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April 6, 2026

VIA ELECTRONIC FILING

eFiling Confirmation Number
2990852

Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: PA Public Utility Commission, *et al.* v. Columbia Gas of Pennsylvania, Inc.
Docket No. R-2026-3060762

Dear Secretary Homsher:

Enclosed for filing on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia") is Supplement No. 415 to Tariff Gas of Pa. PUC No. 9 ("Supplement No. 415"), issued April 1, 2026, with a proposed effective date of October 1, 2026. Supplement 415 is attached to this filing as Exhibit NP-1. Supplement No. 415 is filed pursuant to Section 1307(f) of the Public Utility Code to provide for an annual adjustment and reconciliation of Columbia's gas cost recovery rates. Supplement No. 415 proposes an increase in gas cost recovery rates of $0.04740/therm.

Also enclosed are Columbia's Direct Testimony and related exhibits as required by the Commission's regulations. Columbia has provided an explanation of over/under collections for the twelve-month reconciliation period ending September 2027, which is attached as Revised Exhibit 1-A, Schedule 2, to Statement No. 2. Columbia notes that Revised Exhibits 1-A, Exhibits 1-B, and Revised Exhibit 5 are also included with the filing, with the revisions explained in the corresponding testimony.

Copies of the enclosed filings will be provided as indicated on the Certificate of Service.

Respectfully,

Emily Farah

/kak
Attachments

cc: Administrative Law Judge Emily I. DeVoe (*via email; w/attachments*)
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served upon the following persons, in the manner indicated, in accordance with the requirements of § 1.54 (relating to service by a participant).

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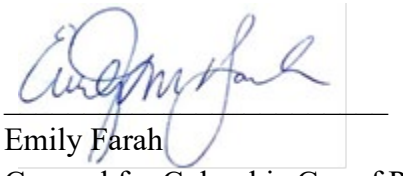

Emily Farah
Counsel for Columbia Gas of Pennsylvania, Inc.

COLUMBIA STATEMENT NO. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2026-3060762
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
TINA M. MONNIG

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2026

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Q. Please state your name and business address.

A. My name is Tina M. Monnig. My business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am Manager of Planning, in the NiSource Corporate Services Company ("NCSC") Supply and Optimization Group, providing services to Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

Q. Please describe your primary supply related responsibilities.

A. I am responsible for activities related to gas supply and capacity planning, including development of detailed long-range plans, short-term operational plans, and strategies to ensure that reliable gas supplies are available and obtained in a best cost manner. In addition, I am responsible for daily operations related to ensuring that gas supplies, pipeline capacity and storage assets are used in a manner consistent with the planning processes and objectives described herein. I am also responsible for the development of Columbia's Design Day Forecast ("DDF"), and the maintenance/analyses of the related daily information used in developing the DDF.

Q. Please describe your professional experience along with your educational background.

A. I have been employed with Columbia/NCSC since 1995. From 1995 to 2014, I was a Planning Analyst and Team Leader for the Supply and Capacity Planning Group. During my tenure in these positions, I was responsible for monthly supply plans and portfolio studies, operational reports and development of the DDF. In 2014, I was

promoted to Manager Planning, overseeing the supply planning, daily operations and demand forecasting responsibilities of the group.

I hold a Bachelor of Science degree in Industrial Management with a minor in Industrial Engineering from Purdue University.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory agency?

A. Yes, I have previously testified in support of Columbia's 2021, 2022, 2023, 2024, 2025 1307(f) filings before the Commission. I have also testified on behalf of Columbia's affiliate company, Columbia Gas of Maryland, Inc., in its annual Purchased Gas Adjustment proceedings before the Maryland Public Service Commission.

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

A. The purpose of my testimony is to:

I. Describe the interstate pipeline services and capacity Columbia utilizes in its least cost purchasing plan and how this capacity compares to Columbia's policy regarding its portfolio design;

II. Describe the gas supply related activities pertaining to Columbia's Customer CHOICE[SM] program; and

III. Illustrate Columbia's activity at the Federal Energy Regulatory Commission ("FERC").

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits, which were included with Columbia's pre-filing data submitted on February 27, 2026:

Number	Description	Regulation
Company Exhibit 2	Contacts of Offers Regarding Historic and Projected Sources of Gas Supply	53.64(c)(3)
Company Exhibit 3	Annotated List of Relevant FERC Proceedings	53.64(c)(4)
Company Exhibit 4	Pa. P.U.C. Form 1 Filing	53.64(c)(5)
Company Exhibit 4-A	Explanation of Variance Between Present and Most Recent Estimated Sales Volumes (Form 1)	53.64(c)(5)
Company Exhibit 4-B	Explanation of Variance Between Actual and Estimated Sales Volumes (Form 1)	53.64(c)(5)
Company Exhibit 5	Statement of Fuel Procurement Practices	53.64(c)(6)
Company Exhibit 10	A Schematic System Map	53.64(c)(10)
Company Exhibit 12	Schedule of Most Recent Five Year Three Day Peak Data by Customer Class	53.64(c)(12)
Company Exhibit 13	Identification and Support for Peak Day Methodology	53.64(c)(13)
Company Exhibit 14	Analysis on an Historic and Future Basis of the Minimum Gas Entitlements Needed to Serve Priority One Customers during Peak Periods	53.64(c)(14)
Company Exhibit 15	Report Supporting Capacity – Level of Peak Day Capacity Retained	

In addition to the pre-filing Exhibits that I sponsor, I am also sponsoring Exhibit TMM-1 and Exhibit TMM-2, which are attached to my testimony. Exhibit TMM-1 shows peak day and annual entitlements, for contract year 2026-27, under Columbia's firm capacity contracts with Columbia Gas Transmission, LLC ("TCO"), Eastern Gas Transmission and Storage, Inc. ("EGTS", formerly Dominion Transmission), Equitrans, L.P. ("Equitrans"), National Fuel Gas Supply Corporation

("National Fuel"), Tennessee Gas Pipeline Company, LLC ("Tennessee" or "TGP"), and Texas Eastern Transmission, LP ("Texas Eastern" or "TETCO"). Exhibit TMM-1 also lists upstream firm pipeline capacity that is utilized to deliver supplies to TCO, namely Tennessee and Texas Eastern. Exhibit TMM-2 shows Columbia's firm peak day supplies and firm demand by contract year.

Q. Are there any updates to the Exhibits you are sponsoring?

A. Yes, Revised Exhibit 5 is being submitted with this testimony to replace the original Exhibit 5 submitted in the 1307(f) pre-filing on February 27, 2026.

Q. Why are you revising Exhibit 5?

A. In Exhibit 5, Table 4, the 2026/27 EGTS firm transportation capacity reflected 4.6 MDth and it should be 5.3 MDth. All subsequent dependent calculations were also corrected using 5.3 MDth. This is not a material change to the exhibit or pre-filing materials.

I. GAS PURCHASING & PROCUREMENT STRATEGIES

Q. Please describe the procedures that Columbia uses to estimate customer requirements.

A. For purposes of the estimates used in this Section 1307(f) filing, Columbia has estimated its customers' seasonal requirements by customer class, assuming 20-year normal weather and expected market conditions. Columbia combines base load and temperature sensitive demand to determine monthly residential and commercial customer requirements. The monthly gas space heating demand for residential and small commercial customers is derived by forecasting customer count and gas use

per customer. The customer count is derived using economic and demographic data (households, real income per capita). The use per customer is derived using weather data throughout Columbia's operations territory and energy intensity. The large commercial customer forecast is developed by the Large Customer Relations group by incorporating information generated through individual customer interviews. Columbia utilizes a grass roots survey of industrial customers to estimate industrial demand. Columbia then estimates customer participation levels under its various transportation programs. These participation levels are deducted from Columbia's demand estimates to establish projected sales levels.

Q. Does Columbia determine customer demand for conditions other than normal weather?

A. Yes. As more fully described in Revised Exhibit 5, for supply planning purposes Columbia determines customer demand under various weather scenarios. Columbia determines customer demand under a colder-than-normal weather scenario to plan its gas supply and capacity portfolio to ensure that it is adequate to meet increased customer demand. Columbia also determines customer demand under a warmer-than-normal weather scenario to plan the flexibility needed in its supply and capacity portfolio to meet reduced customer demand at least cost.

Q. Please describe the conditions Columbia utilizes to define colder-than-normal and warmer-than-normal customer demand.

A. For colder-than-normal demand, Columbia incorporates increased seasonal heating degree-days based upon a 10 percent probability of a colder-than-normal occurrence,

a seasonal peak day at design temperature, and late winter design cold days. For warmer-than-normal demand, Columbia reduces winter season normal heating degree-days based upon a 10 percent probability of a warmer-than-normal occurrence. The 10 percent probability level for the colder-than-normal weather scenario means that there is a 10 percent risk that the winter will have more heating degree-days compared to the planned colder scenario. Conversely, the 10 percent probability for the warmer-than-normal weather scenario means that there is a 10 percent risk that the winter will have less heating degree-days compared to the planned warmer scenario. Columbia utilizes normal weather heating degree-days for the summer season in all demand determinations described herein. On a weighted average basis, for Columbia's service territory, approximately 81 percent of the annual heating degree-days for a normal year occur in the five-month winter season (November - March) and 19 percent in the seven-month summer season (April – October).

Q. Please describe the late winter design cold days and their importance.

A. Columbia utilizes late winter design cold days to test the adequacy of its supply portfolio on cold days late in the winter season, after the planned occurrence of the seasonal design day. As storage supplies are withdrawn, the deliverability of natural gas storage fields declines. Pipeline tariffs recognize this decline and reduce withdrawal entitlements in accordance with the volumes remaining in storage. Due to Columbia's heavy reliance on storage, Columbia utilizes the late winter design cold days to properly manage storage withdrawals and ensure that its capacity portfolio

can reliably meet customer demand on such cold late winter days under all planning scenarios, including the colder-than-normal weather scenario.

Q. Please describe the conditions Columbia utilizes to estimate its design day demand.

A. Columbia's design day demand forecast is based upon the following conditions and considerations:

1) the "design" conditions of
    a. current day design temperature;
    b. prior day design temperature;
    c. current day design wind speed; and
    d. occurrence of the design day on a weekday;
2) an estimate of the number of customers to be served each January for the term of the forecast;
3) forecasted January NYMEX Gas Monthly Price at Henry Hub (NGI Bidweek Prices) for the term of the forecast;
4) actual degree days occurring in the months of December and January for the term of the forecast because these are the two months when Columbia's design conditions are most likely to occur; and
5) average Non-Farm Employment in the months of December through February for the term of the forecast.

All the above factors influence customer demand on Columbia's system on the current day.

The current and prior day design temperatures were developed utilizing all available historic weather data ending with the winter of 2024-25. Columbia updates these design temperatures approximately every five to ten years. The current day design temperature is determined by utilizing a Gumbel Distribution of the annual minimum daily mean temperatures, with a 1 in 15 or 6.67 percent risk factor. That is, the probability is 6.67 percent that any given winter will have one or more days with a mean daily temperature equal to or colder than the current day design temperature.

The prior day design temperature is determined from the mean temperature difference between historical "cold days" and their associated prior days. "Cold days" are defined as those that are no warmer than the current design day temperature plus 5 degrees Fahrenheit.

The design wind speed is based on an analysis of wind activity for the 1990-91 through 2024-25 winter seasons. Columbia updates this wind speed analysis every five to ten years. This analysis determines the average daily wind speed on days that are no warmer than the current design day temperature plus 15 degrees Fahrenheit.

Columbia then utilizes a multiple variable, linear regression analysis of (1) historic daily demand, temperature and wind speed data to determine the design actual daily demand estimate for the most recent year; and (2) a second multiple variable, linear regression analysis of the estimated historic design actuals, January customer counts (historic and forecast), December/January degree days (actual and normal), average non-farm employment (December through February) and retail gas prices (historic and forecast) to develop its design day forecast.

Q. Does Columbia plan for a date of occurrence of a peak day?

A. Yes, Columbia determines the latest date within a winter season, with a 10 percent probability, that a current day design temperature or colder may occur in Columbia's service area. Columbia analyzes the historical dates of occurrence of peak day or colder temperatures to determine this date. Columbia's current planned latest date of peak day occurrence is January 25th.

Q. Does Columbia plan for dates where storage deliverability can be reduced?

A. Yes, for reliability purposes, Columbia determines the lowest temperatures at which firm customer demand can be satisfied immediately after a reduction in storage deliverability. Once Columbia determines these temperatures, the Company then determines the latest dates, with a 10 percent risk, that these temperatures may occur.

Q. What is the importance of these dates?

A. As noted earlier, the deliverability of natural gas storage fields declines as storage supplies are withdrawn. Under the interstate pipeline storage service tariffs utilized by Columbia, the right to withdraw storage volumes is reduced when specific storage inventory levels are reached. These ratcheted reductions in storage withdrawal entitlements occur in steps. Under the Firm Storage Service ("FSS") tariff of TCO, the first step, which reduces storage withdrawal entitlements to 80 percent of the maximum, is reached when remaining storage inventory is less than 30 percent of the seasonal contract quantity. Two additional steps reduce withdrawal entitlements

to 65 percent and 50 percent of maximum. These steps occur when storage inventories fall below 20 percent and 10 percent, respectively. Columbia must manage its storage inventories throughout the winter season to prevent a premature storage deliverability reduction. Such a premature reduction could leave Columbia with insufficient firm supplies to satisfy the demand of firm customers on cold days late in the winter.

II. INTERSTATE PIPELINE SERVICES AND CAPACITY

Q. Please describe Columbia's pipeline services listed on Exhibit TMM-1.

A. As noted on Exhibit TMM-1, for contract year 2026-27, Columbia will receive firm pipeline services from six interstate pipeline companies, namely, TCO, EGTS, Equitrans, National Fuel, Tennessee, and Texas Eastern.

Q. Please describe Columbia's pipeline service from TCO.

A. Columbia contracts for three primary firm services from TCO: Firm Transportation Service ("FTS"), FSS, and Storage Service Transportation ("SST"). The FTS capacity provides for the firm transportation of flowing gas supplies delivered by TCO, either from Appalachian receipt points or interconnects with upstream pipelines, to Columbia's city gates or storage. The FSS capacity provides daily injection and withdrawal capacity into or out of storage, along with firm daily deliverability and seasonal storage capacity. The primary utilization of the SST capacity is providing firm transportation of storage volumes from TCO's storage fields to Columbia's city gates. A secondary use of SST is transporting flowing gas supplies, in excess of Columbia's FTS capacity level, to fill storage during the summer. The use of FSS in

conjunction with SST provides Columbia with its primary daily no-notice balancing service.

Q. Please describe the importance of the TCO capacity to Columbia.

A. Natural Gas Distribution Companies ("NGDCs"), such as Columbia, are fully responsible for the delivery of supplies from producers, marketers, and other supply aggregators to fulfill 100 percent of the supply requirements of sales and CHOICE[SM] customers. For the majority of Columbia's markets, TCO provides the only physical pipeline connection to facilitate such service. Thus, the use of TCO's facilities is critical to Columbia's ability to provide reliable, economic service to its customers. Further, NGDCs are responsible for balancing all deliveries to their city gates on a daily basis, including those supplies delivered to Columbia on behalf of General Distribution Service ("GDS") customers. Columbia's widespread, discrete service territories, large number of city gates, and highly temperature sensitive customer requirements create unique daily balancing challenges.

Because the vast majority of Columbia's market areas are served only by facilities owned by TCO, Columbia is able to utilize its FSS capacity to balance deliveries and demand to all but a handful of its city gates. Columbia's widespread, discrete service areas, and large number of city gates, generally make it uneconomic to construct laterals and interconnections between Columbia and other pipelines. As noted on Exhibit TMM-1, TCO delivers about 81 percent of Columbia's design day supply. As such, Columbia must continue to rely upon its interconnects with TCO to deliver the majority of supplies necessary to meet the requirements of its markets.

Q. Please describe the pipeline and storage services that Columbia receives from other providers.

A. Columbia has six firm transportation contracts and three storage contracts with EGTS. The first transportation contract, provided under EGTS's rate schedule Firm Transportation No-Notice - General Storage Service ("FTNN-GSS"), for 6,000 Dth per day November through March, is utilized to transport storage supplies from EGTS's storage fields to Columbia's city gates. Storage supplies are also transported to Columbia's city gates via a transportation contract under EGTS's rate schedule Firm Transportation ("FT"). This contract has a quantity of 3,000 Dth/day from November through March of each year, and 2,000 Dth/day from April through October of each year. The associated storage contract with EGTS provides Columbia with 9,000 Dth/day of peak day deliverability and approximately 941,176 Dth of seasonal supply. Columbia utilizes these EGTS contracts to provide supplies to its customers in Beaver County through its Darlington interconnect and in Cranberry Township through its Warrendale interconnect.

Columbia has two additional storage contracts and three FTNN and FT transportation contracts with EGTS that are utilized to meet the demand and balancing requirements in the State College market. The storage contracts provide for daily withdrawal of 15,000 Dth/day and 4,800 Dth/day with seasonal quantities of 930,000 Dth and 240,000 Dth, respectively. Columbia utilizes 19,800 Dth/day of Rate Schedule FTNN transportation capacity to deliver the EGTS storage supplies to

the State College market. Additionally, Columbia has 5,000 Dth/day of FT capacity, which it also uses to serve the State College market.

Last, Columbia has 255 Dth/day of FT capacity with EGTS that provides service to a interconnection serving the Centre Hall market.

Columbia also contracts for firm transportation and storage service with Equitrans. The storage service provides peak day deliverability of 19,130 Dth and 2,000,000 Dth of seasonal capacity. The maximum winter season city gate deliveries total 55,000 Dth/day including up to 19,130 Dth from storage. Summer capacity levels are sculpted with 32,000 Dth/day in April and October and 20,000 Dth/day May through September.

Columbia utilizes the Equitrans storage service, approximately 9,559 Dth/day of the associated 19,130 Dth/day of the winter season FTS Transportation Quantity ("TQ"), and the EGTS storage service (3,198 Dth/day) of associated 4,800 Dth/day FTNN transportation contract, discussed above, to provide service to GDS customers under Columbia's Elective Balancing Service ("EBS") Option 1. I will discuss EBS in greater detail later in my testimony.

Columbia currently contracts for firm transportation service with Tennessee totaling 23,600 Dth/day. A total of approximately 19,300 Dth/day is required to serve the design peak day firm customer demand in Columbia markets directly connected to Tennessee, while approximately 4,304 Dth/day is delivered to Columbia's National Fuel capacity. On days when the 19,300 Dth/day delivered directly to Columbia cannot be absorbed by those markets, Columbia can divert that

supply to Tennessee interconnects with TCO for injection into storage or delivery to other Columbia markets that are served by TCO.

Columbia contracts for firm transportation service under two rate schedules with Texas Eastern, FT-1 and Comprehensive Delivery Service ("CDS"), totaling 25,635 Dth/day. A total of 22,453 Dth/day is required to serve the design peak day firm customer demand in Columbia markets directly connected to Texas Eastern while 3,082 Dth/day must be delivered to TCO, as an upstream supply, to meet design day demand in Columbia markets served by TCO.

Similar to operations on Tennessee, on days when the 22,453 Dth/day delivered directly to Columbia cannot be absorbed by those markets, Columbia can divert that supply to secondary delivery points off Texas Eastern or to Texas Eastern interconnects with TCO for injection into storage or delivery to other Columbia markets served by TCO. Columbia also contracts for 10,000 Dth/day of winter season, market-area firm backhaul transportation capacity. Columbia utilizes this capacity to satisfy cold weather requirements behind the city gates connected to Texas Eastern.

Columbia contracts for 4,304 Dth/day of city gate capacity under the FTS rate schedule of National Fuel. This capacity is utilized to serve Columbia's Warren market area. In addition, Columbia also has a contract with National Fuel consisting of enhanced firm transportation ("EFT") of 4,000 Dth per day, of which 1,571 Dth per day will be received at the Mercer Interconnection and delivered to the Columbia Findlay Township meter station in Allegheny County, while 2,429 Dth per day will be

received from National Fuel's storage receipt point and delivered to the Columbia Findlay Township meter station in Allegheny County. Additionally, National Fuel will provide an enhanced storage service ("ESS") with a Maximum Storage Quantity ("MSQ") of 267,143 Dth, a Maximum Daily Injection Quantity ("MDIQ") of 1,571 Dth per day, and a Maximum Daily Withdrawal Quantity ("MDWQ") of 2,429 Dth per day to be used in combination with the EFT service.

As noted earlier, Columbia utilizes portions of its Tennessee contracts to provide supply to the National Fuel capacity. Columbia can divert the Tennessee supplies when not needed to serve National Fuel fed markets for delivery to other Columbia markets served by TCO or injection into storage.

Q. Have there been any changes to Columbia's contracts in the last year?

A. Yes, there have been a few changes to Columbia's contracts from the previous year. The Company acquired the following contract: 10,500 Dth firm transportation on TGP with a one winter only term of November 1, 2025, through March 31, 2026.

Q. Why did Columbia enter into the TGP firm transportation contract for 10,500 Dth?

A. As discussed in Revised Exhibit 5, Sheet 12, Columbia entered into a new contract to address market needs. Specifically, the 10,500 Dth on TGP was to serve the Warrendale area. This was needed to meet design day requirements in this area.

