.



Great Plains Natural Gas (2021-2022)

Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021-2022)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.



Puget Sound Energy (2002 – 2003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

COST ALLOCATION, PRICING ISSUES AND RATE DESIGN

Philadelphia Gas Works PGW (2023, 2024-2025)

Mr. Amen led an Atrium team engaged by PGW to review the mechanics, input data, billing controls, and weather trends surrounding PGW's Weather Normalization Adjustment ("WNA") formula to understand the factors that contributed to the abnormally high WNA charges in June 2022. Atrium's review identified structural factors inherent in PGW's WNA mechanism that may have contributed to the anomalous WNA amounts billed to customers in June 2022. Mr. Amen filed testimony with Atrium's findings and recommendation in the pending general rate case before the Pennsylvania Public Utility Commission. Mr. Amen provided expert testimony in PGW's 2024 general rate proceeding supporting the continuation of the WNA, supplemented by the addition of a Revenue Normalization Adjustment ("RNA") mechanism. (Case pending)

Public Service Company of Colorado (Xcel) (2024)

Mr. Amen was engaged to provide expert testimony presenting and supporting the Company's proposed Revenue Stability Mechanism ("RSM"). The RSM is a total revenue decoupling mechanism intended to separate the Company's revenue from the volume of gas it sells to help support Colorado's state decarbonization goals. The Colorado Senate Bill 21-264 directed gas utilities to submit "Clean Heat Plans" to reduce carbon dioxide and methane emissions toward Clean Heat targets in specific years. Potential emissions reduction measures include energy efficiency, biomethane, hydrogen, recovered methane, beneficial electrification of customer end users, and leak detection, among others.



Potomac Electric Power Company (PEPCO) (2022-2023)

Mr. Amen led an Atrium team engaged by PEPCO on behalf of services requested by the Public Service Commission of the District of Columbia (“DC Commission”), for comprehensive evaluation of the processes, procedures, mechanics, and internal controls surrounding PEPCO’s Bill Stabilization Adjustment (“BSA”). Atrium provided independent audit services sought by the DC Commission, including a) independently evaluate the timing, impact and magnitude of the billing determinant error that was identified during Formal Case No. 1156; b) independently confirm that current BSA processes and procedures are properly and timely executed as designed; c) independently confirm that current Pepco BSA internal controls are properly and timely executed; d) independently identify any recommended process and procedural improvements, as well as any recommended changes in existing internal controls or new internal controls; and e) independently conduct a comprehensive review of Pepco’s BSA deferral balances by customer class, with an overall determination of the breakdown of BSA deferral balances by key drivers for each customer class. Our audit report and recommendations were filed with the DC Commission in July 2023.

Summit Natural Gas of Maine, Inc. (2022 - 2023)

Mr. Amen provided revenue requirement, allocated cost of service, class revenue apportionment, rate design, and expert witness testimony support for the utility’s gas general rate case and multi-year rate plan before the Maine Public Utilities Commission. Responsibilities included determination of an optimal normal weather period for purposes of normalizing test year billing determinants, followed by the weather normalization process of determining a representative level of gas throughput for the Company’s test year. The case resulted in an all-party settlement before the Maine PUC.

Black Hills Energy Arkansas (2021-2022, 2023-2024)

Mr. Amen provided allocated cost of service, class revenue apportionment, rate design for natural gas infrastructure mechanisms, and expert witness support for two of the utility’s gas general rate case before the Arkansas Public Service Commission. The cases resulted in settlements before the Arkansas PSC.

Until Electric System, Northern Utilities, Fitchburg Gas & Electric (2021-2022, 2023-2024)

Mr. Amen provided allocated cost of service (“ACOSS”), marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility’s separate electric and gas general rate cases before the New Hampshire Public Utilities Commission, including expert witness testimony. The cases resulted in settlements before the NHPUC.



For Until affiliate, Fitchburg Gas & Electric, Mr. Amen conducted an ACOSS to determine the embedded costs of serving the Company's gas distribution customers and support its rate design efforts in its base distribution rate proceeding before the Massachusetts Department of Public Utilities. Sponsored expert witness support for the ACOSS, class revenue apportionment, proposed rate design, and bill impacts. Also sponsored the weather normalization and annualization of its billing determinants and a Marginal Cost of Service Study.

Manitoba Hydro – Centra Gas Manitoba (2021-2022)

Retained to provide an independent review of the cost of service methodologies employed for Centra Gas Manitoba Inc.'s natural gas operations. Atrium prepared a report filed with the Manitoba Public Utility Board documenting and supporting our assessment of Centra's existing COSS methods in conformance with the regulatory requirements of the MPUB. Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. Centra's 2022 rate application based on the recommendations in our report was approved by the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021, 2022 – 2023, 2024-2025)

Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission (MPSC) and North Dakota Public Service Commission (NDPSC). Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. SFV rate design was approved by the North Dakota PSC. The cases resulted in settlements approved by the respective Commissions.

Mr. Amen also represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Mr. Amen supported MDU electric general rate case filings in Montana and North Dakota (2022), including a marginal cost study in Montana, and allocated cost studies, revenue apportionment and rate design in both jurisdictions.



Mr. Amen supported gas general rate case filings in MDU’s Idaho affiliate, Intermountain Gas (2022-2023, 2025) and Washington affiliate, Cascade Natural Gas (2024). Testimony support included a class level, design day load studies across the two utilities’ temperature zones, using a combination of AMI penetration and monthly billing data, class allocated cost of service study, class revenue apportionment, and rate design.

Mr. Amen supported gas and electric general rate case filings in MDU’s South Dakota service territory (2023), including gas and electric allocated cost studies, revenue apportionment and rate design.

Mr. Amen supported MDU gas cases in Montana and Wyoming (2024), and is currently supporting MDU electric cases in Montana and Wyoming filed in 2025.

Chesapeake Utilities Corporation (2020 – 2021, 2024-2025)

Reviewed and evaluated Chesapeake’s Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Mr. Amen is currently providing testimony support for Chesapeake Utility’s Delaware general rate case (filed August 2024), including a Lead Lag study supporting cash working capital, determination of normal weather, cost of service and rate design principles, allocated cost of service results, revenue apportionment, and a modified version of a prior weather normalization adjustment (WNA) rider (Settlement pending).

NW Natural (2018 – 2019)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility’s general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)

Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake’s residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)

Engaged by LG&E and KU to conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client’s five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment (“WNA”) proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility’s general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility’s commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility’s Gas Reliability Investment Program (GRIP).



Tacoma Power (2016 – 2018, 2023, 2024 - 2025)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently providing cost of service and rate design for the 2023 – 2024 rate filing. Ongoing work involves innovative rate programs and demand forecasting.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities.
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions.
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:
 - Application Fees
 - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma related to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model, and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discussed accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design, and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017, 2021)

Conducted class allocated cost of service studies for the client’s natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company’s commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a “Straight-Fixed Variable” form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates, and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership (“EGNB”) general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB’s distribution pipeline infrastructure in New Brunswick. CA.



Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included:

1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers, and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr. Amen sponsored expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement in the 2020 general rate case.



UTILITY SYSTEM OPERATIONS AND ORGANIZATIONAL DEVELOPMENT

Philadelphia Gas Works (2017, 2020, 2024)

Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.



Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as “best practices,” from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company’s gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client’s A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client’s natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client’s utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.



EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Idaho Public Utilities Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Kentucky Public Service Commission
- Maine Public Utilities Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- South Dakota Public Utilities Commission
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission
- Federal Energy Regulatory Commission



SELECTED PUBLICATIONS / PRESENTATIONS

- “Enhancing the Profitability of Growth,” American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004
- “Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition,” Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005
- “Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes,” Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005
- “Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets,” Southern Gas Association, July 18 - 20, 2005
- “Resource Planning as a Cost Recovery Tool,” Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007
- “Natural Gas Infrastructure Development and Regulatory Challenges,” Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007
- “Resource Planning in a Changing Regulatory Environment,” Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008
- “Natural Gas Distribution Infrastructure Replacement,” American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010
- “Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders,” SNL Webinar, March 27, 2014
- “Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment,” Large Public Power Council, Rates Committee Meeting, August 14, 2014
- “Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation,” EUCI, January 22-23, 2020

Attachment RJA-2

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

Case No. 2026-00099

COLUMBIA GAS OF KENTUCKY, INC.

ATTACHMENT RJA-2

COST OF SERVICE ALLOCATION STUDY

TEST YEAR

ENDED DECEMBER 31, 2027

WITNESS: RONALD J. AMEN



Cost of Service Allocation Study

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I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Cost of Service Study (“COSS”) model and related schedules prepared for Columbia Gas of Kentucky, Inc. (“CKY” or the “Company”) based on the Test Year ended December 31, 2027 (“Test Year”).

The document is organized into three sections. The first section includes an overview of Atrium’s COSS model used to develop the cost allocation study. The second section includes details of the methodologies adopted in the development of the study. The last section exhibits the results of the COSS study.

1. Purpose of Cost Allocation

The purpose of a COSS is to determine the cost-of-service responsibilities of each customer class upon which the base rates may be established. The revenue requirement studies provide the overall level of costs of providing service, while the COSS is used to change the basic rate structures and/or the relative overall cost responsibility of each customer class. Based on the functionalization and classification of costs and allocation methodologies used in the COSS, the revenue requirement by customer class is determined and used in designing the Company’s proposed base rates. In other words, the COSS measures each class’s contribution to the Company’s overall cost of service. Comparing the costs to serve any customer class with that class’s rate revenues provides a measure of the return realized from that class and their associated revenue-to-cost ratio. This allows for a comparison across classes to ascertain the presence and extent of interclass subsidization (i.e., when one class pays more than its cost to serve, and another pays less than its cost to serve).

2. COSS Procedures

Cost of service studies utilize a three-step process: functionalization, classification, and allocation.

In the first step, the functionalization sets off with assigning the Federal Energy Regulatory Commission (“FERC”) plant accounts and associated investment balances to appropriate cost of service functions, such as Storage, Transmission, Distribution, On-Site and Metering, Customer Accounts and Service, and Gas Supply. The expenses related to particular property investments or groups of investments can often follow the same functionalization and are allocated based on the ratios of gas plant assigned to each function. These plant ratios can be used to functionalize most other cost items.

In the second step, classification, each functional cost category is further separated by cost causation. There are three basic cost-defining characteristics of natural gas services: demand, commodity, and customer.



Cost of Service Allocation Study

- Demand (Capacity) related costs are associated with the peak usage of the utility system. These costs are necessary to maintain the system at a level sufficient to satisfy the greatest demand that all the customers could place upon the system.
- Commodity-related costs are variable costs that vary with the quantity of gas consumed. These costs reflect the number of units consumed or supplied during a period of time.
- Customer-related costs are associated with serving customers regardless of their usage or demand characteristics. Customer-related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

The last step is to allocate these cost components among customer classes. The development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation.

3. Atrium Economics Cost of Service Study Model Overview

The Cost of Service Study is submitted in support of the direct testimony of Ronald J. Amen in Columbia Exhibit Tab 23. The COSS model presented in this proceeding is an excel based model that allows the user to modify various inputs and assumptions.

COSS Model Capabilities

The Atrium Economics' COSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e., production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of costs of gas, income taxes, working capital, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.



Cost of Service Allocation Study

- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Traditional 3-Step Analysis Process

The Atrium COSS Model follows the standard three-step analysis process:1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium COSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each customer class; and calculates unit costs by function for customer, commodity, and demand categories. Accounting costs are reported by FERC account level, and the allocation of A&G expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The COSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per therm, per dekatherm of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary, the COSS model outputs can be easily modified to meet specific jurisdictional filing requirements.



II. CKY'S COST OF SERVICE PROCEDURES

1. Functionalization

The following functional cost categories were identified for purposes of CKY's cost allocation:

- Distribution
- Gas Costs
- Onsite & Metering
- Customer Accounts and Services

CKY's assigned functional categories are presented on Schedule 1 – Account Balances and Allocation Methods.

2. Classification

The following classification categories were identified for purposes of CKY's cost allocation:

- Demand
- Commodity
- Customer

CKY's assigned classification categories are presented on Schedule 1 – Account Balances and Allocation Methods.

3. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External (Schedule 2) and Internal (Schedule 3) Allocation Factors are utilized to allocate costs among various customer classes. CKY's assigned Allocation Factors are presented on Schedule 1 – Account Balances and Allocation Methods.

3.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

- General Service – Residential (GS – Residential)
- General Service – Other (GS – Other)
- Intrastate Utility Service (IUS)
- Main Line Delivery Service (incl. Special Contracts) (DS-ML)
- Interruptible Delivery Service (DS-IS)



Cost of Service Allocation Study

3.2. External Allocation Factors

CKY’s External Allocation Factors are presented on Schedule 2. The External Allocation Factors are developed based on the special studies conducted using various detailed data as discussed below.

Commodity and Revenue Allocation Factors

Costs classified as “Commodity” are allocated among customer classes based on the weather-normalized volumes for the test year.

Allocation Factor	Description
TOTAL REVENUE	Factor developed to directly assign total Sales and Transportation revenue to the specific class in the Test Year.
REVENUE GAS SERVICE	Factor developed to directly assign total Sales and Transportation Margin Revenue to the specific class in the Test Year.
REVENUE TRANSPORT	Factor developed to directly assign Transportation Revenue to the specific class in the Test Year.
GAS COST	Factor developed to directly assign Gas Purchasing Expense excluding DS-ML.
NON-GAS COST REVENUE SALES	Factor developed to directly assign current Margin Revenue (Total Sales Revenue less Gas Cost Revenue).
TRACKERS	Factor developed to assign Tracker Revenue to the specific class in the Test Year.
THROUGHPUT	Factor developed to directly assign Weather Normalized Volumes/Throughput to the specific class in the Test Year.
THROUGHPUT EXCL DS-ML	Factor developed to directly assign Weather Normalized Volumes/Throughput excluding Main Line Delivery Service.

Customer Allocation Factors

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

Allocation Factor	Description
CUSTOMERS	Customer Count factor is based on the average number of customers per customer class in the Test Year.



Cost of Service Allocation Study

Allocation Factor	Description
CUSTOMER EXCL DS-ML	Customer Count factor is based on the average number of customers per customer class excluding DS-ML
METERS ACCT 381	<p>Meters Account 381 based on identification of meters by Rate Schedule excluding DS-ML.</p> <p>Meter Allocation factor is based on the identification of meters by rate class and by size of meter in Columbia’s Distributive Information System (“DIS”), customer billing system and the average unit cost for each size of meter, as maintained in Columbia’s books and records. From DIS, individually installed meters were summarized by rate schedule and by size as of December 31, 2025. The average cost for each size meter, as determined from Columbia’s Plant Account Records, was applied to the number of meters for each rate class.</p>
IND M&R ACCT 385	<p>The factor was derived to allocation FERC Account 385 Industrial M&R Station Equipment. The allocation of this plant account was based on individual measuring stations by station number and customer account excluding DS-ML.</p>
SERVICES ACCT 380	<p>Services Account 380 as assigned by Rate Schedule excluding DS-ML. The analysis relies on number of service lines under three inches and those service lines greater than three inches. Columbia’s books and records maintain its service investment by size and kind. Based on per book data as of December 31, 2025, services were grouped by sizes under three inches and over three inches. An average unit cost was calculated for service lines under three inches and applied to the number of service lines under three inches by rate class. Likewise, the same calculation was performed for service lines three inches or more by size, by rate class. Service lines for DS-ML were directly assigned.</p>
UNCOLLECTIBLES	<p>This factor is based on the Bad Debt write-offs for twelve months ending December 31, 2025.</p>
DS-ML DIRECT	<p>This factor directly assigns costs to Mainline customers.</p>

Demand Allocation Factors

Demand-related costs are generally allocated based on peak capacity demand for each customer class.



Cost of Service Allocation Study

Allocation Factor	Description
DESIGN DAY	The factor is based on Design Day Peak Demand for each customer class.
DESIGN DAY EXCL DS-ML	This factor is based on Design Day Peak Demand excluding Main Line Delivery Service class.
DESIGN DAY EXCL INTERR DEMAND	This factor is based on Design Day Peak Demand excluding Interruptible Demand customers.
PEAK AVERAGE	The composite factor is based on the DESIGN DAY EXCL DS-ML and THROUGHPUT EXCL DS-ML prorated to the commodity and demand components determined in the Mains Peak and Average Analysis.
AVG DESIGN DAY P&A DEMAND	The composite factor is based on the DESIGN DAY EXCL DS-ML and THROUGHPUT EXCL DS-ML prorated to the commodity and demand components determined in the Mains Average Study Analysis.

3.3. Mains Analysis

The allocation of investment in facilities serving a distribution function should recognize that the cost of these facilities is driven by two principal factors. First is the cost of extending the system to connect individual customers. Second is the cost associated with the capacity requirements of the customers connected.