Q. Please summarize Columbia's New and Renewed Capacity process.

A. Columbia's contracts for pipeline storage and firm transportation service each contain specific provisions detailing termination dates, as well as notification dates,

wherein Columbia must notify the respective interstate pipeline if it decides to renew the capacity under current contract terms beyond the contract termination date. Approximately six to nine months prior to this notification date, Columbia determines whether this capacity or its equivalent is required to serve its residential and small commercial customers. Upon determining that the capacity is required, Columbia then determines whether this capacity is also required for system balancing or Supplier of Last Resort ("SOLR") services.

For capacity that is not required for balancing or SOLR services, Columbia prepares a Request for Proposal ("RFP") and submits the RFP to all NGSs who are licensed to conduct business on Columbia's system. This RFP defines the delivery points required by Columbia to receive gas supplies, as well as a general outline of the daily delivery volumes by point of delivery. The qualified NGSs determine if they have a desire to deliver gas supplies to Columbia at these points in the manner required by Columbia to serve its markets utilizing firm primary point capacity. If an NGS determines it has the desire and ability, then it can submit an offer under the RFP. Once received, Columbia will evaluate all offers to determine whether they meet the requirements of the RFP and, if appropriate, compare such offers against other options available to Columbia. If the offer complies with the RFP and is better than other options available to Columbia, the successful NGS and Columbia will enter into an agreement defining the delivery details required to serve the relevant market. This process of offering and accepting an offer from an NGS, along with completion of the delivery agreement, must be completed in a timely manner in order to allow

Columbia to terminate the capacity that is the subject of the RFP. In the event that no offer is received under the RFP, Columbia proceeds either to extend the contract under existing terms and rollover rights, if available, or renegotiate the contract.

Q. Did Columbia offer NGSs operating on its system an opportunity during the past year to provide new or replacement capacity under its Acquisition Process for New and Renewed Contracts?

A. Yes, Columbia provided NGSs opportunities during the past year to provide offers of replacement capacity.

Q. Please describe the capacity for which Columbia requested offers from NGSs to replace.

A. Columbia requested replacement capacity offers on capacity as follows:

1) 22,435Dth of firm transportation on Texas Eastern; and
2) 4,304 Dth of firm transportation capacity on National Fuel.

Q. Did Columbia receive any offers of replacement capacity from an NGS?

A. No.

Q. Is the capacity provided pursuant to the contracts for which Columbia requested replacement offers from NGSs required by Columbia?

A. Yes.

Q. Please describe the actions taken by Columbia to renew these contracts.

A. Columbia retained the capacity of each contract by extending the term or exercising its annual rollover rights as follows:

1) Columbia exercised its annual rollover right and retained the capacity under existing contractual provisions for the Texas Eastern contract for 22,435Dth.
2) Columbia also exercised its annual rollover right and retained the capacity under existing contractual provisions for the National Fuel contract for 4,304 Dth.

Q. Is the firm capacity listed on Exhibit TMM-2 consistent with Columbia's policy regarding the level and mix of its supply/capacity portfolio?

A. Yes, Columbia's portfolio is within the 103% policy over the five-year period. A reconciliation of Columbia's firm peak day capacity entitlement level with Columbia's future years' firm design day demand per Columbia's 2025 Design Day Forecast is provided in Company Exhibit TMM-2. The forecast also shows a maximum hourly design adjustment to the design day demand for this calculation. This adjustment is to account for the hourly flow restrictions established in EGTS's tariffs. This shows that Columbia's current peak day capacity level is 102.6%, which is within the bounds contained in Columbia's Portfolio Design policy, which provides that Columbia will have sufficient capacity to be within a range of up to 103% of the highest of its projected design day firm requirements for the five-year period of its Design Day Forecast.

Q. What has changed since last year that impacts Exhibit TMM-2?

A. Last year Exhibit TMM-2 did not include a marketed release on its TCO FT contract that had been included in previous years, which is a reduction to its capacity level. At that time, there was uncertainty with the release and there was not a clear indication

that the release would be executed going forward with the customer. Also, TCO's FERC rate case was ongoing and had proposed tariff language that would have impacted Columbia with respect to its capacity rights.

Q. Can you further explain the marketed release and how it was reflected in Revised Exhibit 5 filed in this proceeding and in Exhibit TMM-2?

A. Yes. Columbia has included a marketed release of TCO FT reflected in Revised Exhibit 5 and Exhibit TMM-2 for the amount of 2,700 Dth for 2026/27 winter and 4,000 Dth for the remaining four winters through 2030/31. This release is a net reduction to Columbia's capacity level. Subsequent to the filing last year, discussions with the customer resumed regarding continuation of a non-recallable TCO FT release and ultimately the release was executed for 4,000 Dth for the period November 1, 2025 through October 31, 2026. It is expected that this release will continue over the next five years and therefore was included in the referenced exhibits.

Q. What tariff change did TCO propose in its rate case that would have impacted Columbia's capacity rights on TCO?

A. As described in Exhibit 3 and later in my testimony, TCO filed a Section 4 rate case at FERC. Included in its filing was a proposal to implement 1/24th hourly rights on TCO's system. The proposed language in TCO's pre-filed tariff section 12.1 Maximum Daily Delivery Obligation at Delivery Points stated: "Unless otherwise specified in an applicable Service Agreement, Transporter will use 1/24th of the MDDO [Maximum Daily Delivery Obligations] for such hourly design purposes. Transporter retains the

right to restrict Shipper activity in excess of this hourly design under Section 17 of the General Terms and Conditions."

Q. Was the proposed tariff change regarding the 1/24th hourly rights approved as part of TCO's rate case?

A. No, the 1/24th hourly rights tariff change was not included in the Settlement Agreement that FERC approved on October 30, 2025. Therefore, the concerns I raised in my testimony last year regarding Columbia's ability to comply with these changes are not relevant at this time.

III. COLUMBIA'S SUPPLY

Q. Please describe how Columbia balances deliveries to all its city gates.

A. Because the majority of Columbia's customers have highly temperature sensitive demand, Columbia's supply portfolio must be able to provide widely varying daily supplies in response to daily changes in temperature.

In order to provide gas supplies on a least cost basis for its customers, Columbia relies heavily upon the daily withdrawal and injection flexibility of its primary storage service provided under TCO's FSS rate schedule. TCO's FSS rate schedule provides Columbia with its primary no-notice service. Columbia also has limited no-notice service on Texas Eastern, National Fuel and EGTS.

As noted in Exhibit TMM-1, storage service provides about 67 percent of Columbia's design peak day capacity. Storage service provides Columbia with approximately 53 percent of its normal weather, winter season supply to meet the

needs of its firm customers and the vast majority of its system balancing requirements. In addition, the flexibility of Columbia's capacity portfolio, including the storage capacity, enables it to provide EBS to GDS customers. Storage service contributes to Columbia's ability to provide a least cost gas supply under varying weather conditions. Columbia's storage capacity also provides mitigation of winter season price increases.

While Columbia relies heavily on its storage service to meet changing customer demand, Columbia's contracted storage services do not provide it with the full swing capability it requires to meet the temperature-sensitive demand swings of its customers, particularly on warmer days during shoulder months. Therefore, Columbia incorporates the use of daily spot purchases during these periods. When warranted, Columbia implements the use of "swing" provisions included in its firm gas supply contracts that provide Columbia the opportunity to reduce flowing gas supplies on these warm days yet permit Columbia to increase flowing volumes again once weather turns colder or to meet seasonal demand.

Q. Earlier in your testimony you mentioned Columbia's Elective Balancing Service. Please describe this service and its benefits.

A. EBS provides substantial enhancements to the balancing service Columbia had traditionally provided its GDS customers. EBS provides the following benefits:

1) Provides GDS customers with two balancing service options. Under Option 1, Full Balancing Services, NGSs and customers have the ability to carry banks over from month to month with several service enhancements,

which are discussed later in my testimony. Under Option 2, Monthly Cash Out, NGSs and customers choose to be cashed out monthly. A monthly cash out provides customers the opportunity to carry an intra-month bank, but this bank is cashed-out at the end of each month. There are no customers currently electing Option 2.

2) Under EBS Option 1, NGSs and customers are provided firm cold day and warm day Operational Flow Order ("OFO")/Operational Matching Order ("OMO") tolerances. Under cold day OFO/OMOs, NGS or customer deliveries equal to or greater than 95% of actual (OMO) or estimated (OFO) demand are considered to be in compliance with the flow orders, provided that the customer has sufficient gas in its bank. Under warm day OFO/OMOs, NGS or customer deliveries less than or equal to 102.5% of actual (OMO) or estimated (OFO) demand are considered to be in compliance with the flow order, provided that the customer has sufficient room in its bank to accept the over deliveries.

3) Under EBS Option 1, NGS and customer access to banks is provided on a firm basis, recognizing the daily OFO/OMO limitations noted above, as long as an NGS or customer has a positive bank balance.

Q. Please describe Columbia's capacity release program.

A. Columbia utilizes PLEXOS as its planning software. PLEXOS is used to help evaluate both short and long-term capacity release opportunities. In Columbia's evaluation of the level of capacity to release, Columbia considers the requirements of its retail

customers, including storage injection requirements. The total releasable capacity is equal to the difference between Columbia's monthly firm capacity level and the firm customer requirements at the applicable fifth design day (that capacity level which Columbia has determined may be needed for recall on up to five days in any given month). SST capacity utilized at secondary receipt and delivery points for injection into storage is also factored into the analysis. Columbia then determines the levels of recallable and non-recallable transportation capacity that is available for release. Non-recallable capacity is equal to the difference between Columbia's monthly firm entitlement level and the firm customer requirements at design day conditions. The monthly recallable capacity is then equal to the difference between the total capacity identified as releasable and the non-recallable component.

Q. Please explain the difference between recallable and non-recallable releases.

A. As the names imply, recallable releases provide the releasor with the ability to recall the capacity under the terms specified in the release agreement and in accordance with the interstate pipeline's tariff recall provisions. Non-recallable capacity releases conversely are not recallable by the releasor during the term of the release. Recallable capacity is generally less valuable to the assignee than is non-recallable capacity due to the interruptible nature of the release.

Q. How does Columbia conduct its economic analysis to develop its gas supply mix and projections of gas supply mix and cost?

A. Columbia's basic tool of analysis is the PLEXOS Gas Planning System provided by Energy Exemplar. PLEXOS determines the "optimum" time-dependent levels of pipeline transportation service and storage service to be utilized to meet Columbia's prospective demand under various weather-related scenarios and recognizes specific demand regions within Columbia's service territory and the pipeline capacity and supply sources that are available to each region. Columbia updates supply prices, storage balances and other input data in PLEXOS on an ongoing basis from a variety of published and private sources. Columbia utilizes PLEXOS for both long-range and short-term operational planning.

Q. In calculating the least cost gas supply analysis, what price information is considered by the model?

A. Columbia prepares a monthly estimate of gas prices for use in its monthly planning process. The estimate generally reflects NYMEX prices but may be adjusted to reflect current knowledge of gas pricing trends. It is recognized that the natural gas futures prices traded daily in the commodity market fluctuate widely in response to technical analyses by traders, daily business news and the weather. Nonetheless, the NYMEX price represents the price that industry participants are willing to offer for gas at a given point in time.

In addition to the projected cost of gas, Columbia incorporates demand and commodity transportation costs of all pipelines operating in its service territory.

Columbia's goal in estimating prices is to project, as accurately as possible, the cost of supply to the Company at the city gate. The PLEXOS model utilizes the

monthly estimate of gas prices and transportation fuel and commodity costs to develop city gate rates and a least cost plan for purchasing gas supplies.

Q. Earlier you mentioned the monthly planning process. Can you please elaborate?

A. The monthly planning process is utilized to determine how Columbia should manage its gas supply activity each month to minimize gas costs for its customers while maintaining system reliability. On a monthly basis, Columbia updates its projection of future gas prices over the near term and incorporates additional information, including storage levels and reliability considerations, into the PLEXOS model. Columbia then conducts analyses utilizing the PLEXOS model, incorporating customer demand levels, transportation capacity and gas prices to determine the level of flowing supplies and storage activity that will minimize gas supply costs while maintaining safe, reliable service. The monthly planning analysis helps identify term and spot market purchase requirements, swing gas requirements, capacity release and off-system sales opportunities, and operational targets for storage. Upon completion of the monthly planning analysis, Columbia conducts an internal meeting, where the results of the analysis are presented and discussed, and a purchasing strategy is developed for the forthcoming month. The analysis is conducted before the beginning of each month and can be adjusted during the month as conditions dictate.

IV. COLUMBIA'S CHOICE℠ PROGRAM

Q. Please describe briefly Columbia's Customer CHOICE℠ program.

A. Under the Customer CHOICE℠ program, NGSs are required to deliver gas supplies to Columbia at a constant daily quantity each day of the year. Columbia remains the SOLR and provides needed balancing services to match supply and demand for all customers.

Q. Please elaborate on the NGSs' delivery obligations under Columbia's Customer CHOICE℠ program.

A. Columbia's Customer CHOICE℠ program requires NGSs to deliver to Columbia's city gates, on a firm basis, an equal amount of gas every day of the year to satisfy their customers' annual gas requirements. Each month Columbia determines the normalized annual consumption for each NGS customer aggregation group. This volume is then divided by 365 to yield the volume of natural gas each NGS is required to deliver to Columbia for each of its aggregation groups each day of the month. Customer consumption above or below the normalized annual volumes are reconciled to the NGS's actual deliveries annually.

Q. Please describe the aggregation groups and their purpose.

A. Aggregation groups allow NGSs to aggregate similarly situated customers, located within a given geographical area, for purposes of nominating and scheduling gas supplies to Columbia. Aggregations provide the NGS with the ability to combine customers so that the imbalances between supply and demand for multiple customers are netted together instead of requiring balancing for individual

customers. The netting reduces the administrative requirements for both Columbia and the NGS. Aggregation groups also enable Columbia to manage the receipts of natural gas on its system when and where needed to ensure system reliability and therefore, satisfy the requirements of its customers.

Q. Does Columbia anticipate any changes to this process?

A. Not at this time.

Q. May NGSs have more than one aggregation group?

A. Yes. Columbia requires each NGS to have a minimum of one aggregation group for all its customers located within the geographic boundaries of each TCO specified Market Area. These Market Areas are established by TCO to facilitate the operational needs of its transmission system. Aligning the aggregation groups to these Market Areas is one means of assuring safe and reliable service.

Q. How do NGSs acquire firm capacity to participate in Columbia's Customer CHOICE[SM] program?

A. Columbia's Customer CHOICE[SM] program operates as a mandatory capacity assignment program, with one exception. The program allows NGSs participating in the CHOICE[SM] program the opportunity to provide Other Primary FTS capacity should Columbia have a projected design day capacity deficiency. Each year, Columbia determines if its contracted capacity is sufficient to meet its projected design day demand. In the event it is not, Columbia will provide CHOICE[SM] participating NGSs the opportunity to provide Other Primary FTS capacity that the NGS may utilize to provide supplies for its CHOICE[SM] program customers. To the

extent CHOICE[SM] NGSs are able to provide Other Primary FTS, which has primary delivery point entitlements at a Columbia city gate, the NGS will be permitted to utilize that capacity in lieu of mandatory assignment from Columbia of a like volume. The volume of Other Primary FTS that CHOICE[SM] NGSs may provide under this program is limited to any deficiency that Columbia may project for the forthcoming year. To the extent that an NGS is unable to provide Other Primary FTS that is acceptable to Columbia, the NGS must take mandatory assignment of FTS capacity from Columbia. Because Columbia does not currently have a projected design day capacity deficiency, NGSs are not permitted to provide Other Primary FTS capacity.

Q. Who is responsible for the payment of demand costs when the capacity is assigned to the NGS by Columbia?

A. As with other capacity release transactions, the assignee, or the NGS in this instance, has the responsibility to pay the pipelines directly for the assigned capacity. However, Columbia remains ultimately liable for charges in the event of non-payment of released capacity costs by the assignee.

Q. Does Columbia retain any capacity to provide service to the CHOICE[SM] program customers?

A. Yes, Columbia retains firm contract rights to all storage, other upstream pipeline and peaking capacity, if any.

Q. Who pays for the costs of this retained capacity?

A. The customers participating in the Customer CHOICE[SM] program pay the costs of this retained capacity. Columbia charges the participating customers a rate per unit

of throughput to recover the costs Columbia incurs. This rate is equal to the Purchased Gas Demand Cost ("PGDC") charge in Columbia's sales tariff less the costs of assigned EGTS and TCO capacity, adjusted for storage injection and withdrawal charges. This calculation assures that sales and CHOICE[SM] customers are paying the same amount for capacity.

Q. Please describe Columbia's obligations as a SOLR.

A. In general, the SOLR retains the responsibility to maintain safe and reliable service and ensure that adequate supplies are available to satisfy daily, seasonal and annual requirements for residential, small commercial, small industrial, other essential human needs customers and any other customer class determined by the Commission to fall within the SOLR function. Included in the SOLR function are sales to customers that have not chosen an alternate supplier, choose to be served by the SOLR, or are refused service by NGSs. The SOLR also provides supplies for customers whose NGS fails to deliver their requirements.

Q. Please describe how Columbia, as SOLR, maintains safe and reliable service.

A. Consistent with its role as a public utility, Columbia maintains safe and reliable service by providing those services it is uniquely qualified to provide and manage. These include:

1) management of distribution system up to the point where customers take delivery;
2) determination of customer requirements;

3) management of city gate requirements; and

4) assuring that adequate capacity is available in the long-term to satisfy the requirements of its residential customers and the human need requirements of its small commercial and industrial customers even under extreme (design) conditions.

Item (4) is closely aligned with Columbia's long-range planning efforts in assuring that adequate supplies and capacity are available to human needs customers as well as those other customers that contract for firm services from Columbia.

Q. Please describe Columbia's SOLR function as it pertains to the distribution system.

A. Columbia's SOLR responsibilities in this area include: (a) field management of maintenance, customer service, regulation and measurement; (b) gas control operations; (c) management of any on-system storage, peaking or other supply related assets; and (d) determination of maximum daily delivery obligations ("MDDO") and pressure requirements at each point of delivery ("POD") with interstate pipelines.

Q. What SOLR responsibilities are incorporated in the determination of customer requirements?

A. SOLR responsibilities in this area include calculation of annual customer requirements and associated daily NGS deliveries, establishment of design day criteria and determination of firm and non-firm design day requirements.

Q. What are Columbia's SOLR obligations related to the management of city gate requirements?

A. The responsibilities related to management of city gate requirements include: (a) provision of no-notice city gate balancing to accommodate differences between supplier deliveries and customer demand, including GDS customers; (b) management of the annual true-up process; (c) evaluation of NGS requests for utilization of alternate delivery points; (d) maintenance of a no-notice back-up supply in the event of an NGS failure; (e) development and administration of a plan for dealing with an NGS failure; (f) development and maintenance of effective on-system nominations systems; and (g) development and enforcement of supply reliability requirements, including implementation of OFO/OMOs and other system management tools provided for in the tariff.

Q. What SOLR responsibilities are included in assuring that long-term capacities are available for human needs customers?

A. Reliability of service to human needs customers requires that access to firm capacity be without question. In today's energy environment, that assurance is only accomplished through the maintenance of long-term capacity assets that do not disappear because of an election of a supplier to exit the business, bankruptcy or more favorable economic options serving other segments of the natural gas marketplace. These human needs customers do not have a choice in the utilization of natural gas. They need it for the essential life sustaining uses of heating their homes and cooking their meals. The maintenance of firm capacity on an unquestioned basis

is essential in assuring reliable service. This long-range process ensures that adequate pipeline capacity is available to satisfy customer requirements and that adequate contractual commitments exist at each Point of Delivery ("POD") to satisfy MDDO and pressure obligations. Also, active participation in FERC activities is a key part of the process.

Q. What gas supply and capacity resources does Columbia utilize to provide these SOLR functions?

A. Columbia will continue to utilize those assets presently under its control that are not assigned to NGSs under its Customer CHOICE[SM] program. Included are capacity assets Columbia will require to maintain balancing services and/or system integrity for service to its customers. These are principally storage and storage-related transportation capacities. Additionally, all capacity assignments made to NGSs participating in Columbia's Customer CHOICE[SM] program will be made on a recallable basis. If an NGS who has been assigned capacity fails to deliver supplies to Columbia in a manner consistent with Columbia's tariff, Columbia will recall this capacity, as needed, to maintain service to affected customers. While it is possible that Columbia may experience a delay in recalling capacity assigned to an NGS and filling that capacity with back up supplies, Columbia will be able to continue to provide adequate supplies to its customers from its retained storage on all but extremely cold days. Columbia's tariff also requires that any NGS that provides capacity under Columbia's Acquisition Process for New and Renewed Contracts and later leaves the Customer CHOICE[SM] program must provide for that capacity to be

assignable to Columbia until such time as Columbia is able to acquire equivalent replacement capacity.

Q. Has Columbia made any exchange, capacity release or off-system sales transactions with affiliates?

A. No, as denoted in Revised Exhibit 5, Sheet 20, Columbia did not enter into any of these transactions with an affiliate for the period under review.

V. COLUMBIA'S ACTIVITIES AT FERC

Q. Was Columbia active in any FERC proceedings during the last year?

A. Yes, as shown in Company Exhibit 3, either directly, as part of the Columbia Distribution Companies, or through its memberships in industry trade associations like the American Gas Association ("AGA"), Columbia was active at FERC in regulatory proceedings, rulemakings and policy formulation that had the potential to impact services and/or costs to Columbia and its customers.

Q. Generally, how has Columbia represented the interests of its customers by participating in each of the listed proceedings?

A. First, Columbia reviews all relevant FERC notices of rate, certificate and rulemaking proceedings through a monitoring network on FERC's website. Further, Columbia, as a customer of various pipelines, receives notices of rate and proposed tariff changes as filed. Finally, Columbia makes every effort to conduct various forms of informal communication with its pipeline suppliers, peer customers of those pipelines and respective interested state agencies to keep apprised of upcoming

proposals, expected tariff filings, and any other federally regulated activities.

Second, a preliminary analysis of notices and filings is completed by Columbia's Energy Supply and Optimization ("ES&O") personnel for discussion with Legal and Regulatory personnel. Based on those discussions, a determination is made about whether to intervene. If a determination is made to intervene, then intervention points are developed. A decision to become an active participant in a proceeding protects Columbia's right to address the elements of a filing that are significant to Columbia. Being an active participant ensures that Columbia is advised of all pre-hearing, technical and settlement conferences and hearings convened in a case, as well as the comments and interventions of other parties.

Analyses of those filings in which Columbia has intervened is conducted on an ongoing basis. The potential impact of rate and policy changes is determined. From these analyses, Columbia reasonably formulates positions that best represent the interests of Columbia and its customers and recommends a level of involvement that is necessary to advocate those positions. Columbia pursues those positions through the legal process, by filing comments and/or testimony on its own when appropriate, through trade or customer groups, through participation in technical conferences and/or through negotiations within the settlement process.

As indicated earlier, Columbia is also a member of the AGA, a natural gas industry trade group that participates actively in select proceedings on behalf of its local distribution company members.

As demonstrated in Company Exhibit 3, Columbia was an active party to

numerous FERC proceedings in calendar year 2025. Columbia has been similarly active in the first quarter of 2026. Many more pipeline filings and proposals that Columbia reviewed during that time are also listed, but Columbia only became a party in those cases where it determined that there was the potential for impact on it or its customers.

Q. Please summarize Columbia's FERC activities throughout the past year.

A. During 2025, Columbia paid particular attention to the impact of rate filings by pipelines that proposed adjustments to tariff rates. Columbia's activities can be summarized as follows:

1) reviewing all FERC filings by all pipelines that provide natural gas transportation services to Columbia;
2) intervening in and following all FERC dockets having potential ramifications to Columbia;
3) participating in all major proceedings in which tariff changes and/or reliability issues affecting Columbia's customers were scheduled to be discussed (this included attending technical conferences and settlement conferences hosted by the FERC and the pipelines); and
4) on September 30, 2024, TCO filed a revised tariff record that supports a system-wide general increase in TCO's rates, and includes changes to TCO's rates, rate schedules, and General Terms and Conditions ("GT&C"), effective April 1, 2025 (RP24-1103). The Company filed protest intervention on October 15, 2024. The Company also joined an LDC Customer Group to

increase leverage for an equitable settlement. FERC approved rates and suspended the tariff records and rates until April 1, 2025. Effective April 1, 2025, TCO will implement these rates and tariff changes subject to refund. Settlement conferences took place from November 2024 to June 2025. In July 2025, TCO filed interim settlement rates to be effective June 1, 2025. August 13, 2025, TCO submitted the Stipulation and Agreement of Settlement which resolved all issues in the general rate case. The Commission gave final approval on the uncontested Settlement on October 30, 2025.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT TMM-1

Columbia Gas of Pennsylvania, Inc
Firm Peak Day and Annual Entitlements
Contract Year 2026-27

Supply Source	Peak Day Entitlements Daily (MDth/Day)	Peak Day Entitlements Percentage (%)	Annual Entitlements [1] Annual (MDth/Yr)	Annual Entitlements [1] Percentage (%)
Storage				
TCO FSS	395.7	60%	21,522	20%
EGTS GSS[2]	25.6	4%	1,839	2%
Equitrans 115SS[3]	9.6	1%	495	0%
National Fuel	2.4	0%	264	0%
Total Storage	433.3	66%	24,120	23%
Firm Transportation (City Gate)				
TCO Net of Marketed Release	132.2	20%	48,264	46%
Eastern Gas Transmission	5.3	1%	1,918	2%
Tennessee Gas Pipeline	19.3	3%	7,043	7%
Texas Eastern Transmission	22.5	3%	8,195	8%
Equitrans	35.9	5%	13,093	12%
National Fuel FTS	5.8	1%	2,123	2%
Total City Gate FTS	220.9	34%	80,636	77%
Local Production				
Direct into CPA	0.7	0%	256	0%
TOTAL CITY GATE SUPPLY	654.9	100%	105,012	100%
Firm Transportation (Upstream)				
Tennessee	4.3	--	--	--
Texas Eastern	3.1	--	--	--
Total	7.4	--	--	--

[1] Includes seasonal storage entitlements. Equitrans seasonal entitlements of 1,500 MDth and Eastern Gas Transmission seasonal entitlements of 240 MDth are dedicated to Enhanced Balancing Service (EBS) Option 1 provided to General Distribution Service (GDS) customers, and are excluded from this Exhibit.

[2] For contract year 2026-27, 3.198 MDth of the winter season firm transportation capacity will be charged to and utilized in the provision of EBS Option 1.

[3] For contract year 2026-27, 9.559 MDth of the winter season firm transportation capacity will be charged to and utilized in the provision of EBS Option 1.

EXHIBIT TMM-2

Columbia Gas of Pennsylvania, Inc
Firm Peak Day Supplies vs Firm Demand
(MDth/Day)

Contract Year	**2026/27**	**2027/28**	**2028/29**	**2029/30**
Supply Source				
Storage				
TCO FSS	395.7	395.7	395.7	395.7
EGTS GSS[1]	28.8	28.8	28.8	28.8
EGTS GSS[1] Max Hour adjustment	5.2	5.2	5.2	5.2
Equitrans 115SS	19.1	19.1	19.1	19.1
National Fuel	2.4	2.4	2.4	2.4
Total Storage	451.3	451.3	451.3	451.3
Firm Transportation (City Gate)				
TCO net of Marketed Releases	132.2	130.9	130.9	130.9
Eastern Gas Transmission[1]	5.3	5.3	5.3	5.3
Tennessee Gas Pipeline	19.3	19.3	19.3	19.3
Texas Eastern Transmission	22.5	22.5	22.5	22.5
Texas Eastern Transmission A2M3 Preced	0.0	3.0	5.0	5.0
Equitrans	35.9	35.9	35.9	35.9
National Fuel FTS	5.8	5.8	5.8	5.8
Total City Gate FTS	220.9	222.6	224.6	224.6
Local Production				
Direct into CPA	0.7	0.7	0.7	0.7
TOTAL CITY GATE SUPPLY	672.9	674.6	676.6	676.6
Less Capacity to provide Standby	5.8	5.8	5.8	5.8
Less Capacity to provide EBS	12.8	12.8	12.8	12.8
Net Capacity	654.3	656.0	658.0	658.0
2025 DDF FIRM REQUIREMENT	628.0	629.9	632.0	633.8
Max Hour Adjustment	7.5	7.5	7.6	7.6
Adjusted 2025 DDF Firm Requirement	635.5	637.4	639.6	641.4
DIFFERENCE	18.8	18.6	18.4	16.6
% OF DEMAND	3.0%	2.9%	2.9%	2.6%
2025 DDF FIRM REQUIREMENT plus 3%	654.6	656.6	658.8	660.6
DIFFERENCE	(0.3)	(0.6)	(0.8)	(2.6)
% OF DEMAND	0.0%	-0.1%	-0.1%	-0.4%

[1] Eastern Gas Transmission (EGTS) formerly Dominion Transmission (DTI)

§53.64(c)(6) Each Section1307(f) utility shall file with the Commission a statement of its current fuel procurement practices, detailed information concerning the staffing and expertise of its fuel procurement personnel, a discussion of its methodology for obtaining a least cost and reliable source of gas supply, including a discussion of any methodologies, assumptions, models or rules of thumb employed in selecting its gas supply, transportation and storage mix, its loss prevention strategy in the event of fraud, nonperformance or interruption of performance, its participation in capacity release and reallocation programs, the impact, if any, upon least cost fuel procurement by constraints imposed by local transportation end users, interruptible service, balancing, storage and dispatching options, and its strategy for improving its fuel procurement practices in the future and timetable for implementing these changes.

Response:

OVERVIEW

Columbia Gas of Pennsylvania, Inc.'s ("CPA") supply objective is to secure and deliver competitively priced, reliable gas supplies to meet its customers' demand at least cost. CPA utilizes its portfolio of firm transportation and storage capacities on interstate pipelines and its portfolio of term and spot market supplies to achieve this objective.

As both a merchant provider of gas and a distributor of customer-owned gas, CPA has the responsibility to balance the supply and demand for all customers at the city gate on all days, including both design cold days when demand is at peak high levels and warm days when demand is at minimal levels. CPA incorporates this daily balancing requirement into its planning process, relying upon the injection and withdrawal capabilities of its contracted storage services and the negotiated flexibility in some supply contracts to provide for the daily swings in customer demand.

Within its Energy Supply and Optimization ("ES&O") Department, CPA determines what supply and capacity contracts, and contract volumes are necessary for the long term to minimize gas supply and capacity costs, giving consideration to such factors as reliability, flexibility, diversification and the likelihood of various price and demand forecasts. ES&O's Planning section is responsible for determining the appropriate components of CPA's capacity portfolio and performing strategic supply planning functions. Planning utilizes the PLEXOS® Software as its primary planning tool.

PLEXOS® is used to determine the volumes of flowing supplies and storage withdrawals/injections which will minimize gas supply commodity costs while preserving reliability. Results of CPA's PLEXOS® driven planning efforts are utilized to guide the purchasing of gas supplies and contracting for the necessary pipeline capacity.

On a day-to-day basis, ES&O determines CPA's expected system-wide demand and the supply required from all supply contracts and storage to meet customer demand. Further, ES&O is responsible for ensuring that deliveries to Pipeline Scheduling Points ("PSPs") are within applicable contract entitlement levels and comply with any pipeline operational notices. Collectively, the ES&O and the Customer Programs and Billing Departments determine when actions are required of CPA's transportation and CHOICE℠ customers to maintain system integrity. CPA seeks to invoke such actions by issuing Operational Flow Orders ("OFOs"), Operational Matching Orders ("OMOs") and/or Seasonal Flow Orders ("SFOs"). CPA attempts to precede any such order with an Operational Alert ("OA") or Emergency Alert ("EA").

Information generated within ES&O is used to guide CPA's term contracting and spot market purchasing practices, the release and recall of capacity, and the determination of operational storage targets, storage management and off-system sales. ES&O manages CPA's term, spot market and peaking supplies and is responsible for CPA's off-system sales transactions. ES&O nominates and schedules all volumes on upstream interstate pipelines, manages CPA's capacity release program, including releases to Natural Gas Suppliers ("NGSs") under CPA's CHOICE℠ program and uses its transactional information to reconcile all supply and capacity invoices from suppliers, and to generate off system sales invoices.

The Nominations section within Customer Programs and Billing manages General Distribution Service ("GDS") customer and CHOICE℠ supplier daily nominations, confirming supplies and allocating volumes to customers for billing and operations. CPA utilizes the daily GDS and CHOICE℠ volume information as an input in planning and managing its own supply and storage activity.

The remainder of this exhibit is comprised of the following sections:

- Demand, which includes discussions on annual, seasonal and peak day demands;
- PLEXOS® Optimization Model;
- Capacity;
- Operation of Storage;
- Supply Contracts and Daily Balancing;
- Services for CHOICE℠ Customers;
- Federal Regulatory Activities; and
- Off-system Sales and Capacity Release Incentive Program.

DEMAND

Monthly and Seasonal Demand: Three Weather Scenarios

The first step in CPA's gas supply process is the determination of customers' energy needs. Projected customer demand is based upon weather-normalized historical consumption adjusted to reflect factors such as conservation, appliance efficiency improvements and customer additions and deletions. The net result is a projection of monthly demand that CPA uses for planning purposes. CPA projects demand and supply purchase requirements for its remaining Sales Service customers, provides daily balancing for the demands of its Customer CHOICE℠ customers, and makes contingency plans for a range of firm customer demand driven by varying weather conditions and the possible failure of a CHOICE℠ NGS's supply. Finally, CPA provides Standby Service under Rate SS to those GDS customers that contract for it, and Elective Balancing Services ("EBS") for all GDS customers. Under EBS, GDS customers choose one of two options: Option 1 - Full Balancing Service (ability to carry a positive bank from month to month); or Option 2 - Monthly Cash out (Intra-month Banking Service). EBS gives GDS customers flexibility in managing their supply and demand. The demand of CPA's Sales Service and CHOICE℠ Service customers is highly weather sensitive with approximately 75 percent of normal weather annual demand occurring during the winter. CPA defines the winter season as the months of November through March and the summer season as the months of April through October.

CPA considers three design weather scenarios in the development of its least cost supply plan: 1 in 10 colder, normal and 1 in 10 warmer. These scenarios are developed to capture the uncertainties related to winter demand. For the summer, CPA develops only a normal weather demand scenario. CPA combines the three winter scenarios with the summer scenario to determine three contract year scenarios.

The normal weather scenario provides a forecast based upon the 20-year average of degree days for the full year.

The colder weather scenario reflects an increase in total winter season degree days based on a 1 in 10 or 10 percent variance for winter season degree days. The 10 percent variance for the colder weather scenario means that there is a 10 percent probability that the winter will have more degree days than the planned colder scenario.

The warmer weather scenario is based upon a 1 in 10 or 10 percent variance. The 10 percent variance for the warmer weather scenario means there is a 10 percent probability that the winter season will have fewer degree days than the planned warmer scenario. Table

1 presents the demand forecasts for the three weather scenarios. For purposes of the requirements projection in this filing, CPA utilizes the normal weather demand forecast.

Table 1. Projected customer demand for the colder, normal and warmer weather scenarios. The projected customer demand excludes standby volumes.

Projected Customer Demand for Weather Scenarios
October 2025 – September 2026 (Mdth)

	Colder	Normal	Warmer
Sales Excluding CHOICE℠ :			
Residential	29,054	27,158	25,262
Commercial	9,422	8,807	8,192
Industrial	289	273	258
Other	574	574	574
Subtotal	39,339	36,813	34,286
CHOICE℠	10,340	9,677	9,014
Total	49,679	46,490	43,300

As noted from Table 1, CPA's projected Sales and CHOICE℠ customer demand varies by about 6.4 MMDth between the Colder and Warmer weather scenarios. CPA's supply portfolio is designed to enable CPA to deliver supplies reliably to its customers while minimizing the cost to serve this uncertain demand.

Design Weather Conditions.

On all days, including days of peak demand, CPA must be ready to serve the demand of Sales Service customers and to provide balancing for CHOICE℠ Service customers. Therefore, to ensure reliability, CPA has established design parameters for estimating Sales Service and CHOICE℠ Service customer demand under extreme weather conditions. CPA's Design Day Forecast is based on Design Day conditions consisting of:

- Current Day Design Temperature;
- Prior Day Design Temperature;
- Current Day Design Wind Speed; and
- Occurrence on a Weekday.

CPA updates the design conditions approximately every five to ten years. The most recent update was in 2025 and the 2025 Design Day Forecast incorporates the results. CPA determines the Design Day conditions by weather station, and then determines pipeline scheduling point and company-wide design conditions by weighting.

To determine the Current Day Design Temperature for a weather station, CPA fits a Gumbel probability distribution to the collection of minimum daily temperatures for each winter season, one daily temperature per season. The Gumbel probability distribution is used because the distribution of historical temperatures is skewed. CPA fits a probability distribution to the historical daily temperatures so that it can estimate the future risk of the occurrence of any temperature. With CPA's Design Day Risk Criteria of 1 in 15, the probability is 6.67 percent that any winter will have one or more days with an average daily temperature equal to or colder than the Current Day Design Temperature. The associated company-wide Current Day Design Temperature of -5° Fahrenheit has occurred or been exceeded on five occasions since the winter of 1949/50. The latest was January 19, 1994 when the average temperature was -6° Fahrenheit. Within this time period, CPA's coldest average daily temperature of -8° Fahrenheit was recorded on two occasions; January 17, 1982 and January 18, 1994.

The Prior Day Design Temperature is determined from the mean temperature difference between historical cold days and their associated prior days. Cold days, for the purpose of determining the Prior Day Design Temperature, are defined as those which are no warmer than the Current Day Design Temperature plus 5° Fahrenheit.

Current Day Design Wind Speed is based on an analysis of wind activity for the 1991/92 through 2024/25 winters. This analysis determines the average wind speed on cold days, where cold days are defined as days that are no warmer than the Current Day Design Temperature plus 15° Fahrenheit.

Design Day Demand and Date

CPA utilizes multivariable linear regression analysis to determine Design Day Demand. CPA's methodology is discussed in its 2025 Design Day Forecast, which is included in this filing as Exhibit No. 13. Table 1 shows the 2025 Design Day Forecast for the 2026-2027 winter season. As shown, a large majority, approximately 76 percent or 628 MDth/day, of CPA's Design Day requirements are for Sales Service and CHOICE℠ Service customers. CPA contracts for firm capacity for these customers.

Table 2. Presents the Design Day Demand forecast for the winter season 2026-27. The Design Day Demand excludes standby and EBS volumes.

Winter Season 2026-27 Design Day Demand (MDth/Day)

	Sales and CHOICE℠	GDS	Total
Residential	452.4	0	452.4
Commercial	171.6	97.2	268.8
Industrial	2.0	98.9	100.9
Other	2.1	0	2.1
Total:			
Volume	628.1	196.1	824.1
Percent	76 percent	24 percent	100 percent

For capacity planning purposes CPA forecasts Design Day Demand for five years into the future. This projection incorporates the projected purchased gas cost ("PGC") rate and associated retail rates in November, and the customers' sensitivity to price. Analysis indicates that high retail gas rates at the beginning of the winter correlate with increased customer conservation.

Table 3. Presents the Design Day Demand forecasted for the winter seasons 2026-2027 and 2027-2028. The Design Day Demand excludes standby and EBS volumes.

Winter Season 2026-2027 and 2027-2028 Design Day Demand (MDth/Day)

	Sales and CHOICE℠	GDS	Total
2026 – 2027	628.1	196.1	824.1
2027 – 2028	629.9	197.5	827.4

Daily deliverability from CPA's contracted pipeline storage services declines during the winter season as storage inventory is withdrawn. To help ensure reliability on late winter days, CPA determines a Design Date of Occurrence for the Design Day. For its portfolio design, CPA determines, with 10 percent risk, the latest date within a winter season of a design temperature or colder occurring for the CPA service area. Since there are only a few historical observations in this analysis, CPA uses a "t - distribution" to calculate the Design Date, January 25**.**

Maximum and Minimum Daily Demands by Month

In addition to the Design Day Conditions for the winter season, CPA has established Winter Monthly Cold Conditions for Long Range Planning, a period of five years into the future. A capacity portfolio must enable CPA to serve customer demand throughout the winter, including the monthly design days.

For each month, CPA analyzed temperatures since 1949 to determine the coldest daily temperature with 1 in 10, or 10 percent risk level. That is, for each month, the probability is 10 percent that the month will have one or more days with an average temperature equal to or colder than the Winter Monthly Cold Design Temperature.

Winter Monthly Cold Design Conditions enable CPA to plan for extreme demands that may occur within any winter month. CPA utilizes coefficients developed from monthly multivariable linear regression models to estimate the firm and total customer demand for the Winter Monthly Cold Design Temperatures.

The estimates of monthly maximum demands help CPA to develop its least cost supply plan by providing adequate supply in the event of late winter cold temperatures while concurrently helping to establish levels of recallable and non-recallable capacity release volumes.

CPA also estimates the minimum daily demand for each month that would occur under warm conditions. The minimum daily demand for each month is based on an analysis of the daily demands that have occurred during that month over the most recent five years of history. The estimated minimum daily demand for each month is calculated based on a normal distribution fit to the daily demands, and a 10 percent probability of occurrence.

PLEXOS® OPTIMIZATION MODEL

To reflect the constraints in pipelines' tariffs and to ensure optimum use of its supply contracts and pipeline entitlements, CPA uses the PLEXOS® Software, provided by Energy Exemplar, as its primary tool for supply planning. CPA purchased the PLEXOS® Software in conjunction with its affiliated Columbia Distribution companies. Through this association CPA is permitted full use of the PLEXOS® model while incurring a portion of the maintenance fee.

PLEXOS® is a PC based decision support modeling system, which uses linear programming, a mathematical “global optimization" method, to determine the least cost gas supply. PLEXOS® provides a solution to the problem of choosing and scheduling gas supply quantities to flow time-dependently through a gas supply and transportation/storage network. CPA uses PLEXOS® to model geographic demand regions and their operational

gas flow limitations. PLEXOS® measures CPA's ability to balance supply and demand under colder, normal, and warmer weather scenarios.