There are two widely accepted methods for the classification of mains between customer-related costs and demand-related costs. The two methods are the Minimum System Method and the Zero-Intercept Method, both relying on the Company’s property record data to determine the cost of pipe by size and type. Diameter groups that did not contain enough sample data were removed. The unit cost for pipe in any year is determined by dividing the booked costs by the amount of pipe installed in a standard unit of measurement. A variety of factors, such as the length of pipe installed, location, installation conditions, etc., cause the annual unit cost of pipe by size and type to vary significantly. Thus, a simple average of the yearly costs is not adequate for a determination of the cost for each size of the pipe as it will not reflect a consistent set of data. Therefore, the original cost data was restated in terms of current cost using the Handy-Whitman index.



Cost of Service Allocation Study

Zero-Intercept Study:

The zero-intercept study was performed using a Weighted Linear Regression (WLR) on the cost per foot by pipe diameter. Based on this relationship, the study estimates the cost of installing a hypothetical pipe with zero capacity, which is where the estimated diameter is zero (i.e., the zero-intercept). The zero-intercept determined value is then multiplied by all quantities of distribution mains currently installed by the utility to arrive at a total minimum system cost. Total minimum system cost divided by total system cost derives the portion of the system that is considered a fixed investment and is classified as customer-related.

Zero-Intercept		Zero-Intercept Unit		Customer	
Plastic - Weighted Linear Regression		Cost	Component (\$)	Component (%)	Customer Component (%)
Steel - Weighted Linear Regression		Cost	Component (\$)	Component (%)	Customer Component (%)
Material	Footage	Cost 2025	Cost	Component (\$)	Customer Component (%)
Plastic	8,380,372	\$ 566,879,215	\$ 38.10	\$ 319,282,434	56%
Steel	5,822,237	\$ 948,666,021	\$ 68.59	\$ 399,340,468	42%
Total	14,202,609	\$ 1,515,545,237	\$	718,622,902	47.42%

The distribution main investment is functionalized to distribution, classified based on the results of the zero-intercept study to demand (47.4%) and customer (52.6%). The demand component of the mains investment is allocated based on each class’s allocation of peak day. The customer component of the mains investment is allocated based on each class’s number of customers.

Cost of Service Study Methods

In addition to the zero-intercept study discussed above, for comparison purposes two other mains studies were conducted: the Customer/Demand Study and the Demand/Commodity Study.

Customer/Demand Method

Under the Customer/Demand Method, the demand component is the portion remaining after the customer component is determined using the zero-intercept methodology. The demand component of mains was allocated to the various classes based on design day throughput (i.e., gas sales and transportation) under each method.

Demand/Commodity

The demand-related investment was allocated to the customer classes based on their respective contribution to peak day demand under system design weather conditions or Design Day basis. The commodity component was allocated to the customer classes based on their respective annual throughput. Under the Demand/Commodity Method, the demand and



Cost of Service Allocation Study

commodity components were each considered equal in weight regarding mains. Therefore, the demand component was used to allocate 50% of the cost of mains.

Average Study:

A Composite Allocation factor which is the Average of the Customer/Demand and Demand/Commodity allocation factors. The Average study is the basis for Company’s revenue apportionment.

3.4. Internal Allocation Factors

Internal Allocation Factors are developed within the COSS model based on the cost ratios of allocated cost based the external allocation factors, representing various forms of the composite external and internal factors as mathematical sums.

Allocation Factor	Description
INT_RATEBASE	Rate Base. This factor is based on the results of the allocated balance of rate base.
INT_TOTAL PLANT	Total Plant. This factor was based on allocated amounts of total plant by customer class.
INT_MAINS_PLANT	Mains. This factor was based on the allocation of Mains account 376 utilizing external allocation factors.
INT_MAINS_SERVICES	Mains and Services. This factor was based on the allocation of Mains account 376 and Services account 380 utilizing external allocation factors.
INT_DISTPT_SUBTOTAL	Distribution Plant. This factor is based on allocated distribution plant, excluding accounts 375.7, 375.71 and 387.
INT_IND M&R	Industrial M&R Station Equipment. This factor is based on the allocation of M&R Station Equipment in account 385.
INT_871-879	Operation Expense. This factor is based on the allocation of operation expenses included in accounts 871 - 879.
INT_866-893	Maintenance Expense. This factor is based on the allocation of maintenance expenses included in accounts 866 – 893.
INT_OM_EXC_A&G, GAS, UNCOLL	O&M Expense excluding A&G, Gas Supply and Uncollectible expenses. This factor is based on total allocated O&M expense excluding A&G, Gas and Uncollectible expenses.



Cost of Service Allocation Study

Allocation Factor	Description
INT_REVENUE REQUIREMENT	Revenue Requirement. This factor is based on the results of the allocated total revenue requirement at equal rates of return.



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1	RATE BASE								
2	Plant in Service								
3	Intangible Plant								
4	Organization	301.0	521	INT_DISTPT_SUBTOTAL					
5	Misc. Intangible Plant - Plant Related	303.0	67,763	INT_DISTPT_SUBTOTAL					
6	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	18,003,441	INT_DISTPT_SUBTOTAL					
7	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	10,172,694	INT_DISTPT_SUBTOTAL					
8	Subtotal - Intangible Plant		28,244,419						
9	Distribution Plant								
10	LAND-CITY GATE & MAIN LINE IND. M & R	374.1	865,478		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
11	LAND-OTHER DISTRIBUTION SYSTEMS	374.2	3,989,298		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
12	RIGHTS OF WAY	374.5	2,692,649		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
13	STRUCTURES & IMPROVEMENTS	375.0	3,638,927		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
14	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.4	46,211		DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT		DS-ML_DIRECT
15	STRUC & IMPROV-DISTR. IND. M & R	375.6	0		ON SITE	CUSTOMER			IND_M&R_ACCT 385
16	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.7	9,466,014	INT_DISTPT_SUBTOTAL					
17	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	707,588	INT_DISTPT_SUBTOTAL					
18	STRUC & IMPROV-COMMUNICATIONS	375.8	132,125		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
19	MAINS (Less SMRP)	376.0	503,400,503		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
20	MAINS - DS-ML DIRECT ASSIGNMENT	376.0	0		DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT		DS-ML_DIRECT
21	M & R STATION EQUIP-REG (LESS SMRP)	378.0	33,227,359		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
22	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.2	186,002		DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT		DS-ML_DIRECT
23	M & R STA EQUIP REG FMV	378.2	(777,092)		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
24	M & R STA EQUIP-CITY GATE CHECK STA	379.0	1,555,048		DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND		CUSTOMERS EXCL DS-ML
25	SERVICES (Less SMRP)	380.0	251,105,625		ON SITE	CUSTOMER			SERVICES_ACCT 380
26	METERS	381.0	21,899,898		ON SITE	CUSTOMER			METERS_ACCT 381
27	METERS - AMI	381.1	8,252,969		ON SITE	CUSTOMER			METERS_ACCT 381
28	METER INSTALLATIONS (Less SMRP)	382.0	12,571,612		ON SITE	CUSTOMER			METERS_ACCT 381
29	HOUSE REGULATORS (Less SMRP)	383.0	9,748,687		ON SITE	CUSTOMER			METERS_ACCT 381
30	HOUSE REGULATOR INSTALLATIONS	384.0	(396)		ON SITE	CUSTOMER			METERS_ACCT 381
31	INDUSTRIAL M & R STATION EQUIPMENT	385.0	6,222,322		ON SITE	CUSTOMER			IND_M&R_ACCT 385
32	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385.0	919,617		ON SITE	CUSTOMER			DS-ML_DIRECT
33	OTHER EQUIPMENT	387.00	3,482,821	INT_DISTPT_SUBTOTAL					
34	Subtotal - Distribution Plant		873,333,264						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
35	General Plant								
36	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	1,602,375	INT_DISTPT_SUBTOTAL					
37	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	591,397	INT_DISTPT_SUBTOTAL					
38	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	48,924	INT_DISTPT_SUBTOTAL					
39	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	24,462	INT_DISTPT_SUBTOTAL					
40	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	7,270,103	INT_DISTPT_SUBTOTAL					
41	LABORATORY EQUIPMENT	395.0	59,420	INT_DISTPT_SUBTOTAL					
42	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	185,547	INT_DISTPT_SUBTOTAL					
43	MISCELLANEOUS EQUIPMENT	398.0	127,398	INT_DISTPT_SUBTOTAL					
44	Subtotal - General Plant		9,909,627						
45	Total Plant in Service		911,487,309						
46	Accumulated Depreciation & Amortization								
47	Intangible Plant								
48	Organization	301.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
49	Misc. Intangible Plant - Plant Related	303.0	(59,766)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
50	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	(7,366,977)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
51	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	(3,085,072)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
52	Subtotal - Intangible Plant		(10,511,815)						

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53	Distribution Plant								
54	LAND-CITY GATE & MAIN LINE IND. M & R	374.1	0	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
55	LAND-OTHER DISTRIBUTION SYSTEMS	374.2	(438,836)	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
56	RIGHTS OF WAY	374.5	(1,260,932)	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
57	STRUCTURES & IMPROVEMENTS	375.0	(715,365)	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
58	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.4	(8,012)	-	DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT	-	DS-ML_DIRECT
59	STRUC & IMPROV-DISTR. IND. M & R	375.6	0	-	ON SITE	CUSTOMER	-	-	IND_M&R_ACCT 385
60	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.7	(5,394,576)						
61	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	(705,437)						
62	STRUC & IMPROV-COMMUNICATIONS	375.80	(25,156)	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
63	MAINS (Less SMRP)	376.00	(97,006,543)	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
64	MAINS - DS-ML DIRECT ASSIGNMENT	376.00	0	-	DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT	-	DS-ML_DIRECT
65	M & R STATION EQUIP-REG (LESS SMRP)	378.00	(1,067,686)	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
66	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.20	(11,115)	-	DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT	-	DS-ML_DIRECT
67	M & R STA EQUIP REG FMV	378.21	289,236	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
68	M & R STA EQUIP-CITY GATE CHECK STA	379.00	(491,176)	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
69	SERVICES (Less SMRP)	380.00	(87,745,650)	-	ON SITE	CUSTOMER	-	-	SERVICES_ACCT 380
70	METERS	381.00	(2,614,472)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
71	METERS - AMI	381.1	(3,974,894)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
72	METER INSTALLATIONS (Less SMRP)	382.0	(5,710,480)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
73	HOUSE REGULATORS (Less SMRP)	383.0	(4,232,936)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
74	HOUSE REGULATOR INSTALLATIONS	384.0	799	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
75	INDUSTRIAL M & R STATION EQUIPMENT	385.0	(1,536,097)	-	ON SITE	CUSTOMER	-	-	IND_M&R_ACCT 385
76	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385.0	(209,137)	-	ON SITE	CUSTOMER	-	-	DS-ML_DIRECT
77	OTHER EQUIPMENT	387.0	(427,508)						
78	Subtotal - Distribution Plant		(213,285,971)						

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79	General Plant								
80	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	(545,605)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
81	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	(218,406)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
82	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	(18,294)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
83	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	(45,109)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
84	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	(2,290,578)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
85	LABORATORY EQUIPMENT	395.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
86	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	(172,402)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
87	MISCELLANEOUS EQUIPMENT	398.0	(78,542)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
88	Subtotal - General Plant		(3,368,936)						
89	Other Assets								
90	Retirement Work in Progress	N/A	4,921,119	INT_MAINS_PLANT					
91	Subtotal - Other Assets		4,921,119						
92	Total Accumulated Depreciation & Amortization		(222,245,603)						
93	Other Rate Base Items								
94	Accumulated deferred income taxes	190.0	(115,024,371)	INT_TOTAL PLANT					
95	Materials & Supplies	154.0	0	INT_DISTPT_SUBTOTAL					
96	Gas Stored Underground	164.0	35,465,643		DISTRIBUTION	DEMAND	DESIGN DAY EXCL INTERR DEMAND		
97	Total Other Rate Base Items		(79,558,728)						
98	TOTAL RATE BASE		609,682,978						

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99	OPERATION AND MAINTENANCE EXPENSE									
100	Production, Storage, LNG, Transmission, and Distribution Expense									
101	Other Gas Supply Expenses									
102	Natural gas well head purchases	801-803	77,159,140		GAS COSTS	COMMODITY		GAS_COST		
103	Natural Gas City Gate Purchases	804	3,713,241		GAS COSTS	COMMODITY		GAS_COST		
104	Other gas purchases	805	719,988		GAS COSTS	COMMODITY		GAS_COST		
105	Exchange gas	806	(969,882)		GAS COSTS	COMMODITY		GAS_COST		
106	Gas Withdrawn from Storage	808	1,221,419		GAS COSTS	COMMODITY		GAS_COST		
107	Gas Used for Other Utility Operations	812	(122,013)		GAS COSTS	COMMODITY		GAS_COST		
108	Exchange Fees	813	0		GAS COSTS	COMMODITY		GAS_COST		
109	Purchased Gas Expense	807.0	346,462		DISTRIBUTION	COMMODITY		GAS_COST		
110	Subtotal - Other Gas Supply Expenses		82,068,354							
111	Operation Expenses									
112	Transmission Expense - Operations	852	16,280	INT_MAINS_PLANT						
113	Other expenses	859	0	INT_MAINS_PLANT						
114	M&R Station Equipment	865	0	INT_MAINS_PLANT						
115	Operation supervision and engineering	870.0	1,147,127	INT_871-879						
116	Distribution load dispatching	871.0	183,031		DISTRIBUTION	CUSTOMER			THROUGHPUT EXCL DS-ML	
117	Mains and services expenses	874.0	7,644,633	INT_MAINS_SERVICES						
118	Measuring and regulating station expenses—general	875.0	357,433	INT_MAINS_PLANT						
119	Measuring and regulating station expenses—industrial	876.0	119,377	INT_IND M&R						
120	Meter and house regulator expenses	878.0	1,952,775		ON SITE	CUSTOMER			METERS_ACCT 381	
121	Customer installations expenses	879.0	3,373,937		ON SITE	CUSTOMER			METERS_ACCT 381	
122	OTHER EXPENSE	880.0	2,077,348	INT_871-879						
123	TELECOMMUNICATION EXPENSE - ENGINEERING	881.0	29,478	INT_871-879						
124	Subtotal - Operation Expenses		16,901,420							
125	Maintenance Expenses									
126	Maintenance supervision and engineering	885.0	110,855	INT_866-893						
127	Maintenance of structures and improvements	886.0	254,031	INT_MAINS_PLANT						
128	Maintenance of mains	887.0	3,449,522	INT_MAINS_PLANT						
129	Maintenance of measuring and regulating station equipment—general	889.0	665,447	INT_MAINS_PLANT						
130	Maintenance of measuring and regulating station equipment—industrial	890.0	84,976	INT_IND M&R						
131	Maintenance of services	892.0	877,715		ON SITE	CUSTOMER			SERVICES_ACCT 380	
132	Maintenance of meters and house regulators	893.0	177,057		ON SITE	CUSTOMER			METERS_ACCT 381	
133	Maintenance of other equipment	894.0	412,686	INT_866-893						
134	Subtotal - Maintenance Expenses		6,032,290							
135	Total Production, Storage, LNG, Transmission, and Distribution Expense		105,002,064							