CPA utilizes the PLEXOS® model for two primary purposes: (1) Long-Term Planning and (2) Operational Planning.

Long-Term Planning generally covers a time horizon of five years. Long-term planning includes analysis of capacity portfolio options, and projections of gas supply costs. The goal of the PLEXOS® analysis is to minimize total costs including the capacity costs and the variable operating costs while maintaining reliability.

Operational Planning incorporates existing market conditions to determine an optimum plan for utilization of available supplies and capacity over the short term, up to 12 months. CPA develops a short-term supply plan on a monthly basis utilizing PLEXOS®, with more frequent updates as needed. These plans incorporate all of the storage constraints discussed later in this exhibit and are used to determine purchases, capacity use and storage utilization. In the short term, both capacity and the capacity costs are generally fixed, so the goal of this PLEXOS® analysis is to minimize the variable operating (commodity) costs. Costs taken into account in this process include:

- supply contract commodity costs;
- transportation commodity costs to the city gate;
- storage injection costs;
- storage withdrawal costs; and
- fuel.

Total system variable operating cost is minimized subject to various physical and contractual constraints, including:

- the daily flow restrictions on system components;
- pipeline transportation capacities; maximum storage injection and withdrawal rates;
- Storage inventory limits and ending target levels.

CAPACITY

Capacity Portfolio

As stated at the outset of this exhibit, CPA's supply objective is to secure and deliver competitively price, reliable gas supplies. To assure reliability, CPA uses firm capacity in its gas supply plan to serve Design Day Demand.

Table 4. Details CPA's projected Design Day Demand based on CPA's 2024 DDF and firm capacity for the next four winter seasons.

Table 4
Columbia Gas of Pennsylvania
Firm Peak Day Capacity and Demand (MDth/Day)

	Contract Year			
	2026-27	**2027-28**	**2028-29**	**2029-30**
Demand of Sales and Choice Customers				
Residential	452.4	453.9	455.5	457.0
Commercial	171.5	171.9	172.4	172.7
Industrial	2.0	2.0	2.0	2.0
Other	2.1	2.1	2.1	2.1
Total	628.0	629.9	632.0	633.8
Max Hour Adjustment	7.5	7.5	7.6	7.6
Total Demand	**635.5**	**637.4**	**639.6**	**641.4**
Capacity				
Firm Transportation				
TCO	134.9	134.9	134.9	134.9
Less Marketed Capacity Releases	(2.7)	(4.0)	(4.0)	(4.0)
Net TCO	132.2	130.9	130.9	130.9
EGTS	5.3	5.3	5.3	5.3
Equitrans	35.9	35.9	35.9	35.9
Tennessee Gas Pipeline	19.3	19.3	19.3	19.3
Texas Eastern Transmission	22.5	22.5	22.5	22.5
Texas Eastern Transmission A2M3 (precedent)	0.0	3.0	5.0	5.0
National Fuel Gas Supply Corp.	5.8	5.8	5.8	5.8
Subtotal, net of releases	220.9	222.6	224.6	224.6
Firm Storage				
EGTS GSS	28.8	28.8	28.8	28.8
EGTS GSS Max Hour adjustment	5.2	5.2	5.2	5.2
TCO FSS	395.7	395.7	395.7	395.7
Equitrans	19.1	19.1	19.1	19.1

National Fuel		2.4	2.4	2.4	2.4
	Total	451.3	451.3	451.3	451.3
Local Direct		0.7	0.7	0.7	0.7
Total Firm Capacity					
Gross		672.9	674.6	676.6	676.6
	Less Capacity to provide Standby	(5.8)	(5.8)	(5.8)	(5.8)
	Less Capacity to provide EBS	(12.8)	(12.8)	(12.8)	(12.8)
	Net Capacity	**654.3**	**656.0**	**658.0**	**658.0**
Difference: Capacity less Demand		18.8	18.6	18.4	16.6

Firm Peak Day Capacity and Demand (MDth/Day)

CPA's available capacity is approximately 102.6 percent of projected firm demand adjusted for a maximum hour design for contract year 2029-30, the highest projected design day firm requirements in CPA's 2025 Design Day Forecast. CPA is subject to hourly flow restrictions on EGTS pipeline and needs to hold enough capacity to meet the hourly restriction. Failure to comply with EGTS' hourly flow restrictions could lead to assessment of penalties and potential system reliability issues. Therefore, the design day requirements have been adjusted to reflect the additional maximum hour requirement. The variance is within the bounds contained in CPA's Portfolio Design policy which provides that CPA will have sufficient capacity to be within a range of up to 103 percent of the highest of its projected design day firm requirements for the five-year period of its Design Day Forecast. Continuation of CPA's Portfolio Design policy was a part of the July 1, 2013 Joint Petition for Settlement ("The Settlement") of the Rate Investigation Pursuant to 66 Pa.C.S § 1307(f), which was approved by order adopted August 15, 2013 at Docket Nos. R-2013-2351073, C-2013-2354079 and C-2013-2354106.

Table 4 shows that CPA's capacity portfolio contains a substantial amount of storage. Storage capacity enables CPA to purchase a majority of its annual customer requirements during the seven summer months. Some of the summer purchase volume is used to serve current customer demand, while storing most of the volume to serve customer demand the following winter. Since CPA uses FTS to fill storage in the summer and to serve current demand in the winter, the annual FTS capacity utilization factor is relatively high.

TCO provides approximately 66 percent of CPA's winter season demand and about 81 percent of CPA's Design Day capacity. TCO is an unaffiliated interstate pipeline. CPA's

service territory lies in eight TCO PSPs, contained within two TCO Operating Areas. Each PSP is synonymous with a single or group of geographically related delivery points to CPA's distribution system otherwise known as a Master List of Interconnections ("MLI").

The vast majority of CPA's TCO capacity also has grandfathered Maximum Daily Delivery Obligation ("MDDO") and Daily Delivery Quantity ("DDQ") rights. These grandfathered MDDO and DDQ rights provide CPA the necessary flexibility to receive varying volumes at each of its approximately 300 individual receipt points from TCO each day. This flexibility and associated benefits are derived from the grandfathered MDDOs and DDQs under this contract that exceed the contract Total Firm Entitlement ("TFE"). As a consequence, TCO is obligated to maintain capacity to individual meters, that in total, is in excess of the TFE, and at a minimum, sufficient to meet CPA's contractual MDDO/DDQ rights at each point of delivery. These grandfathered MDDO/DDQ rights are not available in new contracts for TCO capacity and any reduction in contracts containing excess grandfathered MDDO/DDQs would result in a proportional reduction in the grandfathered rights. Additionally, this flexibility is critical to the efficient operation of CPA's transportation services, both GDS and CHOICE[SM], and the efficient, least cost management of CPA's capacity portfolio (See Balancing Among Geographic Regions, below).

CPA contracts for storage service from Equitrans under Rate Schedule 115SS, effective April 1, 2020. A portion of the capacity under this contract is used to provide service to GDS customers under CPA's Elective Balancing Service (EBS) with the balance of its use limited to specific geographic areas. The 115SS storage contract has an MDQ of 19,130 Dth, and seasonal storage capacity of 2,000,000 Dth. To deliver this storage service, CPA contracts for 19,130 Dth/day of Equitrans No Notice Firm Transportation Service (NOFTS). In addition, CPA also has an additional 17,000 Dth/day of NOFTS for flowing supply and another 18,870 Dth/day of Firm Transportation Service. Overall, CPA has 55,000 Dth/day of firm capacity with Equitrans.

CPA also contracts for storage service from Eastern Gas Transmission and Storage, Inc. (EGTS) under Rate Schedule GSS and associated FTNN service to provide EBS service. One of these GSS and FTNN contracts is used in concert with the above noted Equitrans capacity to provide EBS. These GSS and FTNN contracts provide a maximum of 4,800 Dth daily and 240,000 Dth of seasonal storage capacity. These contracts were renewed through March 31, 2029. Additionally, CPA contracts for additional storage and related firm transportation service under Rate Schedules GSS, FTNN-GSS and FT with EGTS. CPA has two additional storage capacity contracts under Rate Schedule GSS; one has an MDQ of 9,000 Dth and associated seasonal storage capacity of 941,176 Dth and the second has an MDQ of 15,000 Dth and associated seasonal storage capacity of 930,000 Dth . CPA has two FTNN service contracts for 6,000 Dth per day and 15,000 Dth per day. Additionally, CPA has an FT service for 3,000 Dth per day during the winter which reduces to 2,000 Dth per day in the summer which was renewed through March 31, 2028. CPA also has two FT

contracts, one for 5,000 Dth and one for 255 Dth that expire March 31, 2030. CPA utilizes the first FTNN contract and the FT (winter) contract to match the MDQ of the first storage contract noted above which provide firm storage supplies to CPA's Warrendale market. The first FTNN contract (6,000 Dth per day) has a primary termination date of March 31, 2028. CPA utilizes the second FTNN and FT contracts to serve its State College market. CPA continues to evaluate capacity and supply options in these markets to address the hourly demand requirements on EGTS.

CPA has several forward haul contracts with Texas Eastern Transmission (TETCO) that serve markets in TETCO zones M-2 and M-3 and a seasonal (Dec-Mar) backhaul contract that serves M-3 markets. CPA requires these contracts to serve isolated portions or all of its Uniontown, State College, and York area markets.

CPA solicited bids for replacement capacity for contract 910951 and none were received. As a result, in October 2024, CPA renewed contract 910951 through October 31, 2026, that delivers 14,835 Dth/Day into the TETCO Delmont, Rockwood, and/or Pleasant Gas market.

In April 2023, CPA placed a bid for capacity as part of TETCO's Appalachia to Market III (A2M3) open season. CPA's market in PSP 25 has shown continued growth and additional capacity is needed to meet projected demand growth. The new capacity is projected to be on-line in November of 2027. CPA and TETCO have negotiated a precedent agreement where CPA would have 3,000 Dth/day of new capacity to CPA's York market through October 31, 2028 and 5,000 Dth/day on and after November 1, 2028. The initial term of the transportation contract is 15 years.

CPA has two contracts with Tennessee Gas Pipeline (TGP) that serve portions of its Newcastle and Pittsburgh area markets, one of which is a newer contract with a primary receipt point in the Commonwealth.

CPA obtained under the Right-of-First-Refusal ("ROFR") process a renewal of its Firm Transportation Service (FT-A) contract for 16,000 Dth/day to serve the Newcastle market. This contract has a new expiration date of October 31, 2029.

CPA determined the market served by the Eastern Gas Transmission & Storage (EGTS) Warrendale POD and the Tennessee Gas Pipeline (TGP) Bradford Woods (aka Pitt Terminal) POD needs additional capacity to supply the design day demand. CPA entered into a new contract for 10,500 Dth/day of additional firm capacity to satisfy these needs. This capacity was a winter only contract from November 1, 2025 through March 31, 2026. This capacity may be renewed in the future or additional options may be pursued.

CPA also has contracts with National Fuel Gas Supply Corporation (National). One contract consists of enhanced firm transportation (EFT) of 4,000 Dth per day, of which 1,571 Dth per day with receipt at the Mercer interconnection and delivered to the CPA Findlay Township meter station in Allegheny County, while 2,429 Dth per day will be received from National's storage receipt point and also delivered to the CPA Findlay Township meter station. National also has a firm transportation (FT) contract for 4,245 Dth per day. Additionally, National will provide an enhanced storage service (ESS) with a MSQ of 267,143 Dth, a MDIQ of 1,571 Dth per day, and a MDWIQ of 2,429 Dth per day to be used in combination with the EFT service.

Adding or Replacing Capacity

Before CPA contracts for interstate pipeline capacity, it reviews both open season offerings of new capacity and bulletin board postings of existing capacity. CPA also considers any viable capacity offered by pipelines that currently serve CPA or could do so in the future. Exhibit 2 summarizes proposed capacity services which CPA became aware of, and evaluated in the 12 month period ending January 31, 2025.

CPA may also obtain capacity as follows:

- Natural Gas Suppliers ("NGSs") operating in Pennsylvania, CPA customers and other third parties are given the opportunity to provide capacity comparable to capacity that CPA has under contract and that is approaching expiration.
- If CPA does not have sufficient capacity to meet its Design Day requirements CHOICE[SM] NGSs are given the opportunity to provide FTS capacity for one-year periods.

In more detail, the procedures for obtaining capacity from NGSs are as follows.

Expiration of an Existing Contract and Request for Proposal (RFP) to Natural Gas Suppliers

When the expiration date of an existing capacity contract approaches, CPA gives NGSs licensed to operate in CPA's service territory, CPA customers and other third parties the opportunity to provide comparable capacity. Certain capacities that meet one or more of the following conditions may be excluded:

- operationally necessary to serve CPA's customers,
- required to provide Supplier of Last Resort ("SOLR") services,
- required to provide system balancing.

Considering these conditions, CPA issues RFPs to the NGSs, CPA customers and other third parties offering them the opportunity to provide replacement capacity. The RFP

specifies the delivery points required by CPA to receive gas supplies and outlines the daily delivery volumes for each delivery point. CPA will consider any viable offers it receives. If CPA determines that an offer complies with its RFP and is the best option available, it will enter into an agreement with the offering party. This process of seeking and accepting an offer from an NGS, CPA customer or other third party must be completed in time to allow CPA to terminate the existing capacity that was the subject of the RFP. If acceptable offers are not received, CPA will either extend the existing contract under its own terms and rollover rights or renegotiate the contract. No offers of replacement capacity were received by CPA.

An example of this procedure is CPA's RFP related to its National Fuel capacity. CPA's contract with National Fuel is currently operating on a month-to-month rollover basis and is reviewed annually. In April, 2025, CPA issued an RFP for capacity to replace the National Fuel capacity, effective November 1, 2025. CPA did not receive any responses to its RFP. Therefore, Columbia exercised its annual rollover right and retained the National Fuel capacity under existing contractual provisions, since this capacity is needed to serve the Warren market area.

Additional Capacity Resource Requirement ("ACRR")

Under the CPA CHOICE[SM] Program, NGSs serving CHOICE[SM] customers provide a constant volume of daily supply, equal to the expected annual demand of their customers divided by 365 days.

Effective November 1, 2004, CPA implemented a procedure that gives CHOICE[SM] NGSs the opportunity to provide FTS capacity, for one-year periods beginning each November 1, if CPA does not have sufficient capacity to meet its Design Day Demand. The process works as follows:

- CPA determines the Additional Capacity Resource Requirement ("ACRR"), if any, needed to meet its Design Day Demand.
- CPA notifies NGSs of the ACRR by April 1 of each year.
- The NGSs have the opportunity, until June 1, to offer to provide capacity. The volume of any capacity offered by a CHOICE[SM] NGS may not exceed the daily supply volume of the NGS's aggregation group.
- Should CPA receive offers that in total exceed the ACRR, CPA will accept the offers on a first-come basis until the ACRR is eliminated.

As reflected in Table 4, CPA projects it will have sufficient capacity for the winter of 2026-27 and therefore will not seek additional capacity from NGSs serving CHOICE[SM] customers through the ACRR process for contract year 2026-27. CPA will review its Design

Day supply balance again before the 2027-28 winter season to determine if capacity will be sought through the ACRR process for the 2027-28 contract year.

OPERATION OF TCO STORAGE

Operation Guidelines

As noted on Table 4, approximately 69 percent of CPA's Design Day capacity is provided by storage. In addition, CPA relies upon storage to provide approximately 52 percent of its normal weather, winter season supply to meet the needs of its firm customers and balance system requirements.

CPA follows six guidelines in using its major storage service, TCO FSS:

- to preserve maximum daily storage deliverability on the Design Day and to delay storage ratchets until the design ratchet dates, as presented in Table 5;
- to protect the ability to serve customer requirements during a design cold winter season or month;
- to reserve sufficient TCO storage volumes, at least two percent of contracted seasonal storage quantity, as of April 1 to protect against potential cold temperatures in April;
- to spread TCO FSS storage injections over the months April through October so that no month has a planned injection exceeding 95 percent of the contractual limit for the month;
- to fill TCO storage to 95-99 percent of Seasonal Contract Quantity ("SCQ") on November 1, leaving flexibility to allow for injections on warm days in early November; and
- to use this storage capacity consistent with least cost planning.

CPA's strategy for TCO storage is sufficiently flexible to match customer requirements, under all planning scenarios, while:

- providing the economic benefit from storage utilization, and
- adhering to the operating conditions of TCO storage tariffs.

Using the above storage guidelines, CPA develops a supply plan consisting of seasonal and contract year supply/demand balances. The plan identifies total monthly sources of supply to be used for the colder, normal, and warmer contract year weather scenarios. The

scenario incorporating the colder winter weather constitutes the Design Conditions for which the supply plan is developed.

Tariff Restrictions

Under TCO's tariff, CPA must plan the use of storage such that no more than 65 percent of its TCO FSS seasonal storage quantity remains in inventory after February 1st, and no more than 25 percent after April 1st. In warmer weather winters, this limit may require downward swings in the volume of flowing gas, the gas that CPA has purchased and is transporting to its service territory using its FTS capacity. Downward swings in flowing volumes must be carefully implemented given the potential occurrence of Design Day or extreme cold conditions at any time during the colder winter months. Since CPA requires all flowing supplies to meet firm Design Day Demand, CPA must be able to recall or replace any flowing volumes reduced to comply with storage delivery limits.

If CPA does not reduce its volume in storage to meet the February 1st and April 1st limits, CPA may be subject to pipeline actions ranging from Operational Flow Orders ("OFOs") mandating storage withdrawals, to the potential confiscation by the pipeline of volumes exceeding tariff limits. CPA is also subject to maximum volumes in storage of 60 percent on July 1st and 85 percent on September 1st, requiring close monitoring of summer injection activity.

Storage Ratchets

CPA's primary storage contract, provided by TCO under the Firm Storage Service ("FSS") Rate Schedule, is subject to deliverability reductions, or ratchets, over the course of a winter season as withdrawals reduce storage inventory. CPA manages volumes in storage in the winter to assure that full deliverability is retained late enough into the winter season to cover the Design Date of the Design Day. Furthermore, in Long Range Planning of its capacity portfolio, CPA uses the Monthly Design Days, mentioned earlier in the section titled "Demand," to assure that CPA can serve firm demand on cold days in late winter, after storage withdrawal capacity has ratcheted.

For Operational Planning, which applies to the current winter season, CPA determines ratchet temperature dates based on the capacity currently under contract and 1 in 10 risk criteria. Table 5 summarizes the three pairs of ratchet temperatures and dates for winter 2026-27. The first ratchet, for example, occurs when the inventory falls below 30 percent of the SCQ. It decreases the Maximum Daily Withdrawal Quantity ("MDWQ") to 80 percent of the Maximum Daily Storage Quantity ("MDSQ").

TABLE 5
Design Temperature and Dates of the TCO Storage Ratchets

		Before the Ratchet				**After the Ratchet**
Ratchet		Storage inventory, as a portion of SCQ	Withdrawal capacity MDWQ, as a portion of MDSQ	Temp Deg F.	Last Date before Ratchet: 10 percent risk	Withdrawal capacity MDWQ, as a portion of MDSQ
First		>= 30 percent	100 percent	2	February 14	80 percent
Second		>= 20 percent	80 percent	10	February 23	65 percent
Third		>= 10 percent	65 percent	17	March 8	50 percent

Determination of Design Temperatures and Dates for Storage Ratchets

On the date of the first ratchet, CPA loses daily storage withdrawal capacity equal to 20 percent of its Maximum Daily Storage Quantity ("MDSQ"). After this first ratchet, CPA has enough remaining withdrawal capacity to serve firm demand if daily average temperatures are 3° Fahrenheit or warmer. CPA manages storage activity to delay the first ratchet until days with average daily temperatures of 2° Fahrenheit and colder have less than a 10 percent probability of occurrence. Based on historical temperature data since 1949, the latest occurrence of a 2° Fahrenheit or colder average day temperature, with a 1 in 10 risk of a later occurrence, is February 14th. CPA plans to maintain storage inventory above 30 percent of the Storage Contract Quantity ("SCQ") until February 14th, the design date for the first ratchet. The second and third ratchet dates are developed in a similar manner. Under all weather conditions, CPA will target inventory levels at, or above, levels shown on Table 5 until the ratchet dates shown.

The temperatures and dates associated with storage ratchets may change annually, since:

- the temperature sensitivity coefficients and Design Day Demand are based on CPA's Design Day Forecast, which is updated each year, and
- CPA's supply and capacity contracts may change.

The storage ratchet temperatures and dates are updated prior to the start of the winter heating season.

SUPPLY CONTRACTS AND DAILY BALANCING

Supply Contracts

CPA's supply objective is to secure and deliver competitively priced, reliable gas supplies for its Sales Service Customers. Given current market conditions, CPA contracts for winter season firm supply under contracts for terms from three months to five months. Having a relatively short-term duration portfolio of gas supply contracts enables CPA to adjust its portfolio to changing market conditions, and allows CPA to respond effectively to customer election of alternate suppliers under CPA's Customer CHOICE℠ program.

CPA's purchases of firm gas supplies are primarily made under contracts priced at a published market index price. Spot gas supplies may be purchased at either a published index price or at a negotiated rate.

CPA's supply contracts must meet its reliability criteria. In the months of December through February, CPA assures the reliability of service to its firm customers by contracting for sufficient term supply, along with monthly and daily firm supply purchases, to fill its FTS capacity as required. CPA's strategy in purchasing gas supplies is to remain as flexible as possible consistent with providing reliable service in response to changing market conditions. This strategy holds true in the negotiation of nomination flexibility provisions within those firm supply contracts. Together with storage, CPA's winter purchases are sufficient to meet the human needs requirements of its Sales Service customers.

Daily Balancing

Pipeline tariffs require CPA to balance supply and demand daily at each city gate. CPA's sales and CHOICE℠ customer demand is highly temperature sensitive and varies, or "swings," with changes in temperatures and other factors from day to day. CPA uses TCO's no-notice firm storage service to provide balancing for most of the daily differences between scheduled, flowing supply and demand for all of its customers (Sales, CHOICE℠ and GDS). As previously noted, CPA provides GDS customers daily balancing under EBS. EBS provides a combination of firm and interruptible balancing capabilities that CPA must manage and under which GDS customers or their suppliers must function. While EBS allows GDS customers or their suppliers to deliver more gas than they consume or consume more gas than they deliver on any given day, CPA must manage these deliveries within the confines of its capacity portfolio, the EBS tariff, CHOICE℠ balancing needs and its least cost purchase obligation for its sales customers. When conditions exist that threaten exceeding CPA contractual rights or violation of a pipeline issued operational order, CPA must impose supply restrictions or conditions upon GDS customers and their suppliers to reduce the uncertainty for CPA in regard to GDS customers supply/demand balance and avoid CPA exceeding its contractual rights and/or violating a pipeline issued order and the attendant

higher costs and penalties or from incurring higher costs for its sales and Choice service customers related to such uncertainty.

The TCO storage provides year-round balancing capability. CPA will inject excess gas supply into its storage accounts on days when customer demand is less than the volume of gas supplies scheduled to CPA's city gates. On days when customer demand exceeds the total gas supply volumes scheduled to CPA's city gates, CPA will withdraw gas from its storage accounts. While storage provides the majority of CPA's daily balancing needs, it has daily and monthly limits on both injection and withdrawal. At certain times the daily injection/withdrawal capability of storage is insufficient to meet the potential demand swings of CPA's customers, requiring CPA to increase or decrease its flowing supplies.

CPA's strategy in purchasing gas supplies is to maintain reliable service while remaining as flexible as possible consistent with changing market conditions. This strategy holds true in the negotiation of swing provisions within some firm supply contracts. This provides CPA with required flexibility, consistent with its gas purchase strategy, without incurring additional fixed costs.

Scheduling and Nominations

Along with CPA's purchase and management responsibility comes the requirement to schedule and nominate these supplies on several upstream pipelines with differing nomination requirements and penalty provisions. The operating provisions contained in the pipelines' transportation tariffs require CPA to monitor the flow of gas at its city gate delivery points. Intra-day scheduling changes to nominations can be required to avoid overrun and imbalance charges/penalties contained in the pipelines' tariffs. CPA purchases and nominates all system supply quantities. CPA monitors the supply and demand of its customers and balances any difference. To perform a portion of these responsibilities, CPA utilizes its Supervisory Control and Data Acquisition ("SCADA") system to provide constant monitoring of volumes delivered at its largest city gate delivery points.

Balancing Among Geographic Regions

CPA has a widespread service territory. CPA's service territory currently lies in eight TCO Pipeline Scheduling Points. CPA's service territory includes numerous discrete distribution systems, which are not connected by CPA transmission pipelines. Each distribution system is served by one or more city gate delivery points from interstate pipelines. In total CPA manages approximately 300 such city gate delivery points. CPA is able to aggregate the various supplies and demands at all TCO delivery points for billing and balancing purposes.

Supplies received directly from Equitrans are balanced with CPA's Equitrans storage service. CPA has limited ability to balance supply at Tennessee and TETCO interconnects using Operational Balancing Agreements with the pipelines involved. Similarly, receipts from National Fuel are balanced using a rolling day to day communication and adjustments between the pipeline and CPA.

Identification of Exchanges with Affiliates

The Administrative Law Judge's Recommended Decision in CPA's 2016 1307(f) proceeding, which was adopted by the PaPUC, requires that CPA identify any affiliate exchange, capacity release or off-system sale transactions in its future 1307(f) filings. CPA did not enter into any sales transactions with its affiliates.

SERVICES FOR CHOICE^{SM} CUSTOMERS

CPA's CHOICE^{SM} Service provides customers with the alternative to access gas commodity supplies from NGSs while maintaining the reliability these customers require.

Consistent with the Commission's December 1999 Order on CPA's restructuring, CPA functions as the Supplier of Last Resort ("SOLR") as specified under Section 2207 of the Natural Gas Choice and Competition Act. Included in the SOLR function is service to:

(1) Sales customers that have not chosen an alternative supplier;
(2) customers who have been refused service by natural gas suppliers; and
(3) customers whose CHOICE^{SM} marketers fail to deliver their requirements.

To meet its SOLR obligations, CPA will utilize the capacity assets it has available under contract, including the potential recall of capacity assigned to suppliers under CPA's Customer CHOICE^{SM} Program. That is, if a CHOICE^{SM} marketer assigned capacity exits the Customer CHOICE^{SM} Program or fails to deliver supplies to CPA as provided in its tariff, the capacity will be recalled by CPA, as needed, and utilized to maintain service to the affected customers.

CPA's Customer Assistance Program ("CAP") which previously served its low-income customers through an aggregation program is no longer active per Docket No. M-2023-3039487. These customers are now served under the General Sales Rate.

FEDERAL REGULATORY ACTIVITIES

Columbia takes an active role in Federal Energy Commission (FERC) proceedings that have the potential to impact reliability of natural gas supply to its customers and the cost associated with its delivery, whether these proceedings are pipeline specific or industry wide. Examples include pipeline rate cases, certificate applications, proposed rulemakings and policy statements. Columbia's involvement in these matters includes review, analysis, intervention, comment and collaboration. In compliance with Section 53.64 (C)(4) of the Commission's regulations.

Columbia intervenes in all FERC dockets when certificate and rate filings have the potential to impact reliability and/or cost to its customers. Please see Exhibit No. 3 for details of activities undertaken by Columbia at the FERC during 2025.

OFF-SYSTEM SALES AND CAPACITY RELEASE INCENTIVE PROGRAM

A market exists for NGDCs, such as CPA, to market unbundled and rebundled gas and capacity products to non-traditional customers. CPA's off-system sales and capacity release program provides CPA and its customers an opportunity to benefit from the unbundling of interstate pipeline services implemented by FERC Order 636.

CPA's off system sales incentives began in January 1995 and capacity release incentives began in February 1996. The results of these incentive mechanisms have been positive for both customers and CPA as interested parties and the Commission have recognized the importance of a balanced incentive in these programs. CPA continues to seek opportunities to create value for its customers under these incentive mechanisms within its least cost procurement plan.

COLUMBIA STATEMENT NO. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2026-3060762
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF

MATTHEW VORNDRAN

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2026

Q. Please state your name and business address.

A. My name is Matthew Vorndran and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am employed by NiSource Corporate Services Company ("NCSC"), which is a service company for NiSource Inc. that serves Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company"), as a Senior Regulatory Analyst in the Rates and Regulatory Department.

Q. What are your responsibilities as Senior Regulatory Analyst?

A. I am responsible for the preparation and support of Pennsylvania Public Utility Commission ("Commission") regulatory filings for Columbia, with duties including purchased gas cost filings and other recovery mechanisms. I am also responsible for the implementation of Columbia's rates into the Company's billing system.

Q. What is your educational and professional background?

A. I graduated from the University of Cincinnati with a Bachelor of Arts in Economics. In 2018, I was hired by Columbia Gas of Ohio, Inc. ("COH") as a third-party contractor to perform an analysis on COH's Energy Efficiency programs. In 2021, I joined COH as the Financial and Analytics Lead, performing further data analysis related to the financial performance and effectiveness of the COH Energy Efficiency programs. In 2023, I transitioned into the Rates and Regulatory Department as a Senior Regulatory Analyst, supporting Columbia Gas of Maryland, Inc. and then moved to my current role supporting the Company in 2025.

Q. Have you previously testified in proceedings before this or any other Commission?

A. No, I have not.

Q. Please describe the scope of your testimony in this proceeding.

A. I am responsible for the overall presentation of Exhibit Nos. 1-A through 1-F, which were submitted in response to the Commission's requirements in 52 Pa. Code § 53.64, *et seq*. I am also sponsoring Columbia Exhibit MV-1, which computes Columbia's retainage rate for transportation customers.

Q. Were the exhibits that you are sponsoring prepared by you or by persons working under your direction?

A. Yes, they were.

Q. Are there any updates to the exhibits you are sponsoring?

A. Yes. Revised Exhibit 1-A and Revised Exhibit 1-B are submitted with this testimony to replace Exhibit 1-A and Exhibit 1-B submitted in the 1307(f) pre-filing on February 27, 2026.

Q Why are revised exhibits being submitted?

A. Following the preparation of the pre-filing, it was determined that the Off System Sales and Capacity Release Credit rate reflecting a two-year average of the customer's portion of United Sharing Mechanisms ("USM") credits had not been updated to reflect a two-year average for 12-month periods ending September 2025 and September 2026 and had instead reflected a two-year average for 12-month periods ending September 2024 and September 2025. Footnotes 3 and 4 on Revised Exhibit 1-A, Schedule 3, Sheet 2 were also updated to match the billing

determinants on line 4a and the capacity allocations on line 7. Additionally, the contract relating to the Columbia Gas Transmission, LLC ("TCO") Capacity Release on Revised Exhibit 1-B, Schedule 2, Sheet 1, line 2 was updated with new quantities for the period November 2026 through September 2027.

Q. Please explain the changes to Revised Exhibit 1-A.

A. Revised Exhibit 1-A has been updated to reflect an updated Off System Sales and Capacity Release Credit rate on Schedule 1, Sheet 1, Line 22 and Schedule 3, Sheet 1, Line 9, reflecting an updated two-year average of USM credits. In Schedule 1, Sheet 1 of 2, the updated exhibit includes the Purchased Gas Demand Cost ("PGDC") rate of $0.23996 per therm and the Purchased Gas Cost ("PGC") rate of $0.60141 per therm. Both the PGDC and PGC rates have increased by $0.00038 per therm from the corresponding rates submitted in the pre-filing. This is not a material change to the exhibit or pre-filing materials. The entire Revised Exhibit 1-A is attached hereto for ease of reference.

Q. Please explain the changes to Revised Exhibit 1-B.

A. Revised Exhibit 1-B has been updated to reflect updated Capacity Release quantities on Schedule 2, Sheet 1, Line 2 for the period November 2026 through September 2027. Beginning November 2026, the 4,000 dth release of capacity is reduced to 2,700 dth to match projected revisions with the contract with a large industrial customer. In Schedule 1, Sheet 1 of 4, the updated exhibit includes the Total Demand Cost of $115,897,222 and the Total Estimated Gas Costs of $255,017,164. Both the Total Demand Cost and Total Estimated Gas Costs have increased by $190,443 from the corresponding totals submitted in the pre-filing.

Please note that the only changes in Revised Exhibit 1-B are in Schedule 1, Sheets 1 and 2 and Schedule 2. However, the entire Revised Exhibit 1-B is attached hereto for ease of reference.

Q. Is the information contained within the exhibits and revised exhibits that you are sponsoring true and correct to the best of your knowledge and belief?

A. Yes, it is.

Q. What are the total projected changes in sales service rates to become effective October 1, 2026, for recovery of purchased gas costs?

A. Referring to Revised Exhibit No. 1–A, Schedule 1, Sheet 1 of 2, Columbia has projected an overall increase of $0.04700 per therm to its PGC rate including E-Factor for customers served under Rate RSS – Residential Sales Service, Rate SGSS – Small General Sales Service, and Rate LGSS – Large General Sales Service, as compared to rates then currently in effect as of February 27, 2026. I note that this rate will likely be revised in the future, based upon updates to the filing.

Q. What are the principal reasons for this projected change in the overall PGC rate?

A. The change is driven primarily by the change in the E-factor to recover prior period under/over collections resulting in an increase of $0.03259 per therm. During the current 1307(f) reconciliation period, customers are being credited $0.00923 per therm through the E-factor. The projections for the application period show that the Company will be in an under collected position and, therefore, the E-factor rate is projected to be $0.02336 per therm, for an overall increase of $0.03259 per

therm. The secondary driver is the increase in the projected gas costs for the application period. The increase in the projected gas costs and E-factor result in an overall increase of $0.04700 per therm. These changes are detailed on Revised Exhibit 1-A, Schedule 1, Sheet 1 of 2.

Q. Please describe the Company's calculation of retainage.

A. In accordance with the Commission's orders in prior PGC proceedings (Docket Nos. R-2009-2093219 and R-2010-2161920), Columbia has calculated retainage based on a three-year rolling average, with an August 31st ending date for each year, which excludes Mainline Class I customer quantities and includes Company Use in the calculation. Exhibit MV-1, attached to my Direct Testimony, provides the calculation of the retainage rate to be effective January 1, 2027, resulting from the three-year average ending August 31, 2025. The retainage rate will be 1.3%.

Q. Please describe Revised Exhibit 1-A, Schedule 1, Sheet 2.

A. This sheet demonstrates the calculation of the Daily Purchased Gas Demand Rate under Rate SS. This calculation is based on the total estimated demand charges for the projected period October 2026 through September 2027, divided by Columbia's total demand billing determinants for the same period.

Q. Please describe Revised Exhibit 1-A, Schedule 2.

A. Revised Exhibit 1-A, Schedule 2, Sheets 1 through 4 detail the calculation of the over/under-collection for the period of October 2026 through September 2027. This schedule shows that the rates contained in Revised Exhibit 1-A would recover the projected gas costs included in Columbia's filing based upon projected quantities. Any balance at the end of the period is due to rounding.

Q. Please describe Revised Exhibit 1-A, Schedule 3.

A. Revised Exhibit 1-A, Schedule 3 details the calculation of the purchased gas demand charge that is paid by customers selecting Columbia's CHOICE[SM] service. Columbia's CHOICE[SM] service offers residential customers and commercial customers an opportunity to purchase their natural gas supply service from a licensed Natural Gas Supplier ("NGS") under rates Residential Distribution Service ("RDS") and Small Commercial Distribution ("SCD"). Under CHOICE[SM] service, NGSs are assigned, and pay for, a portion of Columbia's pipeline capacity. The NGS must deliver an amount of gas every day of the year that is equal to 1/365th of the NGS customer group's annual normalized consumption. Under the CHOICE[SM] program, Columbia manages daily imbalances with retained capacity and storage. Those customers who select an NGS are subject to the purchased gas demand component of Columbia's purchased gas cost rate, net of a credit to reflect the cost of TCO and Eastern Gas Transmission and Storage, Inc. ("EGTS") pipeline capacity assignable to their NGS. The credit for the upcoming PGC period is $0.03763 per therm.

Q. Please describe Revised Exhibit 1-B.

A. Revised Exhibit 1-B is submitted in response to the Commission's filing requirement at 52 Pa. Code § 53.64(c)(1) and details the monthly projected purchases from the Company's various gas suppliers for the period October 2026 through September 2027. Revised Exhibit 1-B consists of ten schedules that detail and summarize the estimated purchased gas demand costs from TCO, Texas Eastern Transmission Corp ("TETCO"), EGTS, Tennessee Gas Pipeline Co.

("Tennessee"), National Fuel Gas ("National Fuel"), and Equitrans, and projected commodity purchases from various interstate suppliers, storage, and Pennsylvania local producers.

The monthly projected purchases included in Revised Exhibit 1-B, Schedule 1, Sheet 1 of 4, are the twelve-month summary of the estimated demand and commodity costs of gas. As indicated on line 5 of Schedule 1, Sheet 1, the total projected cost of gas for the twelve-month period is $255,017,164.

Revised Exhibit 1-B, Schedule 1, Sheet 2 of 4 summarizes the projected demand cost from Revised Exhibit 1-B, Schedules 2 through 7 for the October 2026 through September 2027 period, by month and by pipeline. Schedule 1, Sheet 2 includes a fixed annual credit of $300,000 related to the provision of Elective Balancing Service ("EBS") approved by the Commission in the settlement at Docket No. R-00016668. Schedule 1, Sheet 3 summarizes the projected commodity costs from Schedules 8 through 10 by month and by source. Schedule 1, Sheet 4 is a summary of the projected commodity quantities, in Dth, by month and by source. The demand and commodity costs have been brought forward to Revised Exhibit 1-A to be used in the computation of rates.

Q. Please continue with your explanation of the other schedules contained in Revised Exhibit 1-B.

A. Revised Exhibit 1-B, Schedules 2 through 7 detail the projected demand cost reflected on Schedule 1, Sheet 2. The projection of the demand costs for each pipeline is based on the projected monthly capacity and the projected demand rates.

Table 1 below summarizes the pipelines and the projected demand cost related to each:

Table 1 Projected Pipeline Demand Costs from Revised Exhibit 1-B		
Columbia Gas Transmission, LLC	Schedule 2	$ 103,400,151
Texas Eastern Transmission Corporation	Schedule 3	$ 4,372,788
Eastern Gas Transmission and Storage	Schedule 4	$ 3,261,801
Tennessee Gas Pipeline	Schedule 5	$ 1,471,948
National Fuel Gas Supply Corporation	Schedule 6	$ 935,076
Equitrans	Schedule 7	$ 2,755,458

Company Witness Tina Monnig will provide additional details regarding capacity contract changes.

Q. Please explain the development of the projected commodity cost reflected in Revised Exhibit 1-B.

A. The projected commodity cost shown on Revised Exhibit 1-B, Schedule 1, Sheet 3 is detailed in Schedules 8 through 10 of Revised Exhibit 1-B. The detail of the projected commodity cost is by month and by source.

Schedule 8 details the projected purchases of gas under term contracts. Columbia will be utilizing transportation capacity on several pipelines and in different combinations for its term contracts. The purchase price for this gas reflects the commodity cost of the gas delivered to all the city gates. The product of the projected purchases times the projected city gate purchase rates amounts to

$23,199,825. Under Columbia's Universal Service and Conservation plan order at Docket No. M-2023-3039487, as of April 4, 2024, Columbia discontinued the process of aggregate shopping for natural gas supplied to Columbia's Customer Assistance Program ("CAP") customers due to lack of interest by natural gas suppliers. Therefore, CAP customers are served by Columbia sales service and CAP purchases or CAP billings were removed from Schedule 8.

Schedule 9 details the projected purchases of spot gas (line 9 - $114,650,993) and local gas (line 15 - $820,010). The total projected cost of these purchases is $115,471,003.

Schedule 10 is a listing of the projected monthly gas commodity storage costs. Columbia will use storage from EGTS, Equitrans, TCO, and National Fuel. The total net cost of gas from storage is projected to be ($3,341,168). This amount includes the injection/withdrawal charges and the transportation commodity costs. Monthly injections are priced at the average commodity cost of gas purchased for the month. Monthly withdrawals of gas from storage are based on the average cost of gas in storage for the month.

Q. Please describe Exhibit 1-C.

A. Exhibit 1-C is submitted in accordance with § 53.64(c)(1) of the Commission's regulations and sets forth the total estimated purchased gas costs from all gas supply sources for the period February 2026 through September 2026. Exhibit 1-C consists of ten schedules detailing the projected transportation and storage capacity cost of purchases from TCO, TETCO, EGTS, Tennessee, National Fuel,

and Equitrans, and projected commodity purchases from interstate suppliers, storage, and Pennsylvania local producers.

Q. Please describe the schedules included in Exhibit 1-C.

A. Exhibit 1-C, Schedule 1, Sheet 1 sets forth the summary of the total estimated purchased gas costs, by month, for the period February 2026 through September 2026. Schedule 1, Sheet 2 summarizes the total estimated purchased gas demand costs by month and pipeline for the period February 2026 through September 2026.

Exhibit 1-C, Schedule 1, Sheet 3 summarizes the total estimated purchased gas commodity costs, by month and by source, which are further detailed on Schedules 8 through 10.

Exhibit 1-C, Schedule 1, Sheet 4 is a summary of the total estimated purchased gas commodity quantities, in Dth, by month and by source.

Q. Please explain the projected demand cost development.

A. Exhibit 1-C, Schedules 2 through 7 detail the projected demand costs reflected on Schedule 1, Sheet 2, by pipeline company. The projection of the demand costs for each pipeline company is based on the projected monthly capacity and the projected demand rates. Table 2 below summarizes the pipelines and the projected demand cost related to each:

Table 2 Projected Pipeline Demand Costs from Exhibit 1-C		
Columbia Gas Transmission, LLC	Schedule 2	$63,615,496
Texas Eastern Transmission Corporation	Schedule 3	$2,846,992
Eastern Gas Transmission and Storage	Schedule 4	$2,119,034
Tennessee Gas Pipeline	Schedule 5	$954,776
National Fuel Gas Supply Corporation	Schedule 6	$623,384
Equitrans	Schedule 7	$1,505,460

Q. Please explain the projected commodity cost development.

A. The projected commodity cost shown on Exhibit 1-C, Schedule 1, Sheet 3, is detailed in Schedules 8 through 10. The detail of the projected commodity cost is by month and by source.