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136	Customer Accounts, Service, and Sales Expense								
137	Customer Account								
138	Supervision	901.0	0						
139	Meter reading expenses	902.0	310,029		CUST ACCTS	CUSTOMER			CUSTOMERS
140	Customer records and collection expenses	903.0	3,127,972		CUST ACCTS	CUSTOMER			CUSTOMERS
141	Uncollectible accounts	904.0	1,252,775		CUST ACCTS	CUSTOMER			UNCOLLECTIBLES
142	Miscellaneous customer accounts expenses	905.0	30,449		CUST ACCTS	CUSTOMER			CUSTOMERS
143	Subtotal - Customer Account		4,721,225						
144	Customer Service & Information Expenses								
145	Supervision	907.0	0						
146	Customer assistance expenses	908.0	105,607		CUST ACCTS	CUSTOMER			CUSTOMERS
147	Informational and instructional advertising expenses	909.0	3,530		CUST ACCTS	CUSTOMER			CUSTOMERS
148	Miscellaneous customer service and informational expenses	910.0	298,769		CUST ACCTS	CUSTOMER			CUSTOMERS
149	Subtotal - Customer Service & Information Expenses		407,905						
150	Sales Expenses								
151	Supervision	911.0	0						
152	Demonstrating and selling expenses	912.0	1,284		CUST ACCTS	CUSTOMER			CUSTOMERS
153	Advertising expenses	913.0	0		CUST ACCTS	CUSTOMER			CUSTOMERS
154	Miscellaneous sales expenses	916.0	0						
155	Subtotal - Sales Expenses		1,284						
156	Total Customer Accounts, Service, and Sales Expense		5,130,415						
157	Administrative and General Expenses								
158	Administrative and general salaries	920.0	11,434,627	INT_OM_Exc_A&G,Gas,Uncoll					
159	Office supplies and expenses	921.0	1,177,047	INT_OM_Exc_A&G,Gas,Uncoll					
160	Outside services employed	923.0	7,781,408	INT_OM_Exc_A&G,Gas,Uncoll					
161	Property insurance	924.0	59,157	INT_OM_Exc_A&G,Gas,Uncoll					
162	Injuries and damages	925.0	1,541,664	INT_LABOR					
163	Employee pensions and benefits	926.0	5,614,427	INT_LABOR					
164	Regulatory commission expenses	928.0	1,671,790	INT_OM_Exc_A&G,Gas,Uncoll					
165	General advertising expenses	930.1	9,938	INT_OM_Exc_A&G,Gas,Uncoll					
166	Miscellaneous general expenses	930.2	(147,349)	INT_OM_Exc_A&G,Gas,Uncoll					
167	Rents	931.0	780,512	INT_OM_Exc_A&G,Gas,Uncoll					
168	Maintenance of general plant	932.0	756,318	INT_OM_Exc_A&G,Gas,Uncoll					
169	Total Administrative and General Expenses		30,679,539						
170	TOTAL OPERATION AND MAINTENANCE EXPENSE		140,812,018						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
171	Adjustments, Depreciation and Amortization Expense								
172	Depreciation Expense								
173	Intangible Plant								
174	Organization	301.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
175	Misc. Intangible Plant - Plant Related	303.0	2,259	INT_DISTPT_SUBTOTAL	-	-	-	-	-
176	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	3,257,470	INT_DISTPT_SUBTOTAL	-	-	-	-	-
177	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	2,111,058	INT_DISTPT_SUBTOTAL	-	-	-	-	-
178	Subtotal - Intangible Plant		5,370,786						
179	Distribution Plant								
180	LAND-CITY GATE & MAIN LINE IND. M & R	374.10	0	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
181	LAND-OTHER DISTRIBUTION SYSTEMS	374.20	0	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
182	RIGHTS OF WAY	374.50	43,082	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
183	STRUCTURES & IMPROVEMENTS	375.00	105,465	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
184	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.40	850	-	DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT	-	DS-ML_DIRECT
185	STRUC & IMPROV-DISTR. IND. M & R	375.60	0	-	ON SITE	CUSTOMER	-	-	IND_M&R_ACCT 385
186	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.70	284,927	INT_DISTPT_SUBTOTAL	-	-	-	-	-
187	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	25,046	INT_DISTPT_SUBTOTAL	-	-	-	-	-
188	STRUC & IMPROV-COMMUNICATIONS	375.80	3,448	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
189	MAINS (Less SMRP)	376.00	11,973,529	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
190	MAINS - DS-ML DIRECT ASSIGNMENT	376.00	0	-	DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT	-	DS-ML_DIRECT
191	M & R STATION EQUIP-REG (LESS SMRP)	378.00	1,158,744	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
192	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.20	5,022	-	DISTRIBUTION	AVGERAGE STUDY	DS-ML_DIRECT	-	DS-ML_DIRECT
193	M & R STA EQUIP REG FMV	378.21	(25,730)	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
194	M & R STA EQUIP-CITY GATE CHECK STA	379.00	47,273	-	DISTRIBUTION	AVGERAGE STUDY	AVG_DESIGN DAY_DEM-COMM_DEMAND	-	CUSTOMERS EXCL DS-ML
195	SERVICES (Less SMRP)	380.00	14,624,949	-	ON SITE	CUSTOMER	-	-	SERVICES_ACCT 380
196	METERS	381.00	907,433	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
197	METERS - AMI	381.10	584,377	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
198	METER INSTALLATIONS (Less SMRP)	382.00	363,522	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
199	HOUSE REGULATORS (Less SMRP)	383.00	273,943	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
200	HOUSE REGULATOR INSTALLATIONS	384.00	(0)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
201	INDUSTRIAL M & R STATION EQUIPMENT	385.00	384,328	-	ON SITE	CUSTOMER	-	-	IND_M&R_ACCT 385
202	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385.00	41,088	-	ON SITE	CUSTOMER	-	-	DS-ML_DIRECT
203	OTHER EQUIPMENT	387.00	188,670	INT_DISTPT_SUBTOTAL	-	-	-	-	-
204	Subtotal - Distribution Plant		30,989,966						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 1 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
205	General Plant								
206	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	88,131	INT_DISTPT_SUBTOTAL	-	-	-	-	-
207	OFFICE FURN & EQUIP-INFO SYSTEMS	391.1	121,236	INT_DISTPT_SUBTOTAL	-	-	-	-	-
208	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	685	INT_DISTPT_SUBTOTAL	-	-	-	-	-
209	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.2	342	INT_DISTPT_SUBTOTAL	-	-	-	-	-
210	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	327,312	INT_DISTPT_SUBTOTAL	-	-	-	-	-
211	LABORATORY EQUIPMENT	395.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
212	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	928	INT_DISTPT_SUBTOTAL	-	-	-	-	-
213	MISCELLANEOUS EQUIPMENT	398.0	8,733	INT_DISTPT_SUBTOTAL	-	-	-	-	-
214	Subtotal - General Plant		547,367						
215	Total - Depreciation Expense		36,908,120						
216	Total Adjustments, Depreciation and Amortization Expense		36,908,120						
217	Taxes								
218	Taxes Other Than Income Taxes								
219	Taxes Other Than Income Taxes - Property	408.1	6,228,059	INT_DISTPT_SUBTOTAL					
220	Taxes Other Than Income Taxes - Payroll	408.2	1,055,370	INT_LABOR					
221	Taxes Other Than Income Taxes - Other	408.3	228,400	INT_LABOR					
222	Subtotal - Taxes Other Than Income Taxes		7,511,829						
223	Income Taxes								
224	FEDERAL INCOME TAXES	409.1	(4,181,717)	INT_RATEBASE					
225	STATE INCOME TAXES	409.2	(1,212,778)	INT_RATEBASE					
226	DEFERRED INCOME TAX EXPENSE - FEDERAL	410-411.1	5,458,256	INT_RATEBASE					
227	DEFERRED INCOME TAX EXPENSE - FEDERAL	410-411.2	1,668,593	INT_RATEBASE					
228	Subtotal - Income Taxes		1,732,354						
229	Total Taxes		9,244,183						
230	REVENUE REQUIREMENT AT EQUAL RATES OF RETURN								
231	Test Year Expenses at Current Rates		186,964,320						
232	Return on Rate Base		49,701,356	INT_RATEBASE					
233	Gross Up Items								
234	Gross-up Federal Income Tax		7,127,176	INT_RATEBASE					
235	Gross-up State Utility Tax		1,786,258	INT_RATEBASE					
236	Gross-up Bad Debts		160,419		CUST ACCTS	CUSTOMER			UNCOLLECTIBLES
237	Gross-up Annual Filing Fee		82,727	INT_RATEBASE					
238	TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN		245,822,256						

Columbia Gas of Kentucky, Inc.
Development of External Allocators
Test Year - December 31, 2027
Attachment RJA-2, Schedule 2

Line	Allocator Code	Allocation Factor Description	Classifier	Total	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
1	CUSTOMER EXTERNAL ALLOCATORS								
2	CUSTOMERS	Average Customers	CUS	100%	90.0%	10.0%	0.0%	0.0%	0.0%
3		Test year average number of customers		139,766	125,737	13,960	2	3	64
4	CUSTOMERS EXCL DS-ML	Average Customers (excl. DS-ML)	CUS	100%	90.0%	10.0%	0.0%	0.0%	0.0%
5		Test year average number of customers excluding mainline		139,763	125,737	13,960	2		64
6	METERS_ACCT 381	Customer Meters - Acc 381 (excl. DS-ML)	CUS	100%	73.1%	25.6%	0.0%	0.0%	1.3%
7		Test year meter counts excluding mainline		29,980,405	21,901,118	7,675,505	2,678	-	401,104
8	IND_M&R_ACCT 385	INDUSTRIAL M&R - Acc 385 (excl. DS-ML)	CUS	100%	0.0%	30.1%	0.2%	0.0%	69.7%
9		Industrial measuring and regulating equipment excluding mainline		4,871,786	-	1,467,281	11,018	-	3,393,488
10	SERVICES_ACCT 380	Services - Acc 380 (excl. DS-ML)	CUS	100%	89.6%	10.3%	0.0%	0.0%	0.1%
11		Test year servcies excluding mainline		237,417,307	212,607,648	24,466,391	3,413	-	339,855
12	UNCOLLECTIBLES	Uncollectibles	CUS	100%	83.9%	15.5%	0.0%	0.0%	0.6%
13		Test year write-offs by class		1,361,351	1,141,936	210,864	-	-	8,551
14	DS-ML_DIRECT	Mainline Service Direct Assignment	CUS	100%	0.0%	0.0%	0.0%	100.0%	0.0%
				1	-	-	-	1	-
15	COMMODITY EXTERNAL ALLOCATORS								
16	TOTAL_REVENUE	Total Sales and Transportation	REV	100.0%	63.0%	31.9%	0.1%	0.4%	4.6%
17				209,333,330	131,969,426	66,736,188	108,936	912,236	9,606,545
18	REVENUE_GAS SERVICE	Total Sales and Transportation Margin Revenue	REV	100.0%	64.1%	27.5%	0.0%	0.7%	7.6%
19				126,854,075	81,373,979	34,924,325	36,991	912,236	9,606,545
20	REVENUE_TRANSPORT	Transportation Revenue	REV	100.0%	30.6%	27.1%	0.0%	0.2%	42.1%
21				24,151,996	7,391,398	6,542,677	-	57,070	10,160,850
22	GAS_COST	GAS PURCHASED COST (excluding DS-ML)	REV	100.0%	61.1%	38.8%	0.1%	0.0%	0.0%
23				81,721,892	49,914,758	31,735,361	71,774	-	-
24	NON-GAS COST_REVENUE_SALES	Margin revenue (Total Sales Revenue less gas cost revenue)	REV	100.0%	69.7%	7.1%	-0.1%	2.0%	21.3%
				45,132,183	31,459,221	3,188,965	(34,783)	912,236	9,606,545
25	TRACKERS	Tracker Revenue	REV	100.0%	89.9%	10.1%	0.0%	0.0%	0.0%
				757,362	680,690	76,502	171	-	-
26	THROUGHPUT	Weather Normalized Volumes	COM	100.0%	34.1%	25.9%	0.0%	2.2%	37.7%
27				23,704,470	8,091,498	6,142,658	10,601	519,300	8,940,413
28	THROUGHPUT EXCL DS-ML	Weather Normalized Volumes (excl. DS-ML)	COM	100.0%	34.9%	26.5%	0.0%	0.0%	38.6%
29				23,185,170	8,091,498	6,142,658	10,601		8,940,413

30 **DEMAND EXTERNAL ALLOCATORS**

31	DESIGN DAY	Peak Day (Design Day)	DEM	100.0%	41.1%	26.2%	0.0%	31.7%	1.0%
32					338,280	138,880	88,700	100	107,200
33	DESIGN DAY EXCL DS-ML	Peak Day (Design Day) excl. DS-ML	DEM	100.0%	60.1%	38.4%	0.0%	0.0%	1.5%
34					231,080	138,880	88,700	100	-
35	DESIGN DAY EXCL INTERR DEMAND	Peak Day (Design Day) excl. Interruptible Demand	DEM	100.0%	61.0%	39.0%	0.0%	0.0%	0.0%
36					227,680	138,880	88,700	100	-
37	DEMAND_COMMODITY	Design Day and Commodity Allocation Factor	DEM	100%	47.5%	32.4%	0.0%	0.0%	20.0%
38	AVG_DESIGN DAY_DEM-COMM_DEMAND	Average Study Demand Allocation Factor	DEM	100%	51.8%	34.5%	0.0%	0.0%	13.6%
39									

40 **MAINS CLASSIFICATION**

41		CUSTOMER AND DEMAND COMPONENTS OF MAINS - Zero-Int	
42		Customer Component	47.42%
43	ZERO_INTERCEPT	Demand Component	52.58%
44		Design Day and Commodity Allocation of Mains (50-50)	
45		Commodity Allocated	50.00%
46	DEMAND-COMMODITY	Demand Allocated	50.00%
47		Customer, Design Day, and Commodity Allocation of Mains under Average Study Method	
48		Customer Allocation (Customer Component)	23.71%
49		Commodity Allocated	25.00%
50		Demand Allocated	51.29%
51	AVERAGE STUDY	Total Demand Component	76.29%

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 3 - Internal Allocation Summary

Line No.	Category Description	Total System	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
1	Allocation Basis						
2	INT_MAINS_PLANT	503,400,503	306,472,543	144,374,302	170,988	-	52,382,671
3	INT_MAINS_SERVICES	754,506,128	531,338,105	170,251,305	174,598	-	52,742,120
4	INT_DISTPT_SUBTOTAL	859,676,840	597,263,551	198,558,058	208,752	1,151,829	62,494,650
5	INT_IND M&R	7,141,938	-	1,874,034	14,072	919,617	4,334,216
6	INT_871-879	13,631,187	9,556,225	3,271,040	2,685	15,371	785,865
7	INT_866-893	5,508,749	3,575,206	1,411,099	1,680	10,942	509,823
8	INT_LABOR	13,660,803	9,864,468	3,075,206	2,728	23,142	695,259
9	INT_OM_Exc_A&G,Gas,Uncoll	26,811,350	19,250,749	5,989,062	5,227	31,106	1,535,207
10	INT_TOTAL PLANT	911,487,309	633,259,060	210,524,631	221,333	1,221,247	66,261,039
11	INT_RATEBASE	609,682,978	411,826,162	151,849,330	165,273	811,525	45,030,689
12	INT_REVENUE REQUIREMENT	245,822,256	165,903,735	69,187,877	108,817	217,032	10,404,795
13	Allocation Percentage						
14	INT_MAINS_PLANT	100.0%	60.9%	28.7%	0.0%	0.0%	10.4%
15	INT_MAINS_SERVICES	100.0%	70.4%	22.6%	0.0%	0.0%	7.0%
16	INT_DISTPT_SUBTOTAL	100.0%	69.5%	23.1%	0.0%	0.1%	7.3%
17	INT_IND M&R	100.0%	0.0%	26.2%	0.2%	12.9%	60.7%
18	INT_871-879	100.0%	70.1%	24.0%	0.0%	0.1%	5.8%
19	INT_866-893	100.0%	64.9%	25.6%	0.0%	0.2%	9.3%
20	INT_LABOR	100.0%	72.2%	22.5%	0.0%	0.2%	5.1%
21	INT_OM_Exc_A&G,Gas,Uncoll	100.0%	71.8%	22.3%	0.0%	0.1%	5.7%
22	INT_TOTAL PLANT	100.0%	69.5%	23.1%	0.0%	0.1%	7.3%
23	INT_RATEBASE	100.0%	67.5%	24.9%	0.0%	0.1%	7.4%
24	INT_REVENUE REQUIREMENT	100.0%	67.5%	28.1%	0.0%	0.1%	4.2%

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 4 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates

Line No.	Category Description	Total System	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
1	Rate Base						
2	Plant in Service	\$ 911,487,309	\$ 633,259,060	\$ 210,524,631	\$ 221,333	\$ 1,221,247	\$ 66,261,039
3	Accumulated Reserve	(222,245,603)	(163,152,609)	(45,925,086)	(43,706)	(255,608)	(12,868,594)
4	Other Rate Base Items	(79,558,728)	(58,280,289)	(12,750,215)	(12,354)	(154,114)	(8,361,756)
5	Total Rate Base	\$ 609,682,978	\$ 411,826,162	\$ 151,849,330	\$ 165,273	\$ 811,525	\$ 45,030,689
6	Revenue at Current Rates						
7	Gas Service Revenue	\$ 126,854,075	\$ 81,373,978	\$ 34,924,325	\$ 36,991	\$ 912,236	\$ 9,606,545
8	Gas Purchase Revenue	81,721,892	49,914,758	31,735,361	71,774	-	-
9	Other Revenues	1,277,987	1,098,709	169,181	274	204	9,618
10	Total Revenue at Current Rates	\$ 209,853,954	\$ 132,387,445	\$ 66,828,867	\$ 109,039	\$ 912,440	\$ 9,616,163
11	Expenses at Current Rates						
12	Gas Cost Expense	\$ 81,721,892	\$ 49,914,758	\$ 31,735,361	\$ 71,774	\$ -	\$ -
13	O&M and A&G Expenses	59,090,125	42,570,648	13,183,188	11,545	70,519	3,254,225
14	Depreciation and Amortization Expense	36,908,120	27,210,867	7,466,175	7,347	55,558	2,168,173
15	Taxes Other Than Income	7,511,829	5,253,977	1,727,475	1,769	10,519	518,089
16	Current Income Taxes	1,732,354	523,266	894,719	1,168	54,587	258,613
17	Total Expenses at Current Rates	\$ 186,964,320	\$ 125,473,516	\$ 55,006,918	\$ 93,604	\$ 191,183	\$ 6,199,100
18	Operating Income at Current Rates	\$ 22,889,633	\$ 6,913,929	\$ 11,821,949	\$ 15,436	\$ 721,257	\$ 3,417,063
19	Current Rate of Return	3.75%	1.68%	7.79%	9.34%	88.88%	7.59%
20	Relative Rate of Return	1.00	0.45	2.07	2.49	23.67	2.02
21	Current Revenue at Equal Rates of Return						
22	Current Rate of Return	3.75%	3.75%	3.75%	3.75%	3.75%	3.75%
23	Current Operating Income at Equal ROR	\$ 22,889,633	\$ 15,461,396	\$ 5,700,955	\$ 6,205	\$ 30,467	\$ 1,690,610
24	Current Income Taxes - Equal ROR	1,732,354	1,170,163	431,465	470	2,306	127,950
25	Other Expenses - Equal ROR	185,231,967	124,950,250	54,112,198	92,436	136,596	5,940,487
26	Total Current Revenue at Equal Rates of Return	\$ 209,853,954	\$ 141,581,809	\$ 60,244,619	\$ 99,110	\$ 169,370	\$ 7,759,047
27	Current (Subsidies)/Excesses	\$ -	\$ (9,194,364)	\$ 6,584,248	\$ 9,929	\$ 743,070	\$ 1,857,116

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 4 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates

Line No.	Category Description	Total System	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
28	Revenue Requirement at Equal Rates of Return						
29	Required Return	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
30	Required Operating Income	\$ 49,701,356	\$ 33,572,069	\$ 12,378,757	\$ 13,473	\$ 66,156	\$ 3,670,902
31	Operating Income (Deficiency)/Sufficiency	\$ (26,811,723)	\$ (26,658,140)	\$ (556,808)	\$ 1,963	\$ 655,101	\$ (253,839)
32	Expenses at Required Return						
33	Gas Cost Expense	\$ 81,721,892	\$ 49,914,758	\$ 31,735,361	\$ 71,774	\$ -	\$ -
34	O&M and A&G Expenses	59,090,125	42,570,648	13,183,188	11,545	70,519	3,254,225
35	Depreciation and Amortization Expense	36,908,120	27,210,867	7,466,175	7,347	55,558	2,168,173
36	Taxes Other Than Income	7,511,829	5,253,977	1,727,475	1,769	10,519	518,089
37	Current Income Taxes - Equal ROR	1,732,354	1,170,163	431,465	470	2,306	127,950
38	Increase - Federal Income Tax	7,127,176	4,814,235	1,775,114	1,932	9,487	526,407
39	Increase - State Income Tax	1,786,258	1,206,574	444,890	484	2,378	131,932
40	Increase - Bad Debts	160,419	134,563	24,848	-	-	1,008
41	Increase - Annual Filing Fee	82,727	55,880	20,604	22	110	6,110
42	Total Expenses at Required Return	\$ 196,120,899	\$ 132,331,666	\$ 56,809,119	\$ 95,344	\$ 150,877	\$ 6,733,894
43	Total Revenue Requirement at Equal Rates of Return	\$ 245,822,256	\$ 165,903,735	\$ 69,187,877	\$ 108,817	\$ 217,032	\$ 10,404,795
44	Less Gas Purchase Revenue	81,721,892	49,914,758	31,735,361	71,774	-	-
45	Less Other Revenues	1,277,987	1,098,709	169,181	274	204	9,618
46	Total Rate Revenue at Equal Rates of Return	\$ 162,822,376	\$ 114,890,268	\$ 37,283,335	\$ 36,768	\$ 216,828	\$ 10,395,177
47	Base Rate Revenue (Deficiency)/Surplus	\$ (35,968,302)	\$ (33,516,290)	\$ (2,359,010)	\$ 222	\$ 695,408	\$ (788,632)
48	Proposed Margin (Decrease)/Increase	\$ 35,968,302	\$ 23,072,840	\$ 9,902,470	\$ 10,488	\$ 258,656	\$ 2,723,847
49	Total Revenue at Proposed Increase	\$ 245,822,256	\$ 155,460,285	\$ 76,731,337	\$ 119,528	\$ 1,171,096	\$ 12,340,010
50	Less Gas Purchase Revenue	81,721,892	49,914,758	31,735,361	71,774	-	-
51	Less Other Revenues	1,277,987	1,098,709	169,181	274	204	9,618
52	Total Rate Revenue at Proposed Increase	\$ 162,822,376	\$ 104,446,819	\$ 44,826,795	\$ 47,479	\$ 1,170,892	\$ 12,330,392
53	Revenue Conversion Factor	1.3415	1.3415	1.3415	1.3415	1.3415	1.3415
54	Income Increase	\$ 26,811,723	\$ 17,199,105	\$ 7,381,563	\$ 7,818	\$ 192,809	\$ 2,030,428
55	Income at Current Rates	22,889,633	6,913,929	11,821,949	15,436	721,257	3,417,063
56	Proposed Operating Income	\$ 49,701,356	\$ 24,113,034	\$ 19,203,512	\$ 23,254	\$ 914,066	\$ 5,447,491
57	Proposed Return	8.15%	5.86%	12.65%	14.07%	112.64%	12.10%
58	Index of Rate of Return	1.00	0.72	1.55	1.73	13.82	1.48
59	Current Return	3.75%	1.68%	7.79%	9.34%	88.88%	7.59%
60	Index of Rate of Return	1.00	0.45	2.07	2.49	23.67	2.02
61	Proposed Revenue to Cost Ratio	1.00	0.91	1.20	1.29	5.40	1.19
62	Proposed Parity Ratio	1.00	0.91	1.20	1.29	5.40	1.19
63	Current Revenue to Cost Ratio	0.78	0.71	0.94	1.01	4.20	0.92
64	Current Parity Ratio	1.00	0.91	1.20	1.29	5.38	1.18

COLUMBIA GAS OF KENTUCKY, INC.
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Line No.	Account Description	FERC						
		Account	Account Balance	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
1	RATE BASE							
2	Plant in Service							
3	Intangible Plant							
4	Organization	301	521	362	120	0	1	38
5	Misc. Intangible Plant - Plant Related	303	67,763	47,078	15,651	16	91	4,926
6	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	18,003,441	12,507,955	4,158,223	4,372	24,122	1,308,769
7	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	10,172,694	7,067,516	2,349,569	2,470	13,630	739,509
8	Subtotal - Intangible Plant		28,244,419	19,622,911	6,523,564	6,858	37,843	2,053,243
9	Distribution Plant							
10	LAND-CITY GATE & MAIN LINE IND. M & R	374.1	865,478	526,907	248,217	294	-	90,060
11	LAND-OTHER DISTRIBUTION SYSTEMS	374.2	3,989,298	2,428,703	1,144,123	1,355	-	415,117
12	RIGHTS OF WAY	374.5	2,692,649	1,639,297	772,246	915	-	280,191
13	STRUCTURES & IMPROVEMENTS	375	3,638,927	2,215,395	1,043,637	1,236	-	378,658
14	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.4	46,211	-	-	-	46,211	-
15	STRUC & IMPROV-DISTR. IND. M & R	375.6	-	-	-	-	-	-
16	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.7	9,466,014	6,576,547	2,186,349	2,299	12,683	688,137
17	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	707,588	491,599	163,430	172	948	51,438
18	STRUC & IMPROV-COMMUNICATIONS	375.8	132,125	80,438	37,893	45	-	13,749
19	MAINS (Less SMRP)	376	503,400,503	306,472,543	144,374,302	170,988	-	52,382,671
20	MAINS - DS-ML DIRECT ASSIGNMENT	376	-	-	-	-	-	-
21	M & R STATION EQUIP-REG (LESS SMRP)	378	33,227,359	20,228,969	9,529,543	11,286	-	3,457,561
22	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.2	186,002	-	-	-	186,002	-
23	M & R STA EQUIP REG FMV	378.21	(777,092)	(473,097)	(222,869)	(264)	-	(80,862)
24	M & R STA EQUIP-CITY GATE CHECK STA	379	1,555,048	946,720	445,985	528	-	161,815
25	SERVICES (Less SMRP)	380	251,105,625	224,865,562	25,877,003	3,610	-	359,449
26	METERS	381	21,899,898	15,998,191	5,606,755	1,956	-	292,996
27	METERS - AMI	381.1	8,252,969	6,028,913	2,112,904	737	-	110,416
28	METER INSTALLATIONS (Less SMRP)	382	12,571,612	9,183,744	3,218,551	1,123	-	168,194
29	HOUSE REGULATORS (Less SMRP)	383	9,748,687	7,121,556	2,495,833	871	-	130,427
30	HOUSE REGULATOR INSTALLATIONS	384	(396)	(289)	(101)	(0)	-	(5)
31	INDUSTRIAL M & R STATION EQUIPMENT	385	6,222,322	-	1,874,034	14,072	-	4,334,216
32	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385	919,617	-	-	-	919,617	-
33	OTHER EQUIPMENT	387	3,482,821	2,419,703	804,421	846	4,666	253,185
34	Subtotal - Distribution Plant		873,333,264	606,751,401	201,712,258	212,068	1,170,127	63,487,411

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Line No.	Account Description	FERC						
		Account	Account Balance	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
35	General Plant							
36	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	1,602,375	1,113,255	370,098	389	2,147	116,485
37	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	591,397	410,876	136,594	144	792	42,992
38	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	48,924	33,990	11,300	12	66	3,557
39	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	24,462	16,995	5,650	6	33	1,778
40	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394	7,270,103	5,050,930	1,679,163	1,765	9,741	528,504
41	LABORATORY EQUIPMENT	395	59,420	41,282	13,724	14	80	4,320
42	POWER OPERATED EQUIP-GENERAL TOOLS	396	185,547	128,909	42,855	45	249	13,488
43	MISCELLANEOUS EQUIPMENT	398	127,398	88,510	29,425	31	171	9,261
44	Subtotal - General Plant		9,909,627	6,884,748	2,288,809	2,406	13,277	720,385
45	Total Plant in Service		911,487,309	633,259,060	210,524,631	221,333	1,221,247	66,261,039
46	Accumulated Depreciation & Amortization							
47	Intangible Plant							
48	Organization	301	-	-	-	-	-	-
49	Misc. Intangible Plant - Plant Related	303	(59,766)	(41,523)	(13,804)	(15)	(80)	(4,345)
50	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	(7,366,977)	(5,118,233)	(1,701,538)	(1,789)	(9,871)	(535,546)
51	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	(3,085,072)	(2,143,365)	(712,554)	(749)	(4,134)	(224,271)
52	Subtotal - Intangible Plant		(10,511,815)	(7,303,121)	(2,427,895)	(2,553)	(14,084)	(764,162)

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Line No.	Account Description	FERC						
		Account	Account Balance	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
53	Distribution Plant							
54	LAND-CITY GATE & MAIN LINE IND. M & R	374.1	-	-	-	-	-	-
55	LAND-OTHER DISTRIBUTION SYSTEMS	374.2	(438,836)	(267,166)	(125,857)	(149)	-	(45,664)
56	RIGHTS OF WAY	374.5	(1,260,932)	(767,661)	(361,633)	(428)	-	(131,210)
57	STRUCTURES & IMPROVEMENTS	375	(715,365)	(435,518)	(205,165)	(243)	-	(74,439)
58	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.4	(8,012)	-	-	-	(8,012)	-
59	STRUC & IMPROV-DISTR. IND. M & R	375.6	-	-	-	-	-	-
60	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.7	(5,394,576)	(3,747,901)	(1,245,976)	(1,310)	(7,228)	(392,161)
61	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	(705,437)	(490,105)	(162,934)	(171)	(945)	(51,282)
62	STRUC & IMPROV-COMMUNICATIONS	375.8	(25,156)	(15,315)	(7,215)	(9)	-	(2,618)
63	MAINS (Less SMRP)	376	(97,006,543)	(59,058,030)	(27,821,291)	(32,950)	-	(10,094,272)
64	MAINS - DS-ML DIRECT ASSIGNMENT	376	-	-	-	-	-	-
65	M & R STATION EQUIP-REG (LESS SMRP)	378	(1,067,686)	(650,012)	(306,210)	(363)	-	(111,101)
66	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.2	(11,115)	-	-	-	(11,115)	-
67	M & R STA EQUIP REG FMV	378.21	289,236	176,088	82,952	98	-	30,097
68	M & R STA EQUIP-CITY GATE CHECK STA	379	(491,176)	(299,030)	(140,868)	(167)	-	(51,111)
69	SERVICES (Less SMRP)	380	(87,745,650)	(78,576,395)	(9,042,388)	(1,262)	-	(125,605)
70	METERS	381	(2,614,472)	(1,909,909)	(669,350)	(234)	-	(34,979)
71	METERS - AMI	381.1	(3,974,894)	(2,903,717)	(1,017,642)	(355)	-	(53,180)
72	METER INSTALLATIONS (Less SMRP)	382	(5,710,480)	(4,171,588)	(1,461,982)	(510)	-	(76,400)
73	HOUSE REGULATORS (Less SMRP)	383	(4,232,936)	(3,092,220)	(1,083,705)	(378)	-	(56,632)
74	HOUSE REGULATOR INSTALLATIONS	384	799	584	205	0	-	11
75	INDUSTRIAL M & R STATION EQUIPMENT	385	(1,536,097)	-	(462,640)	(3,474)	-	(1,069,982)
76	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385	(209,137)	-	-	-	(209,137)	-
77	OTHER EQUIPMENT	387	(427,508)	(297,013)	(98,741)	(104)	(573)	(31,078)
78	Subtotal - Distribution Plant		(213,285,971)	(156,504,908)	(44,130,441)	(42,007)	(237,010)	(12,371,606)

COLUMBIA GAS OF KENTUCKY, INC.
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Line No.	Account Description	FERC						
		Account	Account Balance	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
79	General Plant							
80	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	(545,605)	(379,061)	(126,017)	(132)	(731)	(39,663)
81	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	(218,406)	(151,739)	(50,445)	(53)	(293)	(15,877)
82	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	(18,294)	(12,710)	(4,225)	(4)	(25)	(1,330)
83	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	(45,109)	(31,339)	(10,419)	(11)	(60)	(3,279)
84	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394	(2,290,578)	(1,591,387)	(529,051)	(556)	(3,069)	(166,515)
85	LABORATORY EQUIPMENT	395	-	-	-	-	-	-
86	POWER OPERATED EQUIP-GENERAL TOOLS	396	(172,402)	(119,777)	(39,819)	(42)	(231)	(12,533)
87	MISCELLANEOUS EQUIPMENT	398	(78,542)	(54,567)	(18,141)	(19)	(105)	(5,710)
88	Subtotal - General Plant		(3,368,936)	(2,340,580)	(778,117)	(818)	(4,514)	(244,907)
89	Other Assets							
90	Retirement Work in Progress	N/A	4,921,119	2,996,000	1,411,368	1,672	-	512,080
91	Subtotal - Other Assets		4,921,119	2,996,000	1,411,368	1,672	-	512,080
92	Total Accumulated Depreciation & Amortization		(222,245,603)	(163,152,609)	(45,925,086)	(43,706)	(255,608)	(12,868,594)
93	Other Rate Base Items							
94	Accumulated deferred income taxes	190	(115,024,371)	(79,913,592)	(26,566,978)	(27,931)	(154,114)	(8,361,756)
95	Materials & Supplies	154	-	-	-	-	-	-
96	Gas Stored Underground	164	35,465,643	21,633,303	13,816,763	15,577	-	-
97	Total Other Rate Base Items		(79,558,728)	(58,280,289)	(12,750,215)	(12,354)	(154,114)	(8,361,756)
98	TOTAL RATE BASE		609,682,978	411,826,162	151,849,330	165,273	811,525	45,030,689

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Line No.	Account Description	FERC Account	Account Balance	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
99	OPERATION AND MAINTENANCE EXPENSE							
100	Production, Storage, LNG, Transmission, and Distribution Expense							
101	Other Gas Supply Expenses							
102	Natural gas well head purchases	801-803	77,159,140	47,127,883	29,963,490	67,767	-	-
103	Natural Gas City Gate Purchases	804	3,713,241	2,268,003	1,441,976	3,261	-	-
104	Other gas purchases	805	719,988	439,760	279,595	632	-	-
105	Exchange gas	806	(969,882)	(592,393)	(376,638)	(852)	-	-
106	Gas Withdrawn from Storage	808	1,221,419	746,028	474,318	1,073	-	-
107	Gas Used for Other Utility Operations	812	(122,013)	(74,524)	(47,382)	(107)	-	-
108	Exchange Fees	813	-	-	-	-	-	-
109	Purchased Gas Expense	807	346,462	211,615	134,543	304	-	-
110	Subtotal - Other Gas Supply Expenses		82,068,354	50,126,372	31,869,903	72,078	-	-
111	Operation Expenses							
112	Transmission Expense - Operations	852	16,280	9,911	4,669	6	-	1,694
113	Other expenses	859	-	-	-	-	-	-
114	M&R Station Equipment	865	-	-	-	-	-	-
115	Operation supervision and engineering	870	1,147,127	804,201	275,273	226	1,294	66,134
116	Distribution load dispatching	871	183,031	63,877	48,492	84	-	70,579
117	Mains and services expenses	874	7,644,633	5,383,502	1,724,981	1,769	-	534,382
118	Measuring and regulating station expenses—general	875	357,433	217,607	102,511	121	-	37,194
119	Measuring and regulating station expenses—industrial	876	119,377	-	31,324	235	15,371	72,446
120	Meter and house regulator expenses	878	1,952,775	1,426,530	499,944	174	-	26,126
121	Customer installations expenses	879	3,373,937	2,464,710	863,787	301	-	45,140
122	OTHER EXPENSE	880	2,077,348	1,456,337	498,496	409	2,343	119,763
123	TELECOMMUNICATION EXPENSE - ENGINEERING	881	29,478	20,666	7,074	6	33	1,699
124	Subtotal - Operation Expenses		16,901,420	11,847,340	4,056,551	3,332	19,041	975,156
125	Maintenance Expenses							
126	Maintenance supervision and engineering	885	110,855	71,946	28,396	34	220	10,259
127	Maintenance of structures and improvements	886	254,031	154,655	72,856	86	-	26,434
128	Maintenance of mains	887	3,449,522	2,100,085	989,316	1,172	-	358,949
129	Maintenance of measuring and regulating station equipment—general	889	665,447	405,127	190,849	226	-	69,245
130	Maintenance of measuring and regulating station equipment—industrial	890	84,976	-	22,298	167	10,942	51,569
131	Maintenance of services	892	877,715	785,995	90,451	13	-	1,256
132	Maintenance of meters and house regulators	893	177,057	129,343	45,330	16	-	2,369
133	Maintenance of other equipment	894	412,686	267,835	105,712	126	820	38,193
134	Subtotal - Maintenance Expenses		6,032,290	3,914,987	1,545,207	1,840	11,982	558,275
135	Total Production, Storage, LNG, Transmission, and Distribution Expense		105,002,064	65,888,699	37,471,662	77,250	31,022	1,533,432