Schedule 8 details the total estimated purchased gas commodity costs under term contracts. Columbia will be using transportation capacity on several pipelines and in different combinations. The purchase price for this gas reflects the commodity cost of the gas delivered to the city gate. The product of the projected purchases times the projected city gate purchase rates equals $7,176,049 of projected purchased gas commodity cost. As explained previously, CAP purchases or CAP billings were removed from this schedule.

Schedule 9 provides details, for each month in the February 2026 to September 2026 period, of the total estimated purchased gas commodity costs associated with spot and local gas purchases. The projected cost of these purchases is $74,443,084 (line 9 – $73,959,658 + line 15 – $483,426).

Schedule 10 shows the total estimated purchased gas commodity costs associated with storage. Columbia will use storage from EGTS, Equitrans, TCO, and National Fuel to provide service to customers. The total cost of gas from storage for the eight-month period February 2026 through September 2026 is projected to be ($33,871,447), which includes the injection/withdrawal charges and the transportation commodity cost. The monthly injection and withdrawal rates were developed utilizing the methodology discussed in relation to Revised Exhibit 1-B, Schedule 10.

Q. Please describe the calculations contained in Exhibit 1-D.

A. Exhibit 1-D is provided in compliance with § 53.64(c)(1) of the Commission's regulations. Exhibit 1-D, Schedule 1 sets forth the historic cost of gas by type and month for the February 2025 through January 2026 period. Section 53.64(c)(1) requires Columbia to file a complete listing of the sources of gas supply used in the prior twelve months that ends two months prior to the date of the Company's tariff filing. Exhibit 1-D consists of six schedules detailing the historic cost of gas purchased from interstate sources through transportation arrangements with interstate pipelines, Pennsylvania local producers, and underground storage. Exhibit 1-D, Schedule 1, Sheet 1 summarizes the total costs associated with the purchases. Exhibit 1-D, Schedule 1, Sheet 2 itemizes the demand and commodity costs shown on Exhibit 1-D, Schedule 1. Exhibit 1-D, Schedule 1, Sheet 3 details the volumes associated with the purchases. Exhibit 1-D, Schedules 2 through 6 provide

additional detail on the purchases by type and month. Columbia Witness Patrick Pluard is supporting Exhibits 1-D-1 through 1-D-3.

Q. Please describe Exhibit 1-E.

A. Exhibit 1-E, which consists of four schedules, sets forth the calculations supporting the experienced net over/under-collection level used in the rate recovery calculation.

Q. Please describe Exhibit 1-E, Schedule 1.

A. Exhibit 1-E, Schedule 1 shows a summary of all components used in the calculation of the over/under-collection portion of the PGC rate scheduled to become effective October 1, 2026. Schedule 1, Line 9 reflects a projected total experienced net under-collection of $6,614,336. This under-collection amount includes: 1) anticipated over/under-collection during the 2025 § 1307(f) Application Period (October 2025 through September 2026); 2) reconciliation of prior period proceeds received for off-system sales and capacity releases; and 3) reconciliation of prior period over/under-collections.

Q. Please explain the calculations on Exhibit 1-E, Schedules 2a and 2b.

A. Schedules 2a and 2b set forth the reconciliation of prior period commodity and demand costs from the 2025 PGC period of ($9,751,156) to be collected and $15,990,256 to be passed back.

Line 19 of Schedule 2a reflects the estimated prior period commodity under-collection of $6,493,394 that Columbia anticipates it will experience for the twelve months ending September 2026. This estimated prior period commodity under-collection is calculated by adding: 1) the under-collected commodity balance as of

September 2025 (line 1); 2) a beginning balance adjustment (line 2) of ($76,306); and 3) the sum of the actual and projected refunds and recoveries for the period October 2025 through September 2026 (line 18).

Line 19 of Schedule 2b reflects the estimated prior period demand over-collection of $8,722,936 that Columbia anticipates it will experience for the twelve months ending September 2026. This estimated prior period demand over-collection is calculated by adding: 1) the over-collected demand balance as of September 30, 2025 (Line 1); 2) a beginning balance adjustment of ($120,395); and 3) the sum of the actual and projected refunds and recoveries for the period October 2025 through September 2026 (line 18).

Q. Please explain the beginning balance adjustments on Schedules 2a and 2b.

A. The beginning balance adjustment on Schedule 2a of ($76,306) represents a commodity interest adjustment for the months of February 2025 through September 2026, decreasing the interest rate from 7.50% to 6.75% to reflect the prime interest rate as of January 31, 2026. The beginning balance adjustment of ($120,395) on Schedule 2b represents a demand interest adjustment for the months February 2025 through September 2025, decreasing the interest rate from 7.50% to 6.75% to reflect the prime interest rate as of January 31, 2026.

Q. Please explain the calculations on Schedule 3.

A. Schedule 3 reflects the calculation of the estimated net - over-refunded USM proceeds of $571,829, as shown on Exhibit 1-E, Schedule 1, line 4. The purpose of

this calculation is to estimate the portion of the USM proceeds that will be collected during the current PGC period.

Q. How was the estimated net over-refunded amount of $571,829 for USM proceeds determined?

A. As indicated on Exhibit 1-E, Schedule 3, Columbia included in the E-factor a projected total credit of $2,465,607 for the USM. This is the current estimate of the customers' share of off-system sales and capacity release net proceeds for the twelve months ended September 30, 2026. This amount is allocated 100% to the PGDC (Schedule 3, line 16). Currently, Columbia projects to pass back $3,037,436 in USM credits, based upon actual and projected volumes subject to the credit. The result is an over-refund of $571,829.

Q. Please continue with your explanation of Exhibit 1-E, Schedule 4.

A. Schedule 4 reflects the statement of over/under-collections expected from the application of Columbia's PGC rates for the period October 2025 through September 2026. The monthly over/under-collection amounts for the period October 2025 through January 2026 are based on actual data. The monthly over/under-collection amounts for the period February 2026 through September 2026 are based on projected data. I note that, under the Commission's PGC regulations, the projected amounts will be replaced with actual costs and recoveries through August 2026 as part of Columbia's compliance filing. Exhibit 1-E, Schedule 4, Sheet 1a depicts the calculation of the commodity over/(under) collection, while Exhibit 1-E, Schedule 4, Sheet 1b depicts the calculation of the demand over/(under) collection. The estimated total under-collection of

$7,837,545, derived by combining both sheets, is carried forward to Exhibit 1-E, Schedule 1, line 6. Likewise, interest associated with the commodity and demand under collections totaling $434,505 is also calculated on Exhibit 1-E, Schedule 4, Sheets 1a and 1b respectively, and is carried to Exhibit 1-E, Schedule 1, line 8, so that it is included in the E-factor.

Q. How was interest calculated?

A. Interest was calculated at the rate of 6.75% for the months of October 2025 through September 2026 for over/under collections from gas costs. This is the prime rate for commercial borrowing in effect as of January 31, 2026, as reported in The Wall Street Journal, Market Data section under Prime Rate. Columbia applies the prime interest rate for commercial borrowing effective January 31 at the end of the historic reconciliation period, which counsel has advised me is consistent with Act 47's requirement that utilities use the prime rate for commercial borrowing in effect 60 days prior to their annual 1307(f) tariff filing. Columbia will update the interest rate, if necessary, for the February 2026 through September 2026 period in next year's 1307(f) filing and calculate interest for the months of October 2026 through January 2027 based on the prime interest rate for commercial borrowing for the twelve months ending January 31, 2027.

Q. How is the cost of fuel recovery calculated?

A. The cost of fuel recovery is shown on Exhibit 1-E, Schedule 4, Sheet 1a, Column 3 and Sheet 1b, Column 5. Columbia's PGC recovery rates applicable to customers receiving service under Rate RSS, Rate SGSS, and Rate LGSS consist of both PGCC and PGDC components. Rate NSS – Negotiated Sales Service customers pay a cost

of gas based on the cost of spot purchases scheduled to flow on the first day of the month. Customers receiving service under Rate SGDS Priority One, Rate SCD and Rate RDS pay only the PGDC rate for volumes transported. Exhibit 1-E, Schedule 4, Sheet 2a, Column 2 shows the PGCC rate that is applied to all sales under Rate RSS, Rate SGSS and Rate LGSS. Exhibit 1-E, Schedule 4, Sheet 3, column 3 shows the recovery of gas costs from Rate NSS customers.

Q. Please explain the calculation of the total demand revenue included in Exhibit 1-E, Schedule 4, Sheet 1b, column 5 that was used to calculate the over/under-collection included in the pre-filing information.

A. Exhibit 1-E, Schedule 4, Sheet 1b, Column 5 summarizes the total purchased gas demand revenue collected from customers. The details of the purchased gas demand revenue are shown on Sheets 4a through 6. Estimated total purchased gas demand revenue recovery is $119,154,336.

Q. Please explain the calculation of the EBS Option 2 revenue in Exhibit 1-E, Schedule 4, Sheet 1b, Column 2 that was used to calculate the over/under-collection.

A. Exhibit 1-E, Schedule 4, Sheet 1b, Column 2 provides a summary of Rider EBS Option 2 revenues collected from one Rate NSS customer. Currently, no General Distribution Service customers have elected Option 2. The detailed calculation of the revenue is shown on Exhibit 1-E, Schedule 4, Sheet 6. Estimated total balancing revenue for the period October 2025 through September 2026 is $597.

Q. Please explain the calculation of Capacity Release revenue under Rate NSS as contained on Schedule 4, Sheet 1b, Column 4.

A. The calculation of the Capacity Release revenues from Rate Schedule NSS is detailed on Exhibit No. 1-E, Schedule 4, Sheet 6. Estimated total revenue from Rate NSS Capacity Release for the period October 2025 through September 2026 is $5,458.

Q. Columbia's tariff contains several special provisions for Rate NSS. One provision is that any customer served under Rate NSS with an annual throughput requirement below 64,400 therms be reported through the 1307(f) process. Does Columbia have any such customers?

A. No. The one Rate NSS customer identified two responses prior has an annual throughput that is greater than 64,400 therms.

Q. Please describe Exhibit 1-F, Schedule 1.

A. Schedule 1 of Exhibit 1-F constitutes Columbia's statement of over/under-collections during the twelve months ended January 31, 2026. This schedule, which is submitted in compliance with § 53.64(i)(1)(i)-(iv) of the Commission's regulations, reflects an under-collection of $8,894,625 as detailed on Schedule 1, Sheet 1. Exhibit 1-F, Schedule 1, Sheets 1a and 1b, respectively, depict the calculations for the commodity over/under collection, the demand over/under collection, the commodity over/under collection with an itemization for Rate NSS, and the demand over/under collection with an itemization for Rates SS and NSS. Exhibit 1-F, Schedule 1, Sheet 2a, reconciles the differences between the Company's total purchased gas costs, as reflected on Exhibit 1-D and the Company's financial statements, with the cost of fuel shown for PGC purposes, which appears on Exhibit 1-F, Schedule 1, Sheet 1. Exhibit 1-F, Schedule 1, Sheet

2b reconciles the gas commodity purchases reflected in Exhibit 1-D and the commodity cost of fuel for PGC purposes shown on Exhibit 1-F, Schedule 1, Sheet 1a, as agreed to in the Settlement of the 1307(f) proceeding at Docket No. R-2012-2293303.

Q. Did natural gas costs exceed revenues collected by more than 10% in the previous 12-month period due to customers switching from sales service to transportation service as described in Act 47?

A. No. Exhibit 1-F, Schedule 1, Sheet 1 shows the Company in an under-collected position for the historical 12-month period ending January 2026, of 3.53%.

Q. Please explain Exhibit 1-F, Schedule 2.

A. Exhibit 1-F, Schedule 2, attached to my Direct Testimony, is provided in compliance with § 53.64(i)(1)(iv) and (v) of the Commission's regulations. This schedule details the difference between actual costs for the period February 2025 through January 2026, and projected costs included in the gas cost recovery components established in the 2024 1307(f) proceeding for the period February 2025 through September 2025, and in the 2025 1307(f) proceeding for the period October 2025 through January 2026.

Q. Please provide the basis for how the customers' portion of USM revenues are projected.

A. Per the 2019 1307(f) Settlement approved by the Commission at Docket No. R-2019-3008255, the USM projection of the customers' share of revenue is calculated using a two-year PGC period average, with one year being the most recently completed PGC period available at the time the PGC pre-filing is

submitted and the second year being the projected customer share of USM net margin for the current PGC filing year at the time the pre-filing is submitted.

Q. Please provide the calculation utilized to develop the USM rate in the pre-filing that utilizes the two-year average described above.

A. Please see the calculation below. This rate is shown on Revised Exhibit 1-A, Schedule 1, line 22.

2026 1307(f) Application Filing
PGC Period October 1, 2026 - September 30, 2027

PGC Period		USM- Customer Portion	
Oct 24-Sept 25 PGC Period (Actual)	$	(3,723,721)	
Oct 25-Sept 26 PGC Period (Estimate)	$	(2,465,607)	
2 Year Average	$	(3,094,664)	
Projected Demand Sales October 1, 2026 - September 30, 2027		465,805,757	Therms
Off Systems Sales and Capacity Release Credit	$	(0.00664)	per Therm

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

§ 53.64(i)(1)(iv)(v)

(i) Utilities shall comply with the following:

(1) Thirty days prior to the filing of a tariff reflecting increases or decreases in purchased gas expenses, gas utilities under 66 Pa.C.S. § 1307(f) recovering expenses under that section shall file a statement for the 12-month period ending 2 months prior to the filing date under 66 Pa.C.S. § 1307(f) as published in accordance with subsection (b) which shall specify:

(iv) Evidence explaining how actual costs incurred differ from the costs allowed under subparagraph (ii).

(v) How these costs are consistent with a least cost fuel procurement policy, as required by 66 Pa.C.S. § 1318 (relating to determination of just and reasonable natural gas rates).

Response:

Exhibit No. 1-F, Schedule 1 of Columbia's 2026 1307(f) filed February 27, 2026, constitutes the Company's Statement of Over/Under Collections From Gas Cost Rate, as required by Section 53.64(i)(1) for the twelve-month period ended January 31, 2026. Exhibit No. 1-F, Schedule 1, Sheet 1 indicates that Columbia was under-collected by $8,894,625 at January 31, 2026, resulting from gas costs of $251,841,224 and gas cost recoveries of $242,946,599.

A company’s experienced over-collections or under-collections are caused by variances that occur between projected and actual gas costs, and between projected and actual gas cost recoveries.

The projection of gas cost recoveries follows the 1307(f) cycle through a period of under-collections during months of high usage, followed by a period of over-collections occurring during months of low usage. In its PGC filing effective January 1, 2025, Columbia projected gas costs for February 2025 through September 2025 of $140,341,188. Gas cost recoveries were projected at $138,163,728 for this same period. Accordingly, these months were projected to produce a net under-collection of $2,177,461 (Exhibit 1-A, Schedule 2, Sheet 4).

Actual gas costs for the months of February 2025 through September 2025 (2026 1307(f) Exhibit 1-F, Schedule 1, Sheet 1) totaled $119,270,172, a $21,071,016 decrease from the projections included in the January 1, 2025 PGC filing. As Columbia progressed through the 2024 1307(f) period and incrementally adjusted its recovery rates in subsequent filings, recoveries for the same period were recorded at $134,222,783, representing a decrease in gas cost recoveries of $3,940,945 from the January 1, 2025 PGC filing projections. In total Columbia experienced a net over-collection for the months of February 2025 through September 2025, which ended the 2024 1307(f) cycle, in the amount of $14,952,611.

As Columbia's computation of historic reconciliation period over/under collections overlaps two separate 1307(f) periods, the remaining months of October 2025 through January 2026 will now be discussed.

In the October 1, 2025 PGC filing (Exhibit 1-A, Schedule 2, Sheet 4), Columbia projected gas costs for the months of October 2025 through January 2026 to total $109,815,548 with gas cost recoveries for the same period projected at $100,157,553, for an expected under-collection of $9,657,995. Columbia's actual gas costs for the months of October 2025 through January 2026 (2026 1307(f) Exhibit 1-F, Schedule 1) were $132,571,052, which is an increase from October's gas cost projections of $22,755,504. As Columbia progressed through the 2025 1307(f) period and incrementally adjusted its recovery rates in subsequent filings, recoveries for the months of October 2025 through January 2026, were recorded at $108,723,815 (2026 1307(f) Exhibit 1-F, Schedule 1). This is an increase of $8,566,262 when compared with the October 1, 2025 PGC gas cost recovery projections. Overall, the net variance between actual gas costs and gas cost recoveries for the months of October 2025 through January 2026 resulted in a net under-collection of $23,847,236.

Together the net over-collection from the 2024 1307(f) months of February 2025 through September 2025 of $14,952,611 and the net under-collection of $23,847,236 for the 2025 1307(f) months of October 2025 through January 2026 results in a total net under-collection of $8,894,625 for the twelve-month period ending January 31, 2026. The net under-collections consist of a commodity under-collection of $22,935,939 and a demand over-collection of $14,041,314.

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Columbia Gas of Pennsylvania, Inc.

Exhibit MV-1

	Year End Aug-31	2023	2024	2025	3-Year Averages 2023 - 2025	
		Dth	Dth	Dth	Dth	
	Supply					
1	Raw Supply Numbers	78,067,318	74,753,173	80,274,705	77,698,399	
2	Supply Adjustment	704	-698	-446	-147	
3	Cumulative Adj. Supply - Including Supply Adjustments	78,068,022	74,752,475	80,274,259	77,698,252	
4						
5	ML1 Volumes	2,816,378	2,976,033	2,922,122	2,904,844	
6	Cumulative Adj. Supply Including Supply Adj. Less ML1	75,251,644	71,776,442	77,352,137	74,793,408	
7	Excess Pressure Volumes	24,520,795	24,227,441	23,517,657	24,088,631	
8	Cumulative Adj. Supply Including Supply Adj. Less Excess Pressure and ML1	50,730,849	47,549,001	53,834,480	50,704,777	
	Consumption					
9	Residential	31,250,450	29,052,614	32,542,743	30,948,602	
10	Commercial	22,671,129	21,582,024	23,488,190	22,580,448	
11	Industrial	22,937,550	22,850,927	22,796,155	22,861,544	
12	Other	2,439	3,221	3,501	3,054	
13	Electric Gen.	404,820	387,926	388,964	393,903	
14	Company Use	133,876	133,564	59,223	108,888	
15	Subtotal Consumption	77,400,264	74,010,276	79,278,776	76,896,439	
16	ML1 Volumes	2,816,378	2,976,033	2,922,122	2,904,844	
17	Excess Pressure	24,278,015	23,987,565	23,284,809	23,850,130	
18	Total Consumption - Includes Company Use but not ML1 (18 = 15 - 16)	74,583,886	71,034,243	76,356,654	73,991,594	
19	Total Consumption-Includes Company Use Less ML1 and Excess Pressure (19 = 18 -17)	50,305,871	47,046,678	53,071,845	50,141,465	
	Retainage					
19	Retainage-Includes Company Use Less ML1	801,634	875,763	1,054,706	910,701	
20	Rate (20 = 19 / 6)	1.1%	1.2%	1.4%	1.1%	
21	Retainage - Includes Company Use but not ML1 nor Excess Pressure	558,854	635,887	821,858	672,200	
22	Rate (22 = 21 / 8)	1.1%	1.3%	1.5%	1.3%	(1)

(1) Rate to be in effect as of January 1, 2027.