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Line No.	Account Description	FERC						
		Account	Account Balance	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
136	Customer Accounts, Service, and Sales Expense							
137	Customer Account							
138	Supervision	901	-	-	-	-	-	-
139	Meter reading expenses	902	310,029	278,910	30,966	4	7	142
140	Customer records and collection expenses	903	3,127,972	2,814,002	312,426	45	67	1,432
141	Uncollectible accounts	904	1,252,775	1,050,860	194,046	-	-	7,869
142	Miscellaneous customer accounts expenses	905	30,449	27,393	3,041	0	1	14
143	Subtotal - Customer Account		4,721,225	4,171,165	540,480	50	74	9,457
144	Customer Service & Information Expenses							
145	Supervision	907	-	-	-	-	-	-
146	Customer assistance expenses	908	105,607	95,007	10,548	2	2	48
147	Informational and instructional advertising expenses	909	3,530	3,175	353	0	0	2
148	Miscellaneous customer service and informational expenses	910	298,769	268,780	29,841	4	6	137
149	Subtotal - Customer Service & Information Expenses		407,905	366,962	40,742	6	9	187
150	Sales Expenses							
151	Supervision	911	-	-	-	-	-	-
152	Demonstrating and selling expenses	912	1,284	1,156	128	0	0	1
153	Advertising expenses	913	-	-	-	-	-	-
154	Miscellaneous sales expenses	916	-	-	-	-	-	-
155	Subtotal - Sales Expenses		1,284	1,156	128	0	0	1
156	Total Customer Accounts, Service, and Sales Expense		5,130,415	4,539,282	581,350	55	83	9,645
157	Administrative and General Expenses							
158	Administrative and general salaries	920	11,434,627	8,210,147	2,554,242	2,229	13,266	654,742
159	Office supplies and expenses	921	1,177,047	845,129	262,926	229	1,366	67,397
160	Outside services employed	923	7,781,408	5,587,109	1,738,194	1,517	9,028	445,560
161	Property insurance	924	59,157	42,475	13,214	12	69	3,387
162	Injuries and damages	925	1,541,664	1,113,236	347,046	308	2,612	78,462
163	Employee pensions and benefits	926	5,614,427	4,054,179	1,263,873	1,121	9,511	285,743
164	Regulatory commission expenses	928	1,671,790	1,200,357	373,441	326	1,940	95,726
165	General advertising expenses	930.1	9,938	7,136	2,220	2	12	569
166	Miscellaneous general expenses	930.2	(147,349)	(105,798)	(32,915)	(29)	(171)	(8,437)
167	Rents	931	780,512	560,414	174,349	152	906	44,692
168	Maintenance of general plant	932	756,318	543,042	168,945	147	877	43,306
169	Total Administrative and General Expenses		30,679,539	22,057,425	6,865,537	6,015	39,414	1,711,149
170	TOTAL OPERATION AND MAINTENANCE EXPENSE		140,812,018	92,485,406	44,918,548	83,320	70,519	3,254,225

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Line No.	Account Description	FERC						
		Account	Account Balance	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
171	Adjustments, Depreciation and Amortization Expense							
172	Depreciation Expense							
173	Intangible Plant							
174	Organization	301	-	-	-	-	-	-
175	Misc. Intangible Plant - Plant Related	303	2,259	1,569	522	1	3	164
176	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	3,257,470	2,263,139	752,372	791	4,364	236,803
177	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	2,111,058	1,466,665	487,587	513	2,828	153,464
178	Subtotal - Intangible Plant		5,370,786	3,731,373	1,240,481	1,304	7,196	390,432
179	Distribution Plant							
180	LAND-CITY GATE & MAIN LINE IND. M & R	374.1	-	-	-	-	-	-
181	LAND-OTHER DISTRIBUTION SYSTEMS	374.2	-	-	-	-	-	-
182	RIGHTS OF WAY	374.5	43,082	26,229	12,356	15	-	4,483
183	STRUCTURES & IMPROVEMENTS	375	105,465	64,207	30,247	36	-	10,974
184	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.4	850	-	-	-	850	-
185	STRUC & IMPROV-DISTR. IND. M & R	375.6	-	-	-	-	-	-
186	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.7	284,927	197,954	65,809	69	382	20,713
187	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	25,046	17,401	5,785	6	34	1,821
188	STRUC & IMPROV-COMMUNICATIONS	375.8	3,448	2,099	989	1	-	359
189	MAINS (Less SMRP)	376	11,973,529	7,289,540	3,433,985	4,067	-	1,245,937
190	MAINS - DS-ML DIRECT ASSIGNMENT	376	-	-	-	-	-	-
191	M & R STATION EQUIP-REG (LESS SMRP)	378	1,158,744	705,448	332,325	394	-	120,576
192	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.2	5,022	-	-	-	5,022	-
193	M & R STA EQUIP REG FMV	378.21	(25,730)	(15,665)	(7,379)	(9)	-	(2,677)
194	M & R STA EQUIP-CITY GATE CHECK STA	379	47,273	28,780	13,558	16	-	4,919
195	SERVICES (Less SMRP)	380	14,624,949	13,096,670	1,507,134	210	-	20,935
196	METERS	381	907,433	662,893	232,319	81	-	12,140
197	METERS - AMI	381.1	584,377	426,896	149,611	52	-	7,818
198	METER INSTALLATIONS (Less SMRP)	382	363,522	265,558	93,068	32	-	4,864
199	HOUSE REGULATORS (Less SMRP)	383	273,943	200,119	70,134	24	-	3,665
200	HOUSE REGULATOR INSTALLATIONS	384	(0)	(0)	(0)	(0)	-	(0)
201	INDUSTRIAL M & R STATION EQUIPMENT	385	384,328	-	115,751	869	-	267,707
202	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385	41,088	-	-	-	41,088	-
203	OTHER EQUIPMENT	387	188,670	131,079	43,577	46	253	13,715
204	Subtotal - Distribution Plant		30,989,966	23,099,209	6,099,269	5,910	47,628	1,737,950

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 5 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC						
		Account	Account Balance	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
205	General Plant							
206	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	88,131	61,229	20,355	21	118	6,407
207	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	121,236	84,229	28,002	29	162	8,813
208	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	685	476	158	0	1	50
209	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	342	238	79	0	0	25
210	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394	327,312	227,401	75,599	79	439	23,794
211	LABORATORY EQUIPMENT	395	-	-	-	-	-	-
212	POWER OPERATED EQUIP-GENERAL TOOLS	396	928	645	214	0	1	67
213	MISCELLANEOUS EQUIPMENT	398	8,733	6,067	2,017	2	12	635
214	Subtotal - General Plant		547,367	380,285	126,424	133	733	39,791
215	Total - Depreciation Expense		36,908,120	27,210,867	7,466,175	7,347	55,558	2,168,173
216	Total Adjustments, Depreciation and Amortization Expense		36,908,120	27,210,867	7,466,175	7,347	55,558	2,168,173
217	Taxes							
218	Taxes Other Than Income Taxes							
219	Taxes Other Than Income Taxes - Property	408.1	6,228,059	4,326,966	1,438,484	1,512	8,345	452,752
220	Taxes Other Than Income Taxes - Payroll	408.2	1,055,370	762,083	237,576	211	1,788	53,712
221	Taxes Other Than Income Taxes - Other	408.3	228,400	164,928	51,415	46	387	11,624
222	Subtotal - Taxes Other Than Income Taxes		7,511,829	5,253,977	1,727,475	1,769	10,519	518,089
223	Income Taxes							
224	FEDERAL INCOME TAXES	409.1	(4,181,717)	(2,824,649)	(1,041,510)	(1,134)	(5,566)	(308,858)
225	STATE INCOME TAXES	409.2	(1,212,778)	(819,203)	(302,058)	(329)	(1,614)	(89,575)
226	DEFERRED INCOME TAX EXPENSE - FEDERAL	410-411.1	5,458,256	3,686,920	1,359,448	1,480	7,265	403,142
227	DEFERRED INCOME TAX EXPENSE - FEDERAL	410-411.2	1,668,593	1,127,095	415,584	452	2,221	123,241
228	Subtotal - Income Taxes		1,732,354	1,170,163	431,465	470	2,306	127,950
229	Total Taxes		9,244,183	6,424,140	2,158,940	2,238	12,825	646,039
230	REVENUE REQUIREMENT AT EQUAL RATES OF RETURN							
231	Test Year Expenses at Current Rates		186,964,320	126,120,413	54,543,663	92,905	138,902	6,068,437
232	Return on Rate Base		49,701,356	33,572,069	12,378,757	13,473	66,156	3,670,902
233	Gross Up Items							
234	Gross-up Federal Income Tax		7,127,176	4,814,235	1,775,114	1,932	9,487	526,407
235	Gross-up State Utility Tax		1,786,258	1,206,574	444,890	484	2,378	131,932
236	Gross-up Bad Debts		160,419	134,563	24,848	-	-	1,008
237	Gross-up Annual Filing Fee		82,727	55,880	20,604	22	110	6,110
238	TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN		245,822,256	165,903,735	69,187,877	108,817	217,032	10,404,795

COLUMBIA GAS OF KENTUCKY, INC.

Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods

FORECASTED PERIOD 12/31/2026 TO 12/31/2027

Attachment RJA-2, Schedule 6 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
1	Functional Rate Base						
2	Distribution						
3	Demand	\$ 340,436,865	\$ 179,662,105	\$ 118,946,256	\$ 149,936	\$ 145,334	\$ 41,533,234
4	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Customer	\$ 94,772,920	\$ 85,221,295	\$ 9,461,728	\$ 1,356	\$ 45,164	\$ 43,378
6	Subtotal	\$ 435,209,785	\$ 264,883,400	\$ 128,407,984	\$ 151,291	\$ 190,498	\$ 41,576,611
7	On Site						
8	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
9	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10	Customer	\$ 174,473,193	\$ 146,942,762	\$ 23,441,346	\$ 13,981	\$ 621,027	\$ 3,454,078
11	Subtotal	\$ 174,473,193	\$ 146,942,762	\$ 23,441,346	\$ 13,981	\$ 621,027	\$ 3,454,078
12	Cust Accts						
13	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
14	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
15	Customer	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
16	Subtotal	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17	Gas Costs						
18	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
19	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
20	Customer	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
21	Subtotal	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
37	Total						
38	Demand	\$ 340,436,865	\$ 179,662,105	\$ 118,946,256	\$ 149,936	\$ 145,334	\$ 41,533,234
39	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
40	Customer	\$ 269,246,114	\$ 232,164,057	\$ 32,903,074	\$ 15,337	\$ 666,191	\$ 3,497,455
41	TOTAL RATE BASE	\$ 609,682,978	\$ 411,826,162	\$ 151,849,330	\$ 165,273	\$ 811,525	\$ 45,030,689

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 6 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
42	Functional Revenue Requirement						
43	Distribution						
44	Demand	\$ 68,782,598	\$ 35,969,193	\$ 23,871,712	\$ 30,303	\$ 21,491	\$ 8,889,900
45	Commodity	\$ 560,511	\$ 342,354	\$ 217,665	\$ 492	\$ -	\$ -
46	Customer	\$ 20,780,595	\$ 18,414,860	\$ 2,157,183	\$ 518	\$ 6,679	\$ 201,356
47	Subtotal	\$ 90,123,705	\$ 54,726,406	\$ 26,246,560	\$ 31,313	\$ 28,169	\$ 9,091,256
48	On Site						
49	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
50	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
51	Customer	\$ 63,864,982	\$ 52,251,775	\$ 10,118,246	\$ 5,606	\$ 188,676	\$ 1,300,679
52	Subtotal	\$ 63,864,982	\$ 52,251,775	\$ 10,118,246	\$ 5,606	\$ 188,676	\$ 1,300,679
53	Cust Accts						
54	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
55	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
56	Customer	\$ 10,111,676	\$ 9,010,796	\$ 1,087,709	\$ 124	\$ 187	\$ 12,860
57	Subtotal	\$ 10,111,676	\$ 9,010,796	\$ 1,087,709	\$ 124	\$ 187	\$ 12,860
58	Gas Costs						
59	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
60	Commodity	\$ 81,721,892	\$ 49,914,758	\$ 31,735,361	\$ 71,774	\$ -	\$ -
61	Customer	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
62	Subtotal	\$ 81,721,892	\$ 49,914,758	\$ 31,735,361	\$ 71,774	\$ -	\$ -
78	Total						
79	Demand	\$ 68,782,598	\$ 35,969,193	\$ 23,871,712	\$ 30,303	\$ 21,491	\$ 8,889,900
80	Commodity	\$ 82,282,404	\$ 50,257,111	\$ 31,953,026	\$ 72,266	\$ -	\$ -
81	Customer	\$ 94,757,254	\$ 79,677,431	\$ 13,363,139	\$ 6,248	\$ 195,541	\$ 1,514,895
	TOTAL REVENUE REQUIREMENT AT EQUAL	\$ 245,822,256	\$ 165,903,735	\$ 69,187,877	\$ 108,817	\$ 217,032	\$ 10,404,795
82	RATES OF RETURN						
83	Demand	27.98%	21.68%	34.50%	27.85%	9.90%	85.44%
84	Energy	33.47%	30.29%	46.18%	66.41%	0.00%	0.00%
85	Customer	38.55%	48.03%	19.31%	5.74%	90.10%	14.56%

COLUMBIA GAS OF KENTUCKY, INC.

Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods

FORECASTED PERIOD 12/31/2026 TO 12/31/2027

Attachment RJA-2, Schedule 6 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS
86	Unit Costs						
87	Distribution						
88	Demand	\$ 16.94	\$ 21.58	\$ 22.43	\$ 25.25	\$ 0.02	\$ 217.89
89	Commodity	\$ 0.02	\$ 0.04	\$ 0.04	\$ 0.05	\$ -	\$ -
90	Customer	\$ 12.39	\$ 12.20	\$ 12.88	\$ 21.58	\$ 185.51	\$ 262.18
91	On Site						
92	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
93	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
94	Customer	\$ 38.08	\$ 34.63	\$ 60.40	\$ 233.56	\$ 5,241.00	\$ 1,693.59
95	Cust Accts						
96	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
97	Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
98	Customer	\$ 6.03	\$ 5.97	\$ 6.49	\$ 5.19	\$ 5.19	\$ 16.74
99	Gas Costs						
100	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
101	Commodity	\$ 3.45	\$ 6.17	\$ 5.17	\$ 6.77	\$ -	\$ -
102	Customer	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
115	Total						
116	Commodity	\$ 3.4712	\$ 6.2111	\$ 5.2018	\$ 6.8169	\$ -	\$ -
117	Customer (per cust month)	\$ 56.50	\$ 52.81	\$ 79.77	\$ 260.33	\$ 5,431.70	\$ 1,972.52
118	Demand & Customer (per cust month)	\$ 97.51	\$ 76.65	\$ 222.27	\$ 1,522.93	\$ 6,028.67	\$ 13,547.91
119	BILLING DETERMINANTS						
120	Demand (Peak Day Demand * 12)	4,059,362	1,666,562	1,064,400	1,200	1,286,400	40,800
121	Commodity	23,704,470	8,091,498	6,142,658	10,601	519,300	8,940,413
122	Customers (Number of Bills)	1,677,192	1,508,844	167,520	24	36	768

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Customer-Demand Method (Zero-Intercept)
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 7 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
1	RATE BASE								
2	Plant in Service								
3	Intangible Plant								
4	Organization	301.0	521	INT_DISTPT_SUBTOTAL					
5	Misc. Intangible Plant - Plant Related	303.0	67,763	INT_DISTPT_SUBTOTAL					
6	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	18,003,441	INT_DISTPT_SUBTOTAL					
7	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	10,172,694	INT_DISTPT_SUBTOTAL					
8	Subtotal - Intangible Plant		28,244,419						
9	Distribution Plant								
10	LAND-CITY GATE & MAIN LINE IND. M & R	374.1	865,478		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
11	LAND-OTHER DISTRIBUTION SYSTEMS	374.2	3,989,298		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
12	RIGHTS OF WAY	374.5	2,692,649		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
13	STRUCTURES & IMPROVEMENTS	375.0	3,638,927		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
14	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.4	46,211		DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT		DS-ML_DIRECT
15	STRUC & IMPROV-DISTR. IND. M & R	375.6	0		ON SITE	CUSTOMER			IND_M&R_ACCT 385
16	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.7	9,466,014	INT_DISTPT_SUBTOTAL					
17	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	707,588	INT_DISTPT_SUBTOTAL					
18	STRUC & IMPROV-COMMUNICATIONS	375.8	132,125		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
19	MAINS (Less SMRP)	376.0	503,400,503		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
20	MAINS - DS-ML DIRECT ASSIGNMENT	376.0	0		DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT		DS-ML_DIRECT
21	M & R STATION EQUIP-REG (LESS SMRP)	378.0	33,227,359		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
22	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.2	186,002		DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT		DS-ML_DIRECT
23	M & R STA EQUIP REG FMV	378.2	(777,092)		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
24	M & R STA EQUIP-CITY GATE CHECK STA	379.0	1,555,048		DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML		CUSTOMERS EXCL DS-ML
25	SERVICES (Less SMRP)	380.0	251,105,625		ON SITE	CUSTOMER			SERVICES_ACCT 380
26	METERS	381.0	21,899,898		ON SITE	CUSTOMER			METERS_ACCT 381
27	METERS - AMI	381.1	8,252,969		ON SITE	CUSTOMER			METERS_ACCT 381
28	METER INSTALLATIONS (Less SMRP)	382.0	12,571,612		ON SITE	CUSTOMER			METERS_ACCT 381
29	HOUSE REGULATORS (Less SMRP)	383.0	9,748,687		ON SITE	CUSTOMER			METERS_ACCT 381
30	HOUSE REGULATOR INSTALLATIONS	384.0	(396)		ON SITE	CUSTOMER			METERS_ACCT 381
31	INDUSTRIAL M & R STATION EQUIPMENT	385.0	6,222,322		ON SITE	CUSTOMER			IND_M&R_ACCT 385
32	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385.0	919,617		ON SITE	CUSTOMER			DS-ML_DIRECT
33	OTHER EQUIPMENT	387.00	3,482,821	INT_DISTPT_SUBTOTAL					
34	Subtotal - Distribution Plant		873,333,264						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Customer-Demand Method (Zero-Intercept)
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 7 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
35	General Plant								
36	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	1,602,375	INT_DISTPT_SUBTOTAL					
37	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	591,397	INT_DISTPT_SUBTOTAL					
38	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	48,924	INT_DISTPT_SUBTOTAL					
39	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	24,462	INT_DISTPT_SUBTOTAL					
40	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	7,270,103	INT_DISTPT_SUBTOTAL					
41	LABORATORY EQUIPMENT	395.0	59,420	INT_DISTPT_SUBTOTAL					
42	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	185,547	INT_DISTPT_SUBTOTAL					
43	MISCELLANEOUS EQUIPMENT	398.0	127,398	INT_DISTPT_SUBTOTAL					
44	Subtotal - General Plant		9,909,627						
45	Total Plant in Service		911,487,309						
46	Accumulated Depreciation & Amortization								
47	Intangible Plant								
48	Organization	301.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
49	Misc. Intangible Plant - Plant Related	303.0	(59,766)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
50	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	(7,366,977)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
51	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	(3,085,072)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
52	Subtotal - Intangible Plant		(10,511,815)						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Customer-Demand Method (Zero-Intercept)
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 7 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor	
53	Distribution Plant									
54	LAND-CITY GATE & MAIN LINE IND. M & R		374.1	0	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
55	LAND-OTHER DISTRIBUTION SYSTEMS		374.2	(438,836)	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
56	RIGHTS OF WAY		374.5	(1,260,932)	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
57	STRUCTURES & IMPROVEMENTS		375.0	(715,365)	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
58	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT		375.4	(8,012)	-	DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT	-	DS-ML_DIRECT
59	STRUC & IMPROV-DISTR. IND. M & R		375.6	0	-	ON SITE	CUSTOMER	-	-	IND_M&R_ACCT 385
60	STRUC & IMPROV-OTHER DISTR. SYSTEMS		375.7	(5,394,576)		INT_DISTPT_SUBTOTAL	-	-	-	-
61	STRUC & IMPROV-OTHER DISTR SYS-ILP		375.71	(705,437)		INT_DISTPT_SUBTOTAL	-	-	-	-
62	STRUC & IMPROV-COMMUNICATIONS		375.80	(25,156)	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
63	MAINS (Less SMRP)		376.00	(97,006,543)	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
64	MAINS - DS-ML DIRECT ASSIGNMENT		376.00	0	-	DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT	-	DS-ML_DIRECT
65	M & R STATION EQUIP-REG (LESS SMRP)		378.00	(1,067,686)	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
66	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT		378.20	(11,115)	-	DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT	-	DS-ML_DIRECT
67	M & R STA EQUIP REG FMV		378.21	289,236	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
68	M & R STA EQUIP-CITY GATE CHECK STA		379.00	(491,176)	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
69	SERVICES (Less SMRP)		380.00	(87,745,650)	-	ON SITE	CUSTOMER	-	-	SERVICES_ACCT 380
70	METERS		381.00	(2,614,472)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
71	METERS - AMI		381.1	(3,974,894)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
72	METER INSTALLATIONS (Less SMRP)		382.0	(5,710,480)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
73	HOUSE REGULATORS (Less SMRP)		383.0	(4,232,936)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
74	HOUSE REGULATOR INSTALLATIONS		384.0	799	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
75	INDUSTRIAL M & R STATION EQUIPMENT		385.0	(1,536,097)	-	ON SITE	CUSTOMER	-	-	IND_M&R_ACCT 385
76	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT		385.0	(209,137)	-	ON SITE	CUSTOMER	-	-	DS-ML_DIRECT
77	OTHER EQUIPMENT		387.0	(427,508)		INT_DISTPT_SUBTOTAL	-	-	-	-
78	Subtotal - Distribution Plant			(213,285,971)						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Customer-Demand Method (Zero-Intercept)
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 7 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
79	General Plant								
80	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	(545,605)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
81	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	(218,406)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
82	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	(18,294)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
83	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	(45,109)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
84	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	(2,290,578)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
85	LABORATORY EQUIPMENT	395.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
86	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	(172,402)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
87	MISCELLANEOUS EQUIPMENT	398.0	(78,542)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
88	Subtotal - General Plant		(3,368,936)						
89	Other Assets								
90	Retirement Work in Progress	N/A	4,921,119	INT_MAINS_PLANT					
91	Subtotal - Other Assets		4,921,119						
92	Total Accumulated Depreciation & Amortization		(222,245,603)						
93	Other Rate Base Items								
94	Accumulated deferred income taxes	190.0	(115,024,371)	INT_TOTAL PLANT					
95	Materials & Supplies	154.0	0	INT_DISTPT_SUBTOTAL					
96	Gas Stored Underground	164.0	35,465,643		DISTRIBUTION	DEMAND	DESIGN DAY EXCL INTERR DEMAND		
97	Total Other Rate Base Items		(79,558,728)						
98	TOTAL RATE BASE		609,682,978						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Customer-Demand Method (Zero-Intercept)
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 7 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor	
99	OPERATION AND MAINTENANCE EXPENSE									
100	Production, Storage, LNG, Transmission, and Distribution Expense									
101	Other Gas Supply Expenses									
102	Natural gas well head purchases	801-803	77,159,140		GAS COSTS	COMMODITY		GAS_COST		
103	Natural Gas City Gate Purchases	804	3,713,241		GAS COSTS	COMMODITY		GAS_COST		
104	Other gas purchases	805	719,988		GAS COSTS	COMMODITY		GAS_COST		
105	Exchange gas	806	(969,882)		GAS COSTS	COMMODITY		GAS_COST		
106	Gas Withdrawn from Storage	808	1,221,419		GAS COSTS	COMMODITY		GAS_COST		
107	Gas Used for Other Utility Operations	812	(122,013)		GAS COSTS	COMMODITY		GAS_COST		
108	Exchange Fees	813	0		GAS COSTS	COMMODITY		GAS_COST		
109	Purchased Gas Expense	807.0	346,462		DISTRIBUTION	COMMODITY		GAS_COST		
110	Subtotal - Other Gas Supply Expenses		82,068,354							
111	Operation Expenses									
112	Transmission Expense - Operations	852	16,280	INT_MAINS_PLANT						
113	Other expenses	859	0	INT_MAINS_PLANT						
114	M&R Station Equipment	865	0	INT_MAINS_PLANT						
115	Operation supervision and engineering	870.0	1,147,127	INT_871-879						
116	Distribution load dispatching	871.0	183,031		DISTRIBUTION	CUSTOMER			THROUGHPUT EXCL DS-ML	
117	Mains and services expenses	874.0	7,644,633	INT_MAINS_SERVICES						
118	Measuring and regulating station expenses—general	875.0	357,433	INT_MAINS_PLANT						
119	Measuring and regulating station expenses—industrial	876.0	119,377	INT_IND M&R						
120	Meter and house regulator expenses	878.0	1,952,775		ON SITE	CUSTOMER			METERS_ACCT 381	
121	Customer installations expenses	879.0	3,373,937		ON SITE	CUSTOMER			METERS_ACCT 381	
122	OTHER EXPENSE	880.0	2,077,348	INT_871-879						
123	TELECOMMUNICATION EXPENSE - ENGINEERING	881.0	29,478	INT_871-879						
124	Subtotal - Operation Expenses		16,901,420							
125	Maintenance Expenses									
126	Maintenance supervision and engineering	885.0	110,855	INT_866-893						
127	Maintenance of structures and improvements	886.0	254,031	INT_MAINS_PLANT						
128	Maintenance of mains	887.0	3,449,522	INT_MAINS_PLANT						
129	Maintenance of measuring and regulating station equipment—general	889.0	665,447	INT_MAINS_PLANT						
130	Maintenance of measuring and regulating station equipment—industrial	890.0	84,976	INT_IND M&R						
131	Maintenance of services	892.0	877,715		ON SITE	CUSTOMER			SERVICES_ACCT 380	
132	Maintenance of meters and house regulators	893.0	177,057		ON SITE	CUSTOMER			METERS_ACCT 381	
133	Maintenance of other equipment	894.0	412,686	INT_866-893						
134	Subtotal - Maintenance Expenses		6,032,290							
135	Total Production, Storage, LNG, Transmission, and Distribution Expense		105,002,064							