COLUMBIA GAS OF PENNSYLVANIA, INC.
COMPUTATION OF CHANGE IN RATE PURSUANT TO SECTION 1307(f)
APPLICATION PERIOD: OCTOBER, 2026 THROUGH SEPTEMBER, 2027

Line No.	Description		Amount (1)	
1	Purchased Gas Commodity Cost		$	
2	Commodity Cost of Gas (Exhibit 1-B, Schedule 1)		139,119,942	
3	Projected tariff sales for the twelve billing periods of			
4	October, 2026 through September, 2027		384,465,070	Therms
5	PGCC (Line 2/Line 4)		0.36185	
6	Commodity (Over)/Under Collection			
7	Commodity E-Factor			
8	(Exhibit No. 1-E)		20,165,464	
9	Projected sales for the twelve billing periods of			
10	October, 2026 through September, 2027		384,465,070	Therms
11	Commodity E-Factor (Line 8/ Line 10)		0.05245	
12	Purchased Gas Demand Cost			
13	Demand cost of gas (Exhibit 1-B, Schedule 1)		115,897,222	
14	Less: Purchased Gas Demand recovered under Rate SS			
15	(Exhibit 1-A, Schedule 2, Sheet 2)		1,027,401	
16	Less: Purchased Gas Demand Cost allocated to Rates LTS, STS,			
17	SGS-TS and MLS (Exh 1-A, Sch 2, Page 3)		0	
18	Subtotal (Line 13 - Line 15 - Line 17)		114,869,821	
19	Projected sales for the twelve billing periods of			
20	October, 2026 through September, 2027	1_/	465,805,757	Therms
21	PGDC Rate prior to Capacity Release Credit (Line 18 / Line 20)		0.24660	
22	Off System Sales and Capacity Release Credit		(0.00664)	
23	PGDC Rate		0.23996	
24	Demand (Over)/Under Collection			
25	Demand E- Factor			
26	(Exhibit No. 1-E)		(13,551,127)	
27	Projected sales for the twelve billing periods of			
28	October, 2026 through September, 2027	1_/	465,805,757	Therms
29	Demand E-Factor (Line 26 / Line 28)		(0.02909)	
30	Total Purchased Gas Cost			
31	PGCC Rate (Line 5)		0.36185	
32	PGDC Rate (Line 23)		0.23996	
33	PGC Rate		0.60181	
34	Currently effective PGC		0.58700	
35	Increase (Decrease) in PGC		0.01481	
36	Net (Over) Under Collection			
37	Commodity E-Factor (Line 11)		0.05245	
38	Demand E-Factor (Line 29)		(0.02909)	
39	E-Factor		0.02336	
40	Currently effective E-Factor		(0.00923)	
41	Increase (Decrease) in E-Factor		0.03259	
42	PGC Rate		0.60181	
43	E-Factor		0.02336	
44	Total Rate		0.62517	
45	Currently effective Rate		0.57777	
46	Increase (Decrease) in Rate		0.04740	

1_/ Includes 81,340,687 Therm Transportation Quantities for the Company's Choice Program

COLUMBIA GAS OF PENNSYLVANIA, INC.
PURCHASED GAS COST RECOVERED UNDER RATES SS
AND COMPUTATION OF DAILY PURCHASED GAS DEMAND
APPLICATION PERIOD: OCTOBER, 2026 THROUGH SEPTEMBER, 2027

Line No.	Description	Detail (1)		Total (2)
1	Total estimated demand charges for the period			
2	October, 2026 through September, 2027	115,897,222		
3	Estimated Demand Quantity (Therms) 1_/	81,748,680		
4	Daily purchased gas demand rate (Line 2 / line 3)	$1.41773	per Therm	
5	Daily purchased gas demand (Therms)	724,680	Therms	
6	Daily purchased gas demand rate per Therm	$1.41773		
7	Total rate SS Daily Demand Cost to be			
8	Recovered (Line 5 x Line 6)			$1,027,401

1_/ Monthly Demand Billing Determinants x 12

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED SALES QUANTITIES AND REVENUES FOR THE PERIOD
SALES AT PGCC AND PGDC RATES
OCTOBER, 2026 THROUGH SEPTEMBER, 2027

Line No.	Month	Sales Subject To PGCC	PGCC Rate 1_/	PGCC Revenue	Sales Subject To PGDC	PGDC Rate 1_/	PGDC Revenue	Purchased Gas Cost Revenue
		(1) Therms	(2) $/Therm	(3=1x2) $	(4) Therms	(5) $/Therm	(6=4x5) $	(7=3+6) $
1	October - 2026	9,166,018	0.36185	3,316,724	11,234,040	0.24660	2,770,314	6,087,038
2	November	24,356,170	0.36185	8,813,280	29,573,119	0.24660	7,292,731	16,106,011
3	December	54,260,170	0.36185	19,634,043	65,931,876	0.24660	16,258,801	35,892,844
4	January - 2027	73,441,376	0.36185	26,574,762	89,006,982	0.24660	21,949,122	48,523,884
5	February	75,099,165	0.36185	27,174,633	90,639,395	0.24660	22,351,675	49,526,308
6	March	62,574,107	0.36185	22,642,441	75,423,955	0.24660	18,599,547	41,241,988
7	April	39,892,503	0.36185	14,435,102	48,115,363	0.24660	11,865,249	26,300,351
8	May	18,899,121	0.36185	6,838,647	23,046,622	0.24660	5,683,297	12,521,944
9	June	9,539,550	0.36185	3,451,886	11,610,534	0.24660	2,863,158	6,315,044
10	July	5,922,540	0.36185	2,143,071	7,282,862	0.24660	1,795,954	3,939,025
11	August	5,487,977	0.36185	1,985,824	6,820,479	0.24660	1,681,930	3,667,754
12	September	5,826,373	0.36185	2,108,273	7,120,530	0.24660	1,755,923	3,864,196
13	Total	384,465,070		139,118,686	465,805,757		114,867,701	253,986,387

1_/ Excludes refunds and experienced over/undercollections

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED SALES QUANTITIES AND REVENUES FOR THE PERIOD
SALES AT STANDBY RATE
OCTOBER, 2026 THROUGH SEPTEMBER, 2027

Line No.	Month	Daily Purchased Gas Demand Quantity (1) Therms	Daily Gas Demand Rate (2) $/Therm	Daily Purchased Gas Demand Revenue (3=1x2) $
1	October - 2026	60,390	1.41773	85,617
2	November	60,390	1.41773	85,617
3	December	60,390	1.41773	85,617
4	January - 2027	60,390	1.41773	85,617
5	February	60,390	1.41773	85,617
6	March	60,390	1.41773	85,617
7	April	60,390	1.41773	85,617
8	May	60,390	1.41773	85,617
9	June	60,390	1.41773	85,617
10	July	60,390	1.41773	85,617
11	August	60,390	1.41773	85,617
12	September	60,390	1.41773	85,617
13	Total	724,680		1,027,401

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED SALES QUANTITIES AND REVENUES FOR THE PERIOD
SALES AT BANKING AND BALANCING RATES
OCTOBER, 2026 THROUGH SEPTEMBER, 2027

Line No.	Month	Lg. Quantity GDS Deliveries	Rate	Revenue	Sm. Quantity GDS Deliveries	Rate	Revenue	Total Trans. Revenue
		(1) Therms	(2) $/Therm	(3=1x2) $	(4) Therms	(5) $/Therm	(6=4x5) $	(7=3+6) $
1	October - 2026	0	0.00226	0	0	0.00697	0	0
2	November	0	0.00226	0	0	0.00697	0	0
3	December	0	0.00226	0	0	0.00697	0	0
4	January - 2027	0	0.00226	0	0	0.00697	0	0
5	February	0	0.00226	0	0	0.00697	0	0
6	March	0	0.00226	0	0	0.00697	0	0
7	April	0	0.00226	0	0	0.00697	0	0
8	May	0	0.00226	0	0	0.00697	0	0
9	June	0	0.00226	0	0	0.00697	0	0
10	July	0	0.00226	0	0	0.00697	0	0
11	August	0	0.00226	0	0	0.00697	0	0
12	September	0	0.00226	0	0	0.00697	0	0
13	Total	0		0	0		0	0

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED TOTAL OVER/UNDERCOLLECTION
FOR THE 2026 1307(f) PERIOD
OCTOBER, 2026 THROUGH SEPTEMBER, 2027

Line No.	Month	Commodity Recoveries PGCC Revenue	Total Commodity Cost of Gas 1_/	Commodity Over/ (Under) collection	Demand Recoveries PGDC Revenue	Total Demand Cost of Gas 1_/	Demand Over/ (Under) collection	Total Over/ (Under) collection
		(1)	(2)	(3=1-2)	(4)	(5)	(6=4-5)	(7=3+6)
		$	$	$	$	$	$	$
1	October - 2026	3,316,724	5,149,605	(1,832,881)	2,855,931	10,861,673	(8,005,742)	(9,838,623)
2	November	8,813,280	13,659,524	(4,846,244)	7,378,348	11,089,029	(3,710,681)	(8,556,925)
3	December	19,634,043	24,947,931	(5,313,888)	16,344,418	11,191,329	5,153,089	(160,799)
4	January - 2027	26,574,762	31,487,557	(4,912,795)	22,034,739	11,191,329	10,843,410	5,930,615
5	February	27,174,633	26,073,590	1,101,043	22,437,292	11,191,329	11,245,963	12,347,006
6	March	22,642,441	20,121,897	2,520,544	18,685,164	11,151,545	7,533,619	10,054,162
7	April	14,435,102	7,942,447	6,492,655	11,950,866	8,283,498	3,667,368	10,160,023
8	May	6,838,647	3,396,386	3,442,261	5,768,914	8,187,498	(2,418,584)	1,023,677
9	June	3,451,886	1,635,173	1,816,713	2,948,775	8,187,498	(5,238,723)	(3,422,010)
10	July	2,143,071	1,539,978	603,093	1,881,571	8,187,498	(6,305,927)	(5,702,834)
11	August	1,985,824	1,387,831	597,993	1,767,547	8,187,498	(6,419,951)	(5,821,958)
12	September	2,108,273	1,778,023	330,250	1,841,540	8,187,498	(6,345,958)	(6,015,709)
13	Total	139,118,686	139,119,942	(1,257)	115,895,102	115,897,222	(2,120)	(3,376)

1_/ Refer to Exhibit 1-B, Schedule No. 1.

Columbia Gas of Pennsylvania, Inc.
Capacity Assignment Factor
Assignment of FT Only

Purchased Gas Demand Charge (PGDC) Paid By the CHOICE Customer
Rates Based on Projected Costs For 12 Months Ending September, 2027

$115,897,222		1. Projected Demand Costs Oct. 2026 through Sept. 2027 (Exh. 1-B, Sch. 1)
(1,027,401)		1a. Less Purchased Gas Demand Costs Recovered Under Rate SS (Exhibit 1-A, Schedule 1, Sheet 2)
0		1b. Less Purchased Gas Demand Allocated to Rates LTS, STS, SGS-TS, and MLS
(13,551,127)		1c. Experienced Demand Net Under/(Over) Collection (Exhibit No. 1-E)
$101,318,694		2. Total Adjusted Demand Costs per 1307(f) Filing (1) + (1a) + (1b) + (1c)
$156.48	per Dth	3. Unit FT Demand Charge Per Dth of TCO/EGTS capacity the marketer would pay TCO and EGTS. (Exhibit 1-A, Schedule 3, Sheet 2)
46,581	MMDth	4. Projected Sales & Choice Requirements for 12 billing periods of October, 2026 through September, 2027
47,242	MMDth	5. Projected Sales & Choice Requirements 12 months ended September 2027, including Unaccounted For @ 1.4%
21,755	MMDth	6. Annual Injections and Withdrawals, Normal Weather
1	Dth	7a. Quantity Delivered to the Customer
1.4%		7b. Unaccounted-for & Co. Use Factor from Volume Balancing System
1.0142	Dth	7c. Quantity Delivered to the City Gate. (7a)/(1-7b)
$2.1751	per Dth	8. Unit Demand Charge: (2) / (4)
($0.0664)	per Dth	9. OSS and Capacity Release Credit
0.0028	Dth	10. Average Daily FT Delivery: (7c) / 365 days
$0.4381	per Dth	11. Annual Demand Charge for the Assigned FT Capacity payable to the pipeline(s): (3) X (10)
$1.7370	per Dth	12. Annual Demand Charge for other capacity that CPA retains (8) - (11)
0.4670	Dth	13. Quantity Injected and Withdrawn to Deliver 1 Dth to the Customer: (6) / (4)
$0.0077		14a. Injection Charge @ $0.0164/Dth
$0.0088		14b. FSS Shrinkage @ 0.543% for gas at $3.4631/Dth
$0.0077		14c. Withdrawal Charge @ $0.0164/Dth
$0.0084		14d. SST Commodity Charge @ $0.0179/Dth
$0.0295		14e. SST retention @ 1.827% for gas at $3.4631/Dth
$0.0621	per Dth	14f. Total Annual Variable Storage Costs
		15. Credit to Purchased Gas Demand Charge for the CHOICE Customer:
$0.4381	per Dth	15a. For Demand Cost Paid to Pipelines: = (11)
($0.0621)	per Dth	15b. Less Storage Costs: = (14f)
$0.3760	per Dth	15c. Net Credit: (15a) + (15b)
$0.03760	per Therm	15d. Per Therm: (15c)/10 - Capacity Assignment Factor
$1.7327	per Dth	16. Purchased Gas Demand Charge Paid By the CHOICE Customer: (8)+(9) - (15c)
$0.17327	per Therm	17. Per Therm: (16)/10

Columbia Gas of Pennsylvania, Inc. (CPA)
CPA Capacity Assignment (PCA): Assignment of FT Capacity Only
CPA Capacity on TCO and EGTS. Cost of the Capacity Allocated to Marketers.

	TCO FT Capacity	EGTS FT Capacity	Total: TCO and EGTS
1. CPA FT Capacity on TCO and EGTS			
2. CPA Contract: Dth/d	132,231	5,000 1/	
3. Projected Demand Costs			
4. Annual Demand Cost 2/	$21,115,311	$356,784	
4a. Monthly Billing Determinants	132,231	5,000	
4b. Annual Demand Charge (4/ 4a)	$159.69	$71.36	
4c. Monthly Demand Charge (4b / number of months)	$13.308	$5.947	
Allocation Capacity and Costs.			
5. Retained Volume:	1.0000	1.0000	
6. Number of Months	12	12	
7. Capacity Allocation	0.9636 3/	0.0364 4/	
8. Unit Annual Cost of City Gate Capacity: (4c) x (5) x (6) x (7) $/Dth	$153.88	$2.60	$156.48

Notes:

1/ Non-storage EGTS FT capacity
2/ Projected demand costs for the period 12 months ended September, 2027.
3/ 132,231/(132,231+5,000) = 0.9636
4/ 5,000/(132,231+5,000) = 0.0364

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
For the Period October 2026 Through September 2027

Line No.	Description	2026 October	November	December	2027 January	February	March	April	May	June	July	August	September	Total
1	Total Quantity													
2	DTH	1,713,000	4,418,000	6,851,000	8,368,000	7,464,000	6,629,000	2,651,000	1,022,000	334,000	306,000	284,000	409,000	40,449,000
3	Total Demand Costs	10,861,673	11,089,029	11,191,329	11,191,329	11,191,329	11,151,545	8,283,498	8,187,498	8,187,498	8,187,498	8,187,498	8,187,498	115,897,222
4	Total Commodity Costs	5,149,605	13,659,524	24,947,931	31,487,557	26,073,590	20,121,897	7,942,447	3,396,386	1,635,173	1,539,978	1,387,831	1,778,023	139,119,942
5	Total Estimated Gas Costs (Line 5 = Line 3 + Line 4)	16,011,278	24,748,553	36,139,260	42,678,886	37,264,919	31,273,442	16,225,945	11,583,884	9,822,671	9,727,476	9,575,329	9,965,521	255,017,164

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Demand Costs

Line No.	Description	2026 October $	November $	December $	2027 January $	February $	March $	April $	May $	June $	July $	August $	September $	Total $
1	Columbia Gas Transmission	9,898,553	9,915,866	9,915,866	9,915,866	9,915,866	9,915,866	7,320,378	7,320,378	7,320,378	7,320,378	7,320,378	7,320,378	103,400,151
2	Texas Eastern Transmission	330,299	330,299	432,599	432,599	432,599	432,599	330,299	330,299	330,299	330,299	330,299	330,299	4,372,788
3	Eastern Gas Transmission and Storage	254,473	296,098	296,098	296,098	296,098	296,098	254,473	254,473	254,473	254,473	254,473	254,473	3,261,801
4	Tennessee Gas	109,401	149,185	149,185	149,185	149,185	109,401	109,401	109,401	109,401	109,401	109,401	109,401	1,471,948
5	National Fuel Gas	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	935,076
6	Equitrans	216,024	344,658	344,658	344,658	344,658	344,658	216,024	120,024	120,024	120,024	120,024	120,024	2,755,458
7	Less Elective Balancing Svc. Credit	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	300,000
8	Total Demand Cost	10,861,673	11,089,029	11,191,329	11,191,329	11,191,329	11,151,545	8,283,498	8,187,498	8,187,498	8,187,498	8,187,498	8,187,498	115,897,222

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Costs

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
1	Term	219,645	2,073,638	5,922,376	6,648,172	5,399,128	2,317,793	238,859	71,487	73,528	82,404	82,859	69,936	23,199,825
2	Spot	9,174,570	5,192,415	12,196,840	13,746,188	9,910,841	1,019,466	13,402,982	11,848,002	10,068,077	10,646,274	9,628,650	7,816,688	114,650,993
3	Local	55,997	64,189	86,882	99,279	80,410	70,160	60,173	59,679	57,893	64,526	64,403	56,419	820,010
4	Storage	(4,278,827)	6,380,102	6,861,953	11,065,198	10,625,791	16,660,358	(5,759,567)	(8,646,432)	(8,751,925)	(9,450,206)	(8,520,071)	(6,309,740)	(123,366)
5	Financial Hedges	(21,780)	(50,820)	(120,120)	(71,280)	57,420	54,120	0	63,650	187,600	196,980	131,990	144,720	572,480
6	Total Commodity Cost	5,149,605	13,659,524	24,947,931	31,487,557	26,073,590	20,121,897	7,942,447	3,396,386	1,635,173	1,539,978	1,387,831	1,778,023	139,119,942

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Quantities

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
	Term													
1	Total-DTH	90,000	702,000	1,415,000	1,415,000	1,276,000	723,000	87,000	28,000	28,000	29,000	29,000	28,000	5,850,000
	Spot													
2	Total-DTH	3,209,000	1,444,000	2,891,000	2,899,000	2,318,000	270,000	4,530,000	4,151,000	3,358,000	3,311,000	2,968,000	2,585,000	33,934,000
	Local													
3	Total-DTH	22,000	21,000	22,000	22,000	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	258,000
	Storage													
4	Total-DTH	(1,608,000)	2,251,000	2,523,000	4,032,000	3,850,000	5,614,000	(1,987,000)	(3,179,000)	(3,073,000)	(3,056,000)	(2,735,000)	(2,225,000)	407,000
	Total - All Sources													
5	Total-DTH	1,713,000	4,418,000	6,851,000	8,368,000	7,464,000	6,629,000	2,651,000	1,022,000	334,000	306,000	284,000	409,000	40,449,000

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Columbia Gas Transmission Corporation

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Columbia Gas Transmission													
	FTS													
1	Billing Determinant-Dth	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	134,931	
2	Less Capacity Release (1)	4,000	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	
3	Net Billing Determinant - Dth	130,931	132,231	132,231	132,231	132,231	132,231	132,231	132,231	132,231	132,231	132,231	132,231	
4	Demand Rate	13.3180	13.3180	13.3180	13.3180	13.3180	13.3180	13.3180	13.3180	13.3180	13.3180	13.3180	13.3180	
5	Demand Cost	1,743,739	1,761,052	1,761,052	1,761,052	1,761,052	1,761,052	1,761,052	1,761,052	1,761,052	1,761,052	1,761,052	1,761,052	21,115,311
	FSS-Reservation													
6	Billing Determinant-Dth	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	
7	Demand Rate	3.8180	3.8180	3.8180	3.8180	3.8180	3.8180	3.8180	3.8180	3.8180	3.8180	3.8180	3.8180	
8	Demand Cost	1,510,836	1,510,836	1,510,836	1,510,836	1,510,836	1,510,836	1,510,836	1,510,836	1,510,836	1,510,836	1,510,836	1,510,836	18,130,032
	FSS-Capacity													
9	Total-DTH	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	21,948,672	
10	Demand Rate	0.0662	0.0662	0.0662	0.0662	0.0662	0.0662	0.0662	0.0662	0.0662	0.0662	0.0662	0.0662	
11	Demand Cost	1,453,002	1,453,002	1,453,002	1,453,002	1,453,002	1,453,002	1,453,002	1,453,002	1,453,002	1,453,002	1,453,002	1,453,002	17,436,024
	SST													
12	Billing Determinant-Dth	395,714	395,714	395,714	395,714	395,714	395,714	197,857	197,857	197,857	197,857	197,857	197,857	
13	Demand Rate	13.1180	13.1180	13.1180	13.1180	13.1180	13.1180	13.1180	13.1180	13.1180	13.1180	13.1180	13.1180	
14	Demand Cost	5,190,976	5,190,976	5,190,976	5,190,976	5,190,976	5,190,976	2,595,488	2,595,488	2,595,488	2,595,488	2,595,488	2,595,488	46,718,784
15	Total TCO Demand Cost	9,898,553	9,915,866	9,915,866	9,915,866	9,915,866	9,915,866	7,320,378	7,320,378	7,320,378	7,320,378	7,320,378	7,320,378	103,400,151

(1) Columbia has included in the application period a projection for the release of 4,000 Dth of capacity to be released at the applicable maximum rate to a large industrial customer on Columbia's system and not subject to recall.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Texas Eastern Transmission Corporation