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Customer-Demand Method (Zero-Intercept)
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 7 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
136	Customer Accounts, Service, and Sales Expense								
137	Customer Account								
138	Supervision	901.0	0						
139	Meter reading expenses	902.0	310,029		CUST ACCTS	CUSTOMER			CUSTOMERS
140	Customer records and collection expenses	903.0	3,127,972		CUST ACCTS	CUSTOMER			CUSTOMERS
141	Uncollectible accounts	904.0	1,252,775		CUST ACCTS	CUSTOMER			UNCOLLECTIBLES
142	Miscellaneous customer accounts expenses	905.0	30,449		CUST ACCTS	CUSTOMER			CUSTOMERS
143	Subtotal - Customer Account		4,721,225						
144	Customer Service & Information Expenses								
145	Supervision	907.0	0						
146	Customer assistance expenses	908.0	105,607		CUST ACCTS	CUSTOMER			CUSTOMERS
147	Informational and instructional advertising expenses	909.0	3,530		CUST ACCTS	CUSTOMER			CUSTOMERS
148	Miscellaneous customer service and informational expenses	910.0	298,769		CUST ACCTS	CUSTOMER			CUSTOMERS
149	Subtotal - Customer Service & Information Expenses		407,905						
150	Sales Expenses								
151	Supervision	911.0	0						
152	Demonstrating and selling expenses	912.0	1,284		CUST ACCTS	CUSTOMER			CUSTOMERS
153	Advertising expenses	913.0	0		CUST ACCTS	CUSTOMER			CUSTOMERS
154	Miscellaneous sales expenses	916.0	0						
155	Subtotal - Sales Expenses		1,284						
156	Total Customer Accounts, Service, and Sales Expense		5,130,415						
157	Administrative and General Expenses								
158	Administrative and general salaries	920.0	11,434,627	INT_OM_Exc_A&G,Gas,Uncoll					
159	Office supplies and expenses	921.0	1,177,047	INT_OM_Exc_A&G,Gas,Uncoll					
160	Outside services employed	923.0	7,781,408	INT_OM_Exc_A&G,Gas,Uncoll					
161	Property insurance	924.0	59,157	INT_OM_Exc_A&G,Gas,Uncoll					
162	Injuries and damages	925.0	1,541,664	INT_LABOR					
163	Employee pensions and benefits	926.0	5,614,427	INT_LABOR					
164	Regulatory commission expenses	928.0	1,671,790	INT_OM_Exc_A&G,Gas,Uncoll					
165	General advertising expenses	930.1	9,938	INT_OM_Exc_A&G,Gas,Uncoll					
166	Miscellaneous general expenses	930.2	(147,349)	INT_OM_Exc_A&G,Gas,Uncoll					
167	Rents	931.0	780,512	INT_OM_Exc_A&G,Gas,Uncoll					
168	Maintenance of general plant	932.0	756,318	INT_OM_Exc_A&G,Gas,Uncoll					
169	Total Administrative and General Expenses		30,679,539						
170	TOTAL OPERATION AND MAINTENANCE EXPENSE		140,812,018						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Customer-Demand Method (Zero-Intercept)
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 7 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
171	Adjustments, Depreciation and Amortization Expense								
172	Depreciation Expense								
173	Intangible Plant								
174	Organization	301.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
175	Misc. Intangible Plant - Plant Related	303.0	2,259	INT_DISTPT_SUBTOTAL	-	-	-	-	-
176	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	3,257,470	INT_DISTPT_SUBTOTAL	-	-	-	-	-
177	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	2,111,058	INT_DISTPT_SUBTOTAL	-	-	-	-	-
178	Subtotal - Intangible Plant		5,370,786						
179	Distribution Plant								
180	LAND-CITY GATE & MAIN LINE IND. M & R	374.10	0	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
181	LAND-OTHER DISTRIBUTION SYSTEMS	374.20	0	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
182	RIGHTS OF WAY	374.50	43,082	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
183	STRUCTURES & IMPROVEMENTS	375.00	105,465	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
184	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.40	850	-	DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT	-	DS-ML_DIRECT
185	STRUC & IMPROV-DISTR. IND. M & R	375.60	0	-	ON SITE	CUSTOMER		-	IND_M&R_ACCT 385
186	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.70	284,927	INT_DISTPT_SUBTOTAL	-	-	-	-	-
187	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	25,046	INT_DISTPT_SUBTOTAL	-	-	-	-	-
188	STRUC & IMPROV-COMMUNICATIONS	375.80	3,448	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
189	MAINS (Less SMRP)	376.00	11,973,529	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
190	MAINS - DS-ML DIRECT ASSIGNMENT	376.00	0	-	DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT	-	DS-ML_DIRECT
191	M & R STATION EQUIP-REG (LESS SMRP)	378.00	1,158,744	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
192	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.20	5,022	-	DISTRIBUTION	ZERO_INTERCEPT	DS-ML_DIRECT	-	DS-ML_DIRECT
193	M & R STA EQUIP REG FMV	378.21	(25,730)	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
194	M & R STA EQUIP-CITY GATE CHECK STA	379.00	47,273	-	DISTRIBUTION	ZERO_INTERCEPT	DESIGN DAY EXCL DS-ML	-	CUSTOMERS EXCL DS-ML
195	SERVICES (Less SMRP)	380.00	14,624,949	-	ON SITE	CUSTOMER		-	SERVICES_ACCT 380
196	METERS	381.00	907,433	-	ON SITE	CUSTOMER		-	METERS_ACCT 381
197	METERS - AMI	381.10	584,377	-	ON SITE	CUSTOMER		-	METERS_ACCT 381
198	METER INSTALLATIONS (Less SMRP)	382.00	363,522	-	ON SITE	CUSTOMER		-	METERS_ACCT 381
199	HOUSE REGULATORS (Less SMRP)	383.00	273,943	-	ON SITE	CUSTOMER		-	METERS_ACCT 381
200	HOUSE REGULATOR INSTALLATIONS	384.00	(0)	-	ON SITE	CUSTOMER		-	METERS_ACCT 381
201	INDUSTRIAL M & R STATION EQUIPMENT	385.00	384,328	-	ON SITE	CUSTOMER		-	IND_M&R_ACCT 385
202	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385.00	41,088	-	ON SITE	CUSTOMER		-	DS-ML_DIRECT
203	OTHER EQUIPMENT	387.00	188,670	INT_DISTPT_SUBTOTAL	-	-	-	-	-
204	Subtotal - Distribution Plant		30,989,966						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Customer-Demand Method (Zero-Intercept)
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Schedule 7 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
205	General Plant								
206	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	88,131	INT_DISTPT_SUBTOTAL	-	-	-	-	-
207	OFFICE FURN & EQUIP-INFO SYSTEMS	391.1	121,236	INT_DISTPT_SUBTOTAL	-	-	-	-	-
208	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	685	INT_DISTPT_SUBTOTAL	-	-	-	-	-
209	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.2	342	INT_DISTPT_SUBTOTAL	-	-	-	-	-
210	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	327,312	INT_DISTPT_SUBTOTAL	-	-	-	-	-
211	LABORATORY EQUIPMENT	395.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
212	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	928	INT_DISTPT_SUBTOTAL	-	-	-	-	-
213	MISCELLANEOUS EQUIPMENT	398.0	8,733	INT_DISTPT_SUBTOTAL	-	-	-	-	-
214	Subtotal - General Plant		547,367						
215	Total - Depreciation Expense		36,908,120						
216	Total Adjustments, Depreciation and Amortization Expense		36,908,120						
217	Taxes								
218	Taxes Other Than Income Taxes								
219	Taxes Other Than Income Taxes - Property	408.1	6,228,059	INT_DISTPT_SUBTOTAL					
220	Taxes Other Than Income Taxes - Payroll	408.2	1,055,370	INT_LABOR					
221	Taxes Other Than Income Taxes - Other	408.3	228,400	INT_LABOR					
222	Subtotal - Taxes Other Than Income Taxes		7,511,829						
223	Income Taxes								
224	FEDERAL INCOME TAXES	409.1	(4,181,717)	INT_RATEBASE					
225	STATE INCOME TAXES	409.2	(1,212,778)	INT_RATEBASE					
226	DEFERRED INCOME TAX EXPENSE - FEDERAL	410-411.1	5,458,256	INT_RATEBASE					
227	DEFERRED INCOME TAX EXPENSE - FEDERAL	410-411.2	1,668,593	INT_RATEBASE					
228	Subtotal - Income Taxes		1,732,354						
229	Total Taxes		9,244,183						
230	REVENUE REQUIREMENT AT EQUAL RATES OF RETURN								
231	Test Year Expenses at Current Rates		186,964,320						
232	Return on Rate Base		49,701,356	INT_RATEBASE					
233	Gross Up Items								
234	Gross-up Federal Income Tax		7,127,176	INT_RATEBASE					
235	Gross-up State Utility Tax		1,786,258	INT_RATEBASE					
236	Gross-up Bad Debts		160,419		CUST ACCTS	CUSTOMER			UNCOLLECTIBLES
237	Gross-up Annual Filing Fee		82,727	INT_RATEBASE					
238	TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN		245,822,256						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Demand-Commodity
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Scheduel 8 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
1	RATE BASE								
2	Plant in Service								
3	Intangible Plant								
4	Organization	301.0	521	INT_DISTPT_SUBTOTAL					
5	Misc. Intangible Plant - Plant Related	303.0	67,763	INT_DISTPT_SUBTOTAL					
6	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	18,003,441	INT_DISTPT_SUBTOTAL					
7	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	10,172,694	INT_DISTPT_SUBTOTAL					
8	Subtotal - Intangible Plant		28,244,419						
9	Distribution Plant								
10	LAND-CITY GATE & MAIN LINE IND. M & R	374.1	865,478		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
11	LAND-OTHER DISTRIBUTION SYSTEMS	374.2	3,989,298		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
12	RIGHTS OF WAY	374.5	2,692,649		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
13	STRUCTURES & IMPROVEMENTS	375.0	3,638,927		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
14	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.4	46,211		DISTRIBUTION	DEMAND	DS-ML_DIRECT		DS-ML_DIRECT
15	STRUC & IMPROV-DISTR. IND. M & R	375.6	0		ON SITE	CUSTOMER			IND_M&R_ACCT 385
16	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.7	9,466,014	INT_DISTPT_SUBTOTAL					
17	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	707,588	INT_DISTPT_SUBTOTAL					
18	STRUC & IMPROV-COMMUNICATIONS	375.8	132,125		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
19	MAINS (Less SMRP)	376.0	503,400,503		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
20	MAINS - DS-ML DIRECT ASSIGNMENT	376.0	0		DISTRIBUTION	DEMAND	DS-ML_DIRECT		DS-ML_DIRECT
21	M & R STATION EQUIP-REG (LESS SMRP)	378.0	33,227,359		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
22	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.2	186,002		DISTRIBUTION	DEMAND	DS-ML_DIRECT		DS-ML_DIRECT
23	M & R STA EQUIP REG FMV	378.2	(777,092)		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
24	M & R STA EQUIP-CITY GATE CHECK STA	379.0	1,555,048		DISTRIBUTION	DEMAND	DEMAND_COMMODITY		
25	SERVICES (Less SMRP)	380.0	251,105,625		ON SITE	CUSTOMER			SERVICES_ACCT 380
26	METERS	381.0	21,899,898		ON SITE	CUSTOMER			METERS_ACCT 381
27	METERS - AMI	381.1	8,252,969		ON SITE	CUSTOMER			METERS_ACCT 381
28	METER INSTALLATIONS (Less SMRP)	382.0	12,571,612		ON SITE	CUSTOMER			METERS_ACCT 381
29	HOUSE REGULATORS (Less SMRP)	383.0	9,748,687		ON SITE	CUSTOMER			METERS_ACCT 381
30	HOUSE REGULATOR INSTALLATIONS	384.0	(396)		ON SITE	CUSTOMER			METERS_ACCT 381
31	INDUSTRIAL M & R STATION EQUIPMENT	385.0	6,222,322		ON SITE	CUSTOMER			IND_M&R_ACCT 385
32	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385.0	919,617		ON SITE	CUSTOMER			DS-ML_DIRECT
33	OTHER EQUIPMENT	387.00	3,482,821	INT_DISTPT_SUBTOTAL					
34	Subtotal - Distribution Plant		873,333,264						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Demand-Commodity
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Scheduel 8 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
35	General Plant								
36	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	1,602,375	INT_DISTPT_SUBTOTAL					
37	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	591,397	INT_DISTPT_SUBTOTAL					
38	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	48,924	INT_DISTPT_SUBTOTAL					
39	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	24,462	INT_DISTPT_SUBTOTAL					
40	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	7,270,103	INT_DISTPT_SUBTOTAL					
41	LABORATORY EQUIPMENT	395.0	59,420	INT_DISTPT_SUBTOTAL					
42	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	185,547	INT_DISTPT_SUBTOTAL					
43	MISCELLANEOUS EQUIPMENT	398.0	127,398	INT_DISTPT_SUBTOTAL					
44	Subtotal - General Plant		9,909,627						
45	Total Plant in Service		911,487,309						
46	Accumulated Depreciation & Amortization								
47	Intangible Plant								
48	Organization	301.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
49	Misc. Intangible Plant - Plant Related	303.0	(59,766)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
50	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	(7,366,977)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
51	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	(3,085,072)	INT_DISTPT_SUBTOTAL	-	-	-	-	-
52	Subtotal - Intangible Plant		(10,511,815)						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Demand-Commodity
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Scheduel 8 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
53	Distribution Plant								
54	LAND-CITY GATE & MAIN LINE IND. M & R		374.1	0	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
55	LAND-OTHER DISTRIBUTION SYSTEMS		374.2	(438,836)	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
56	RIGHTS OF WAY		374.5	(1,260,932)	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
57	STRUCTURES & IMPROVEMENTS		375.0	(715,365)	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
58	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT		375.4	(8,012)	-	DISTRIBUTION	DEMAND	DS-ML_DIRECT	DS-ML_DIRECT
59	STRUC & IMPROV-DISTR. IND. M & R		375.6	0	-	ON SITE	CUSTOMER	-	IND_M&R_ACCT 385
60	STRUC & IMPROV-OTHER DISTR. SYSTEMS		375.7	(5,394,576)	INT_DISTPT_SUBTOTAL	-	-	-	-
61	STRUC & IMPROV-OTHER DISTR SYS-ILP		375.71	(705,437)	INT_DISTPT_SUBTOTAL	-	-	-	-
62	STRUC & IMPROV-COMMUNICATIONS		375.80	(25,156)	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
63	MAINS (Less SMRP)		376.00	(97,006,543)	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
64	MAINS - DS-ML DIRECT ASSIGNMENT		376.00	0	-	DISTRIBUTION	DEMAND	DS-ML_DIRECT	DS-ML_DIRECT
65	M & R STATION EQUIP-REG (LESS SMRP)		378.00	(1,067,686)	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
66	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT		378.20	(11,115)	-	DISTRIBUTION	DEMAND	DS-ML_DIRECT	DS-ML_DIRECT
67	M & R STA EQUIP REG FMV		378.21	289,236	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
68	M & R STA EQUIP-CITY GATE CHECK STA		379.00	(491,176)	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-
69	SERVICES (Less SMRP)		380.00	(87,745,650)	-	ON SITE	CUSTOMER	-	SERVICES_ACCT 380
70	METERS		381.00	(2,614,472)	-	ON SITE	CUSTOMER	-	METERS_ACCT 381
71	METERS - AMI		381.1	(3,974,894)	-	ON SITE	CUSTOMER	-	METERS_ACCT 381
72	METER INSTALLATIONS (Less SMRP)		382.0	(5,710,480)	-	ON SITE	CUSTOMER	-	METERS_ACCT 381
73	HOUSE REGULATORS (Less SMRP)		383.0	(4,232,936)	-	ON SITE	CUSTOMER	-	METERS_ACCT 381
74	HOUSE REGULATOR INSTALLATIONS		384.0	799	-	ON SITE	CUSTOMER	-	METERS_ACCT 381
75	INDUSTRIAL M & R STATION EQUIPMENT		385.0	(1,536,097)	-	ON SITE	CUSTOMER	-	IND_M&R_ACCT 385
76	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT		385.0	(209,137)	-	ON SITE	CUSTOMER	-	DS-ML_DIRECT
77	OTHER EQUIPMENT		387.0	(427,508)	INT_DISTPT_SUBTOTAL	-	-	-	-
78	Subtotal - Distribution Plant			(213,285,971)					

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Demand-Commodity
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Scheduel 8 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor	
79	General Plant									
80	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	(545,605)	INT_DISTPT_SUBTOTAL	-	-	-	-	-	
81	OFFICE FURN & EQUIP-INFO SYSTEMS	391.12	(218,406)	INT_DISTPT_SUBTOTAL	-	-	-	-	-	
82	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	(18,294)	INT_DISTPT_SUBTOTAL	-	-	-	-	-	
83	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.21	(45,109)	INT_DISTPT_SUBTOTAL	-	-	-	-	-	
84	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	(2,290,578)	INT_DISTPT_SUBTOTAL	-	-	-	-	-	
85	LABORATORY EQUIPMENT	395.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-	
86	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	(172,402)	INT_DISTPT_SUBTOTAL	-	-	-	-	-	
87	MISCELLANEOUS EQUIPMENT	398.0	(78,542)	INT_DISTPT_SUBTOTAL	-	-	-	-	-	
88	Subtotal - General Plant		(3,368,936)							
89	Other Assets									
90	Retirement Work in Progress	N/A	4,921,119	INT_MAINS_PLANT						
91	Subtotal - Other Assets		4,921,119							
92	Total Accumulated Depreciation & Amortization		(222,245,603)							
93	Other Rate Base Items									
94	Accumulated deferred income taxes	190.0	(115,024,371)	INT_TOTAL PLANT						
95	Materials & Supplies	154.0	0	INT_DISTPT_SUBTOTAL						
96	Gas Stored Underground	164.0	35,465,643		DISTRIBUTION	DEMAND	DESIGN DAY EXCL INTERR DEMAND			
97	Total Other Rate Base Items		(79,558,728)							
98	TOTAL RATE BASE		609,682,978							

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Demand-Commodity
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Scheduel 8 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor	
99	OPERATION AND MAINTENANCE EXPENSE									
100	Production, Storage, LNG, Transmission, and Distribution Expense									
101	Other Gas Supply Expenses									
102	Natural gas well head purchases	801-803	77,159,140		GAS COSTS	COMMODITY		GAS_COST		
103	Natural Gas City Gate Purchases	804	3,713,241		GAS COSTS	COMMODITY		GAS_COST		
104	Other gas purchases	805	719,988		GAS COSTS	COMMODITY		GAS_COST		
105	Exchange gas	806	(969,882)		GAS COSTS	COMMODITY		GAS_COST		
106	Gas Withdrawn from Storage	808	1,221,419		GAS COSTS	COMMODITY		GAS_COST		
107	Gas Used for Other Utility Operations	812	(122,013)		GAS COSTS	COMMODITY		GAS_COST		
108	Exchange Fees	813	0		GAS COSTS	COMMODITY		GAS_COST		
109	Purchased Gas Expense	807.0	346,462		DISTRIBUTION	COMMODITY		GAS_COST		
110	Subtotal - Other Gas Supply Expenses		82,068,354							
111	Operation Expenses									
112	Transmission Expense - Operations	852	16,280	INT_MAINS_PLANT						
113	Other expenses	859	0	INT_MAINS_PLANT						
114	M&R Station Equipment	865	0	INT_MAINS_PLANT						
115	Operation supervision and engineering	870.0	1,147,127	INT_871-879						
116	Distribution load dispatching	871.0	183,031		DISTRIBUTION	CUSTOMER			THROUGHPUT EXCL DS-ML	
117	Mains and services expenses	874.0	7,644,633	INT_MAINS_SERVICES						
118	Measuring and regulating station expenses—general	875.0	357,433	INT_MAINS_PLANT						
119	Measuring and regulating station expenses—industrial	876.0	119,377	INT_IND M&R						
120	Meter and house regulator expenses	878.0	1,952,775		ON SITE	CUSTOMER			METERS_ACCT 381	
121	Customer installations expenses	879.0	3,373,937		ON SITE	CUSTOMER			METERS_ACCT 381	
122	OTHER EXPENSE	880.0	2,077,348	INT_871-879						
123	TELECOMMUNICATION EXPENSE - ENGINEERING	881.0	29,478	INT_871-879						
124	Subtotal - Operation Expenses		16,901,420							
125	Maintenance Expenses									
126	Maintenance supervision and engineering	885.0	110,855	INT_866-893						
127	Maintenance of structures and improvements	886.0	254,031	INT_MAINS_PLANT						
128	Maintenance of mains	887.0	3,449,522	INT_MAINS_PLANT						
129	Maintenance of measuring and regulating station equipment—general	889.0	665,447	INT_MAINS_PLANT						
130	Maintenance of measuring and regulating station equipment—industrial	890.0	84,976	INT_IND M&R						
131	Maintenance of services	892.0	877,715		ON SITE	CUSTOMER			SERVICES_ACCT 380	
132	Maintenance of meters and house regulators	893.0	177,057		ON SITE	CUSTOMER			METERS_ACCT 381	
133	Maintenance of other equipment	894.0	412,686	INT_866-893						
134	Subtotal - Maintenance Expenses		6,032,290							
135	Total Production, Storage, LNG, Transmission, and Distribution Expense		105,002,064							

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Demand-Commodity
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Scheduel 8 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
136	Customer Accounts, Service, and Sales Expense								
137	Customer Account								
138	Supervision	901.0	0						
139	Meter reading expenses	902.0	310,029		CUST ACCTS	CUSTOMER			CUSTOMERS
140	Customer records and collection expenses	903.0	3,127,972		CUST ACCTS	CUSTOMER			CUSTOMERS
141	Uncollectible accounts	904.0	1,252,775		CUST ACCTS	CUSTOMER			UNCOLLECTIBLES
142	Miscellaneous customer accounts expenses	905.0	30,449		CUST ACCTS	CUSTOMER			CUSTOMERS
143	Subtotal - Customer Account		4,721,225						
144	Customer Service & Information Expenses								
145	Supervision	907.0	0						
146	Customer assistance expenses	908.0	105,607		CUST ACCTS	CUSTOMER			CUSTOMERS
147	Informational and instructional advertising expenses	909.0	3,530		CUST ACCTS	CUSTOMER			CUSTOMERS
148	Miscellaneous customer service and informational expenses	910.0	298,769		CUST ACCTS	CUSTOMER			CUSTOMERS
149	Subtotal - Customer Service & Information Expenses		407,905						
150	Sales Expenses								
151	Supervision	911.0	0						
152	Demonstrating and selling expenses	912.0	1,284		CUST ACCTS	CUSTOMER			CUSTOMERS
153	Advertising expenses	913.0	0		CUST ACCTS	CUSTOMER			CUSTOMERS
154	Miscellaneous sales expenses	916.0	0						
155	Subtotal - Sales Expenses		1,284						
156	Total Customer Accounts, Service, and Sales Expense		5,130,415						
157	Administrative and General Expenses								
158	Administrative and general salaries	920.0	11,434,627	INT_OM_Exc_A&G,Gas,Uncoll					
159	Office supplies and expenses	921.0	1,177,047	INT_OM_Exc_A&G,Gas,Uncoll					
160	Outside services employed	923.0	7,781,408	INT_OM_Exc_A&G,Gas,Uncoll					
161	Property insurance	924.0	59,157	INT_OM_Exc_A&G,Gas,Uncoll					
162	Injuries and damages	925.0	1,541,664	INT_LABOR					
163	Employee pensions and benefits	926.0	5,614,427	INT_LABOR					
164	Regulatory commission expenses	928.0	1,671,790	INT_OM_Exc_A&G,Gas,Uncoll					
165	General advertising expenses	930.1	9,938	INT_OM_Exc_A&G,Gas,Uncoll					
166	Miscellaneous general expenses	930.2	(147,349)	INT_OM_Exc_A&G,Gas,Uncoll					
167	Rents	931.0	780,512	INT_OM_Exc_A&G,Gas,Uncoll					
168	Maintenance of general plant	932.0	756,318	INT_OM_Exc_A&G,Gas,Uncoll					
169	Total Administrative and General Expenses		30,679,539						
170	TOTAL OPERATION AND MAINTENANCE EXPENSE		140,812,018						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Demand-Commodity
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Scheduel 8 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
171	Adjustments, Depreciation and Amortization Expense								
172	Depreciation Expense								
173	Intangible Plant								
174	Organization	301.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
175	Misc. Intangible Plant - Plant Related	303.0	2,259	INT_DISTPT_SUBTOTAL	-	-	-	-	-
176	MISC INTANGIBLE PLANT-OTHER SOFTWARE	303.3	3,257,470	INT_DISTPT_SUBTOTAL	-	-	-	-	-
177	MISC INTANGIBLE PLANT-CLOUD SOFTWARE	303.99	2,111,058	INT_DISTPT_SUBTOTAL	-	-	-	-	-
178	Subtotal - Intangible Plant		5,370,786						
179	Distribution Plant								
180	LAND-CITY GATE & MAIN LINE IND. M & R	374.10	0	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
181	LAND-OTHER DISTRIBUTION SYSTEMS	374.20	0	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
182	RIGHTS OF WAY	374.50	43,082	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
183	STRUCTURES & IMPROVEMENTS	375.00	105,465	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
184	STRUC & IMPROV-REGULATING - DS-ML DIRECT ASSIGNMENT	375.40	850	-	DISTRIBUTION	DEMAND	DS-ML_DIRECT	-	DS-ML_DIRECT
185	STRUC & IMPROV-DISTR. IND. M & R	375.60	0	-	ON SITE	CUSTOMER	-	-	IND_M&R_ACCT 385
186	STRUC & IMPROV-OTHER DISTR. SYSTEMS	375.70	284,927	INT_DISTPT_SUBTOTAL	-	-	-	-	-
187	STRUC & IMPROV-OTHER DISTR SYS-ILP	375.71	25,046	INT_DISTPT_SUBTOTAL	-	-	-	-	-
188	STRUC & IMPROV-COMMUNICATIONS	375.80	3,448	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
189	MAINS (Less SMRP)	376.00	11,973,529	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
190	MAINS - DS-ML DIRECT ASSIGNMENT	376.00	0	-	DISTRIBUTION	DEMAND	DS-ML_DIRECT	-	DS-ML_DIRECT
191	M & R STATION EQUIP-REG (LESS SMRP)	378.00	1,158,744	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
192	M & R STA EQUIP-GENERAL-REGULATING - DS-ML DIRECT ASSIGNMENT	378.20	5,022	-	DISTRIBUTION	DEMAND	DS-ML_DIRECT	-	DS-ML_DIRECT
193	M & R STA EQUIP REG FMV	378.21	(25,730)	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
194	M & R STA EQUIP-CITY GATE CHECK STA	379.00	47,273	-	DISTRIBUTION	DEMAND	DEMAND_COMMODITY	-	-
195	SERVICES (Less SMRP)	380.00	14,624,949	-	ON SITE	CUSTOMER	-	-	SERVICES_ACCT 380
196	METERS	381.00	907,433	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
197	METERS - AMI	381.10	584,377	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
198	METER INSTALLATIONS (Less SMRP)	382.00	363,522	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
199	HOUSE REGULATORS (Less SMRP)	383.00	273,943	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
200	HOUSE REGULATOR INSTALLATIONS	384.00	(0)	-	ON SITE	CUSTOMER	-	-	METERS_ACCT 381
201	INDUSTRIAL M & R STATION EQUIPMENT	385.00	384,328	-	ON SITE	CUSTOMER	-	-	IND_M&R_ACCT 385
202	INDUSTRIAL M & R STATION EQUIPMENT - DS-ML DIRECT ASSIGNMENT	385.00	41,088	-	ON SITE	CUSTOMER	-	-	DS-ML_DIRECT
203	OTHER EQUIPMENT	387.00	188,670	INT_DISTPT_SUBTOTAL	-	-	-	-	-
204	Subtotal - Distribution Plant		30,989,966						

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Demand-Commodity
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-2, Scheduel 8 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
205	General Plant								
206	OFFICE FURN & EQUIP-UNSPECIFIED	391.1	88,131	INT_DISTPT_SUBTOTAL	-	-	-	-	-
207	OFFICE FURN & EQUIP-INFO SYSTEMS	391.1	121,236	INT_DISTPT_SUBTOTAL	-	-	-	-	-
208	TRANS EQUIP-TRAILERS OVER \$1,000	392.2	685	INT_DISTPT_SUBTOTAL	-	-	-	-	-
209	TRANS EQUIP-TRAILERS \$1,000 or LESS	392.2	342	INT_DISTPT_SUBTOTAL	-	-	-	-	-
210	TOOLS,SHOP, & GAR EQ-TOOLS & OTHER	394.0	327,312	INT_DISTPT_SUBTOTAL	-	-	-	-	-
211	LABORATORY EQUIPMENT	395.0	0	INT_DISTPT_SUBTOTAL	-	-	-	-	-
212	POWER OPERATED EQUIP-GENERAL TOOLS	396.0	928	INT_DISTPT_SUBTOTAL	-	-	-	-	-
213	MISCELLANEOUS EQUIPMENT	398.0	8,733	INT_DISTPT_SUBTOTAL	-	-	-	-	-
214	Subtotal - General Plant		547,367						
215	Total - Depreciation Expense		36,908,120						
216	Total Adjustments, Depreciation and Amortization Expense		36,908,120						
217	Taxes								
218	Taxes Other Than Income Taxes								
219	Taxes Other Than Income Taxes - Property	408.1	6,228,059	INT_DISTPT_SUBTOTAL					
220	Taxes Other Than Income Taxes - Payroll	408.2	1,055,370	INT_LABOR					
221	Taxes Other Than Income Taxes - Other	408.3	228,400	INT_LABOR					
222	Subtotal - Taxes Other Than Income Taxes		7,511,829						
223	Income Taxes								
224	FEDERAL INCOME TAXES	409.1	(4,181,717)	INT_RATEBASE					
225	STATE INCOME TAXES	409.2	(1,212,778)	INT_RATEBASE					
226	DEFERRED INCOME TAX EXPENSE - FEDERAL	410-411.1	5,458,256	INT_RATEBASE					
227	DEFERRED INCOME TAX EXPENSE - FEDERAL	410-411.2	1,668,593	INT_RATEBASE					
228	Subtotal - Income Taxes		1,732,354						
229	Total Taxes		9,244,183						
230	REVENUE REQUIREMENT AT EQUAL RATES OF RETURN								
231	Test Year Expenses at Current Rates		186,964,320						
232	Return on Rate Base		49,701,356	INT_RATEBASE					
233	Gross Up Items								
234	Gross-up Federal Income Tax		7,127,176	INT_RATEBASE					
235	Gross-up State Utility Tax		1,786,258	INT_RATEBASE					
236	Gross-up Bad Debts		160,419		CUST ACCTS	CUSTOMER			UNCOLLECTIBLES
237	Gross-up Annual Filing Fee		82,727	INT_RATEBASE					
238	TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN		245,822,256						

Attachment RJA-3

COLUMBIA GAS OF KENTUCKY, INC.
Gas Class Cost of Service Study - Average of Customer-Demand and Demand-Commodity Methods
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-3 - Class Revenue Apportionment

Line No.	Description	Total System	GS-RESIDENTIAL	GS-OTHER	IUS	DS-ML	DS/IS	
1	Total Rate Base	\$ 609,682,978	\$ 411,826,162	\$ 151,849,330	\$ 165,273	\$ 811,525	\$ 45,030,689	
2	Gas Service Revenue	\$ 126,854,075	\$ 81,373,978	\$ 34,924,325	\$ 36,991	\$ 912,236	\$ 9,606,545	
3	Gas Purchase Revenue	81,721,892	49,914,758	31,735,361	71,774	-	-	
4	Other Revenues	<u>1,277,987</u>	<u>1,098,709</u>	<u>169,181</u>	<u>274</u>	<u>204</u>	<u>9,618</u>	
5	Total Revenue	\$ 209,853,954	\$ 132,387,445	\$ 66,828,867	\$ 109,039	\$ 912,440	\$ 9,616,163	
6	Total Revenue less Gas Purchases (margin)	\$ 128,132,061	\$ 82,472,687	\$ 35,093,506	\$ 37,265	\$ 912,440	\$ 9,616,163	
7	Current Revenue to Cost Ratio	0.78	0.71	0.94	1.01	4.20	0.92	
8	Current Parity Ratio	1.00	0.91	1.20	1.29	5.38	1.18	
9	Scenario A: Revenues at Equalized Rates of Return							
10	Revenue Increase/(Decrease)	\$ 35,968,302	\$ 33,516,290	\$ 2,359,010	\$ (222)	\$ (695,408)	\$ 788,632	
11	Total Base Rate Revenue at Equalized Rates of Return	\$ 162,822,376	\$ 114,890,268	\$ 37,283,335	\$ 36,768	\$ 216,828	\$ 10,395,177	
12	Other Revenues	<u>1,277,987</u>	<u>1,098,709</u>	<u>169,181</u>	<u>274</u>	<u>204</u>	<u>9,618</u>	
13	Total Margin at Equalized Rates of Return	\$ 164,100,363	\$ 115,988,977	\$ 37,452,516	\$ 37,043	\$ 217,032	\$ 10,404,795	
14	% Increase of Total Revenues	17.14%	25.32%	3.53%	-0.20%	-76.21%	8.20%	
15	% Increase of Base Rate Revenues	28.35%	41.19%	6.75%	-0.60%	-76.23%	8.21%	
16	Resulting Revenue to Cost Ratio	1.00	1.00	1.00	1.00	1.00	1.00	
17	Resulting Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00	
18	Scenario B: Equal Percentage Increase on Gas Service Revenue							
19	Percent Increase	28.35%	28.35%	28.35%	28.35%	28.35%	28.35%	
20	Revenue Increase/(Decrease)	\$ 35,968,302	\$ 23,072,840	\$ 9,902,470	\$ 10,488	\$ 258,656	\$ 2,723,847	
21	Total Base Rate Revenue	\$ 162,822,376	\$ 104,446,819	\$ 44,826,795	\$ 47,479	\$ 1,170,892	\$ 12,330,392	
22	Other Revenues	<u>1,277,987</u>	<u>1,098,709</u>	<u>169,181</u>	<u>274</u>	<u>204</u>	<u>9,618</u>	
23	Total Margin at Equal Percentage Increase	\$ 164,100,363	\$ 105,545,528	\$ 44,995,976	\$ 47,754	\$ 1,171,096	\$ 12,340,010	
24	Proposed Revenue to Cost Ratio	1.00	0.91	1.20	1.29	5.40	1.19	
25	Proposed Parity Ratio	1.00	0.91	1.20	1.29	5.40	1.19	

Attachment RJA-4

COLUMBIA GAS OF KENTUCKY, INC.
FORECASTED PERIOD 12/31/2026 TO 12/31/2027
Attachment RJA-4, Proposed Rate Design

Customer Class	Pro Forma Test Year Revenues			Proposed Revenues		Difference		
	Billing Units	Present Rates		Proposed Rates	Revenue	\$ Amount	% Amount	
		Margin	Revenue	Margin				
GSR/GTR								
Customer Charge	1,508,673	\$21.25	\$ 32,059,301	\$32.00	\$ 48,277,536	\$ 16,218,235	51%	
Delivery Charge	8,089,316	\$6.09580	\$ 49,310,852	\$6.94320	\$ 56,165,739	\$ 6,854,886	14%	
G1R Base Revenue			\$ 3,134		\$ 3,134	\$ -	0%	
IN3 Base Revenue			\$ 324		\$ 324	\$ -	0%	
IN4 Base Revenue			\$ -		\$ -	\$ -		
IN5 Base Revenue			\$ 72		\$ 72	\$ -	0%	
LG2 - Residential Base Revenue			\$ 144		\$ 144	\$ -	0%	
LG3 - Residential Base Revenue			\$ 152		\$ 152	\$ -	0%	
LG4 - Residential Base Revenue			\$ -		\$ -	\$ -		
Rounding Difference					\$ (281)	\$ (281)		
Total GSR/GTR Revenue			\$ 81,373,979		\$ 104,446,819	\$ 23,072,840	28%	
GSO/GTO/GDS								
Customer Charge	167,521	\$110.00	\$ 18,427,310	\$145.00	\$ 24,290,545	\$ 5,863,235	32%	
Delivery Charge -First 50 Mcf	2,493,773	\$3.15810	\$ 7,875,585	\$3.93130	\$ 9,803,770	\$ 1,928,185	24%	
Delivery Charge -Next 350 Mcf	2,366,483	\$2.43760	\$ 5,768,539	\$3.03440	\$ 7,180,856	\$ 1,412,317	24%	
Delivery Charge -Next 600 Mcf	715,937	\$2.31710	\$ 1,658,898	\$2.88440	\$ 2,065,049	\$ 406,151	24%	
Delivery Charge -Over 1,000 Mcf	566,465	\$2.10780	\$ 1,193,994	\$2.62380	\$ 1,486,290	\$ 292,296	24%	
G1C Base Revenue			\$ -		\$ -	\$ -		
LG2 Commercial Base Revenue			\$ -		\$ -	\$ -		
Rounding Difference					\$ 286	\$ 286		
Total GSO/GTO/GDS Revenue			\$ 34,924,325		\$ 44,826,795	\$ 9,902,470	28%	
IUS								
Customer Charge	24	\$1,135.00	\$ 27,240	\$1,570.00	\$ 37,680	\$ 10,440	38%	
Delivery Charge - All Volumes	10,601	\$0.91980	\$ 9,751	\$0.92440	\$ 9,800	\$ 49	1%	
Rounding Difference					\$ (0)	\$ (0)		
Total IUS Revenue			\$ 36,991		\$ 47,479	\$ 10,488	28%	
DS-ML								
Customer Charge - 25,000 to 400,000 Mcf	36	\$300.00	\$ 10,800	\$2,800.00	\$ 100,800	\$ 90,000	833%	
Customer Charge - 400,000 to 1,000,000 Mcf	12	\$600.00	\$ 7,200	\$4,200.00	\$ 50,400	\$ 43,200	600%	
Customer Charge - Over 1,000,000 Mcf	24	\$600.00	\$ 14,400	\$5,600.00	\$ 134,400	\$ 120,000	833%	
Delivery Charge - all Mcf	9,874,700	\$0.08910	\$ 879,836	\$0.08970	\$ 885,761	\$ 5,925	1%	
Rounding Difference					\$ (469)	\$ (469)		
Total DS-ML Revenue			\$ 912,236		\$ 1,170,892	\$ 258,656	28%	
IS/DS								
Customer Charge	764	\$5,000.00	\$ 3,820,000	\$8,000.00	\$ 6,112,000	\$ 2,292,000	60%	
Delivery Charge - First 30,000 Mcf	6,206,933	\$0.75090	\$ 4,660,786	\$0.80690	\$ 5,008,375	\$ 347,588	7%	
Delivery Charge - Next 70,000 Mcf	2,095,100	\$0.46350	\$ 971,079	\$0.49810	\$ 1,043,569	\$ 72,490	7%	
Delivery Charge - Over 100,000 Mcf	638,380	\$0.24230	\$ 154,679	\$0.26040	\$ 166,234	\$ 11,555	7%	
Rounding Difference					\$ 214	\$ 214		
Total IS/DS Revenue			\$ 9,606,545		\$ 12,330,392	\$ 2,723,847	28%	
Total								
Fixed Charge Recovery		43%	\$ 54,366,251	49%	\$ 79,003,361	\$ 24,637,110		
Volumetric Charge Recovery		57%	\$ 72,483,999	51%	\$ 83,815,441	\$ 11,331,443		
Other Rate Schedules (no change)			\$ 3,825		\$ 3,825	\$ -		
Rounding			\$ -		\$ (251)	\$ (251)		
TOTAL			\$ 126,854,075		\$ 162,822,376	\$ 35,968,302	28%	