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	FT1-TCO Delmont													
1	Billing Determinant-Dth	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	3,082	
2	Demand Rate	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	
3	Demand Cost	28,462	28,462	28,462	28,462	28,462	28,462	28,462	28,462	28,462	28,462	28,462	28,462	341,544
	FT1-Uniontown													
4	Billing Determinant-Dth	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	
5	Demand Rate	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	9.2350	
6	Demand Cost	108,539	108,539	108,539	108,539	108,539	108,539	108,539	108,539	108,539	108,539	108,539	108,539	1,302,468
	CDS - Eagle/Rockwood													
7	Billing Determinant-Dth	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	
8	Demand Rate	25.3156	25.3156	25.3156	25.3156	25.3156	25.3156	25.3156	25.3156	25.3156	25.3156	25.3156	25.3156	
9	Demand Cost	59,289	59,289	59,289	59,289	59,289	59,289	59,289	59,289	59,289	59,289	59,289	59,289	711,468
	CDS - Rockwood													
10	Billing Determinant-Dth	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	
11	Demand Rate	21.5114	21.5114	21.5114	21.5114	21.5114	21.5114	21.5114	21.5114	21.5114	21.5114	21.5114	21.5114	
12	Demand Cost	107,557	107,557	107,557	107,557	107,557	107,557	107,557	107,557	107,557	107,557	107,557	107,557	1,290,684
	CDS - Chambersburg													
13	Billing Determinant-Dth	158	158	158	158	158	158	158	158	158	158	158	158	
14	Demand Rate	25.3279	25.3279	25.3279	25.3279	25.3279	25.3279	25.3279	25.3279	25.3279	25.3279	25.3279	25.3279	
15	Demand Cost	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	48,024
16	Billing Determinant-Dth	0	0	10,000	10,000	10,000	10,000	0	0	0	0	0	0	
17	Demand Rate	0.0000	0.0000	10.2300	10.2300	10.2300	10.2300	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
18	Demand Cost	0	0	102,300	102,300	102,300	102,300	0	0	0	0	0	0	409,200
	FT1-MX													
19	Billing Determinant-Dth	100	100	100	100	100	100	100	100	100	100	100	100	
20	Demand Rate	1.7530	1.7530	1.7530	1.7530	1.7530	1.7530	1.7530	1.7530	1.7530	1.7530	1.7530	1.7530	
21	Demand Cost	175	175	175	175	175	175	175	175	175	175	175	175	2,100
	FT1-M2													
22	Billing Determinant-Dth	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	
23	Demand Rate	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	
24	Demand Cost	22,275	22,275	22,275	22,275	22,275	22,275	22,275	22,275	22,275	22,275	22,275	22,275	267,300
25	Total TETCO Demand Cost	330,299	330,299	432,599	432,599	432,599	432,599	330,299	330,299	330,299	330,299	330,299	330,299	4,372,788

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Eastern Gas Transmission and Storage

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Eastern Gas Transmission and Storage													
	GSS - Reservation													
1	Billing Determinant-Dth	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	
2	Demand Rate	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	
3	Demand Cost	64,334	64,334	64,334	64,334	64,334	64,334	64,334	64,334	64,334	64,334	64,334	64,334	772,008
	GSS - Capacity													
4	Billing Determinant-Dth	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	1,871,176	
5	Demand Rate	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	
6	Demand Cost	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	48,276	579,312
	FTNN													
7	Billing Determinant-Dth	0	6,000	6,000	6,000	6,000	6,000	0	0	0	0	0	0	
8	Total-DTH	0.0000	5.9464	5.9464	5.9464	5.9464	5.9464	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Demand Cost	0	35,678	35,678	35,678	35,678	35,678	0	0	0	0	0	0	178,390
	FT													
10	Billing Determinant-Dth	23,857	24,857	24,857	24,857	24,857	24,857	23,857	23,857	23,857	23,857	23,857	23,857	
11	Total-DTH	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	
12	Demand Cost	141,863	147,810	147,810	147,810	147,810	147,810	141,863	141,863	141,863	141,863	141,863	141,863	1,732,091
13	Total Eastern Gas Demand Cost	254,473	296,098	296,098	296,098	296,098	296,098	254,473	254,473	254,473	254,473	254,473	254,473	3,261,801

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Tennessee Gas Pipeline Company

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Tennessee Gas FT-A (Direct) New Castle - 219 Line													
1	Billing Determinant-Dth	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	
2	Demand Rate	4.8056	4.8056	4.8056	4.8056	4.8056	4.8056	4.8056	4.8056	4.8056	4.8056	4.8056	4.8056	
3	Demand Cost	76,890	76,890	76,890	76,890	76,890	76,890	76,890	76,890	76,890	76,890	76,890	76,890	922,680
	Tennessee Gas FT-A (Direct) Pitt Teminal - 219 Line													
4	Billing Determinant-Dth	7,600	16,900	16,900	16,900	16,900	7,600	7,600	7,600	7,600	7,600	7,600	7,600	
5	Demand Rate	4.2778	4.2778	4.2778	4.2778	4.2778	4.2778	4.2778	4.2778	4.2778	4.2778	4.2778	4.2778	
6	Demand Cost	32,511	72,295	72,295	72,295	72,295	32,511	32,511	32,511	32,511	32,511	32,511	32,511	549,268
7	Total Tennessee Gas Demand Cost	109,401	149,185	149,185	149,185	149,185	109,401	109,401	109,401	109,401	109,401	109,401	109,401	1,471,948

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
National Fuel Gas Supply

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	National - FT													
1	Billing Determinant-Dth	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	
2	Demand Rate	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	6.1350	
3	Demand Cost	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	26,405	316,860
	National - EFT													
4	Billing Determinant-Dth	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	
5	Demand Rate	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	6.9865	
6	Demand Cost	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	27,946	335,352
	National - ESS Reservation													
7	Billing Determinant-Dth	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	
8	Demand Rate	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	3.2263	
9	Demand Cost	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	94,044
	National - ESS Capacity													
10	Billing Determinant-Dth	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	
11	Demand Rate	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	0.0589	
12	Demand Cost	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	15,735	188,820
13	Total National Fuel Demand Cost	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	77,923	935,076

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Equitrans

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Equitrans													
	FTS													
1	Billing Determinant-Dth	27,003	26,571	26,571	26,571	26,571	26,571	27,003	15,003	15,003	15,003	15,003	15,003	
2	Demand Rate	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
3	Demand Cost	216,024	212,568	212,568	212,568	212,568	212,568	216,024	120,024	120,024	120,024	120,024	120,024	2,095,008
	FTS													
4	Billing Determinant-Dth	0	18,870	18,870	18,870	18,870	18,870	0	0	0	0	0	0	
5	Demand Rate	0.0000	7.0000	7.0000	7.0000	7.0000	7.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
6	Demand Cost	0	132,090	132,090	132,090	132,090	132,090	0	0	0	0	0	0	660,450
7	Total Equitrans Demand Cost	216,024	344,658	344,658	344,658	344,658	344,658	216,024	120,024	120,024	120,024	120,024	120,024	2,755,458

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Term Contracts

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
	TERM													
	COLUMBIA TRANSMISSION													
1	Quantity - DTH	0	0	457,000	457,000	412,000	0	0	0	0	0	0	0	1,326,000
2	Rate-$/DTH	0.0000	0.0000	4.0406	4.6146	4.1132	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
3	Cost-$	0	0	1,846,554	2,108,872	1,694,638	0	0	0	0	0	0	0	5,650,064
	TEXAS EASTERN													
4	Quantity - DTH	90,000	702,000	726,000	726,000	655,000	723,000	87,000	28,000	28,000	29,000	29,000	28,000	3,851,000
5	Rate-$/DTH	2.4405	2.9539	3.9324	4.4656	4.0496	3.2058	2.7455	2.5531	2.6260	2.8415	2.8572	2.4977	
6	Cost-$	219,645	2,073,638	2,854,922	3,242,026	2,652,488	2,317,793	238,859	71,487	73,528	82,404	82,859	69,936	13,979,585
	TENNESSEE GAS PIPELINE													
7	Quantity - DTH	0	0	232,000	232,000	209,000	0	0	0	0	0	0	0	673,000
8	Rate-$/DTH	0.0000	0.0000	5.2625	5.5917	5.0335	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Cost-$	0	0	1,220,900	1,297,274	1,052,002	0	0	0	0	0	0	0	3,570,176
10	Total - DTH	90,000	702,000	1,415,000	1,415,000	1,276,000	723,000	87,000	28,000	28,000	29,000	29,000	28,000	5,850,000
11	Total Term Commodity													
12	Cost-$	219,645	2,073,638	5,922,376	6,648,172	5,399,128	2,317,793	238,859	71,487	73,528	82,404	82,859	69,936	23,199,825

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Spot and Local Purchases

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
	SPOT													
	Base													
1	Quantity - DTH	1,795,000	506,000	2,891,000	2,899,000	2,318,000	270,000	3,307,000	3,774,000	1,147,000	1,145,000	1,130,000	1,528,000	22,710,000
2	Rate-$/DTH	3.0725	4.2609	4.2189	4.7417	4.2756	3.7758	3.0031	2.8616	3.4380	3.7041	3.7244	3.2259	
3	Cost-$	5,515,138	2,156,015	12,196,840	13,746,188	9,910,841	1,019,466	9,931,252	10,799,678	3,943,386	4,241,195	4,208,572	4,929,175	82,597,746
	Swing													
4	Quantity - DTH	1,414,000	938,000	0	0	0	0	1,223,000	377,000	2,211,000	2,166,000	1,838,000	1,057,000	11,224,000
5	Rate-$/DTH	2.5880	3.2371	0.0179	0.0179	0.0179	0.0179	2.8387	2.7807	2.7701	2.9571	2.9489	2.7318	
6	Cost-$	3,659,432	3,036,400	0	0	0	0	3,471,730	1,048,324	6,124,691	6,405,079	5,420,078	2,887,513	32,053,247
7	Total - DTH	3,209,000	1,444,000	2,891,000	2,899,000	2,318,000	270,000	4,530,000	4,151,000	3,358,000	3,311,000	2,968,000	2,585,000	33,934,000
8	Total Spot													
9	Commodity Cost - $	9,174,570	5,192,415	12,196,840	13,746,188	9,910,841	1,019,466	13,402,982	11,848,002	10,068,077	10,646,274	9,628,650	7,816,688	114,650,993
	Local Direct													
10	Quantity - DTH	22,000	21,000	22,000	22,000	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	258,000
11	Rate-$/DTH	2.5453	3.0566	3.9492	4.5127	4.0205	3.1891	2.8654	2.7127	2.7568	2.9330	2.9274	2.6866	
12	Cost-$	55,997	64,189	86,882	99,279	80,410	70,160	60,173	59,679	57,893	64,526	64,403	56,419	820,010
13	Total - DTH	22,000	21,000	22,000	22,000	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	258,000
14	Total Local													
15	Commodity Cost - $	55,997	64,189	86,882	99,279	80,410	70,160	60,173	59,679	57,893	64,526	64,403	56,419	820,010

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs

Storage

Line No.	Description	2026 October	2026 November	2026 December	2027 January	2027 February	2027 March	2027 April	2027 May	2027 June	2027 July	2027 August	2027 September	Total
	EASTERN - GSS													
1	Injections - DTH	(263,000)	0	0	0	0	0	(238,000)	(226,000)	(226,000)	(228,000)	(226,000)	(226,000)	(1,633,000)
2	Injection Rate - $/Dth	2.8456	3.3827	4.2066	4.7264	4.2585	3.3571	2.9543	2.8515	2.9937	3.2104	3.2381	3.0156	
3	Withdrawals - DTH	0	170,000	276,000	379,000	376,000	376,000	0	0	0	0	0	0	1,577,000
4	Withdrawal Rate - $/Dth	2.8761	2.8761	2.8761	2.8760	2.8761	2.8760	2.8995	2.8831	2.9113	2.9722	3.0137	3.0139	
5	Cost-$	(748,393)	488,937	793,804	1,090,004	1,081,414	1,081,376	(703,123)	(644,439)	(676,576)	(731,971)	(731,811)	(681,526)	(382,304)
6	Injection Rate $/Dth	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	
7	Withdrawal Rate $/Dth	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	0.0254	
8	Cost - $	10,599	4,318	7,010	9,627	9,550	9,550	9,591	9,108	9,108	9,188	9,108	9,108	105,865
	EQUITRANS - SS													
9	Injections - DTH	(268,000)	0	0	0	0	0	0	(270,000)	(272,000)	(272,000)	(272,000)	(270,000)	(1,624,000)
10	Injection Rate - $/Dth	2.8456	3.3827	4.2066	4.7264	4.2585	3.3571	2.9543	2.8515	2.9937	3.2104	3.2381	3.0156	
11	Withdrawals - DTH	0	113,000	334,000	305,000	307,000	550,000	0	0	0	0	0	0	1,609,000
12	Withdrawal Rate - $/Dth	2.8761	2.8761	2.8761	2.8760	2.8761	2.8760	2.8995	2.8831	2.9113	2.9722	3.0137	3.0139	
13	Cost-$	(762,621)	324,999	960,617	877,180	882,963	1,581,800	0	(769,905)	(814,286)	(873,229)	(880,763)	(814,212)	(287,457)
14	Inject/With. Rate $/DTH	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	
15	Cost - $	1,849	780	2,305	2,105	2,118	3,795	0	1,863	1,877	1,877	1,877	1,863	22,309
	TCO - FSS													
16	Injections - DTH	(1,317,000)	0	0	0	0	0	(1,789,000)	(3,020,000)	(3,020,000)	(3,022,000)	(2,702,000)	(2,162,000)	(17,032,000)
17	Injection Rate - $/Dth	2.8456	3.3827	4.2066	4.7264	4.2585	3.3571	2.9543	2.8515	2.9937	3.2104	3.2381	3.0156	
18	Withdrawals - DTH	0	2,195,000	2,529,000	4,220,000	3,918,000	4,170,000	0	0	0	0	0	0	17,032,000
19	Withdrawal Rate - $/Dth	2.8761	2.8761	2.8761	2.8760	2.8761	2.8760	2.8995	2.8831	2.9113	2.9722	3.0137	3.0139	
20	Cost-$	(3,747,655)	6,313,040	7,273,657	12,136,720	11,268,560	11,992,920	(5,285,243)	(8,611,530)	(9,040,974)	(9,701,829)	(8,749,346)	(6,519,727)	(2,671,407)
21	Inject/With. Rate $/DTH	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164	
22	Cost - $	21,599	35,998	41,476	69,208	64,255	68,388	29,340	49,528	49,528	49,561	44,313	35,457	558,651
	NATIONAL FUEL - ESS													
23	Injections - DTH	(6,000)	0	0	0	0	0	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(42,000)
24	Injection Rate - $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.9543	2.8515	2.9937	3.2104	3.2381	3.0156	
25	Withdrawals - DTH	0	1,000	2,000	0	2,000	34,000	0	0	0	0	0	0	39,000
26	Withdrawal Rate - $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.8995	2.8831	2.9113	2.9722	3.0137	3.0139	
27	Cost-$	0	0	0	0	0	0	(17,726)	(17,109)	(17,962)	(19,262)	(19,429)	(18,094)	(109,582)
28	Inject/With. Rate $/DTH	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	
29	Cost - $	238	40	79	0	79	1,346	238	238	238	238	238	238	3,210
30	Quantity - DTH	(1,854,000)	2,479,000	3,141,000	4,904,000	4,603,000	5,130,000	(2,033,000)	(3,522,000)	(3,524,000)	(3,528,000)	(3,206,000)	(2,664,000)	(74,000)
31	Total Purchase Cost	(5,258,669)	7,126,976	9,028,078	14,103,904	13,232,937	14,656,096	(6,006,092)	(10,042,983)	(10,549,798)	(11,326,291)	(10,381,349)	(8,033,559)	(3,341,168)
32	Total Inject/With. Cost	34,285	41,136	50,870	80,940	76,002	83,079	39,169	60,737	60,751	60,864	55,536	46,666	686,825

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Storage Transportation Charges

Line No.	Description	2026 October	November	December	2027 January	February	March	April	May	June	July	August	September	Total
	TCO - SST													
1	Injections - DTH	(1,317,000)	0	0	0	0	0	(1,789,000)	(3,020,000)	(3,020,000)	(3,022,000)	(2,702,000)	(2,162,000)	(17,032,000)
2	Withdrawals - DTH	0	2,195,000	2,529,000	4,220,000	3,918,000	4,170,000	0	0	0	0	0	0	17,032,000
3	Trans. Chrg. $/Dth	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	
4	Cost-$	23,574	39,291	45,269	75,538	70,132	74,643	32,023	54,058	54,058	54,094	48,366	38,700	609,746
	EASTERN - GSS													
5	Injections - DTH	(263,000)	0	0	0	0	0	(238,000)	(226,000)	(226,000)	(228,000)	(226,000)	(226,000)	(1,633,000)
6	Withdrawals - DTH	0	170,000	276,000	379,000	376,000	376,000	0	0	0	0	0	0	1,577,000
7	Trans. Chrg. $/Dth	0.0179	0.1090	0.1090	0.1090	0.1090	0.1090	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	
8	Cost-$	4,708	18,530	30,084	41,311	40,984	40,984	4,260	4,045	4,045	4,081	4,045	4,045	201,122
	EQUITRANS - SS													
9	Injections - DTH	(268,000)	0	0	0	0	0	0	(270,000)	(272,000)	(272,000)	(272,000)	(270,000)	(1,624,000)
10	Withdrawals - DTH	0	113,000	334,000	305,000	307,000	550,000	0	0	0	0	0	0	1,609,000
11	Trans. Chrg. $/Dth	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
12	Cost-$	3,082	1,300	3,841	3,508	3,531	6,325	0	3,105	3,128	3,128	3,128	3,105	37,181
	NATIONAL FUEL													
13	Injections - DTH	(6,000)	0	0	0	0	0	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(42,000)
14	Withdrawals - DTH	0	1,000	2,000	0	2,000	34,000	0	0	0	0	0	0	39,000
15	Trans. Chrg. $/Dth	0.0259	0.0259	0.0259	0.0259	0.0259	0.0259	0.0259	0.0259	0.0259	0.0259	0.0259	0.0259	
16	Cost-$	155	26	52	0	52	881	155	155	155	155	155	155	2,096
17	Total Storage - DTH	(1,854,000)	2,479,000	3,141,000	4,904,000	4,603,000	5,130,000	(2,033,000)	(3,522,000)	(3,524,000)	(3,528,000)	(3,206,000)	(2,664,000)	(74,000)
18	Total EUB - DTH	246,000	(228,000)	(618,000)	(872,000)	(753,000)	484,000	46,000	343,000	451,000	472,000	471,000	439,000	481,000
19	Total DTH	(1,608,000)	2,251,000	2,523,000	4,032,000	3,850,000	5,614,000	(1,987,000)	(3,179,000)	(3,073,000)	(3,056,000)	(2,735,000)	(2,225,000)	407,000
20	Total Purchase Cost	(5,258,669)	7,126,976	9,028,078	14,103,904	13,232,937	14,656,096	(6,006,092)	(10,042,983)	(10,549,798)	(11,326,291)	(10,381,349)	(8,033,559)	(3,450,750)
21	Total Choice Bank Cost	914,038	(847,157)	(2,296,241)	(3,240,003)	(2,797,847)	1,798,350	170,918	1,274,451	1,675,736	1,753,763	1,750,048	1,631,148	1,787,204
22	Total Inject/With. Cost	34,285	41,136	50,870	80,940	76,002	83,079	39,169	60,737	60,751	60,864	55,536	46,666	690,035
23	Total Transp. Charge	31,519	59,147	79,246	120,357	114,699	122,833	36,438	61,363	61,386	61,458	55,694	46,005	850,145
24	Total Storage Cost	(4,278,827)	6,380,102	6,861,953	11,065,198	10,625,791	16,660,358	(5,759,567)	(8,646,432)	(8,751,925)	(9,450,206)	(8,520,071)	(6,309,740)	(123,366)

COLUMBIA STATEMENT NO. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2026-3060762
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF

NICOLE PALONEY

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nicole Paloney, and my business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

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

A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or the "Company") as Director of Rates and Regulatory Affairs.

Q. What are your responsibilities as Director of Rates and Regulatory Affairs?

A. I am responsible for developing and directing rate activity on behalf of the Company before the Pennsylvania Public Utility Commission ("Commission") as well as coordinating and representing the Company's position in a variety of regulatory matters and proceedings.

Q. What is your educational and professional background?

A. I have a Bachelor of Science in Business and Administration with an emphasis in Accounting and Finance from The Ohio State University. In 1998, I was hired as a staff auditor for Deloitte, primarily serving middle market clients in a variety of industries, including manufacturing, public pension systems and not for profit clients. I was promoted to manager in 2004 and served in that capacity until I left Deloitte in July 2005. From August 2005 until August 2008, I was employed by Cardinal Health in Dublin, Ohio. Cardinal Health provides pharmaceutical and medical products to the Health Care industry and is also a manufacturer of medical and surgical products. I was a manager in Internal Audit during my

tenure at Cardinal, with responsibility over internal audits that took place in the manufacturing and corporate segments of the company.

In August 2008, I joined NiSource Corporate Services Company ("NCSC") as an Internal Audit Manager, with responsibility for internal audits that took place in NiSource Inc.'s Gas Distribution segment. In September 2011, I transitioned to the Regulatory Strategy and Support group in the role of Project Manager, providing support to the state regulatory teams in Pennsylvania and Maryland. In May 2014, I began my role as Director of Rates and Regulatory Affairs for the Company, until April 2019 when I took a temporary assignment in the NCSC legal department, providing business support to the legal team in Massachusetts. I returned to my role as Columbia's Director of Rates and Regulatory Affairs in November 2019.

Q. Have you testified before this or any other Commission?

A. Yes. I have testified before this Commission on behalf of Columbia in Company base rate proceedings at Docket Nos. R-2015-2468056, R-2016-2529660, R-2018-2647577, R-2021-3024296, R-2022-3031211 R-2024-3046519 and R-2025-3053499. I have also testified before this Commission in the Company's Purchased Gas Cost ("PGC") proceedings at Docket Nos. R-2020-3018993, R-2021-3024349, R-2022-3031172, R-2023-3038630 R-2024-3047014 and R-2025-3053663. I also have testified before the Maryland Public Service Commission on behalf of Columbia Gas of Maryland, Inc. as a cost of service witness in Case No. 9316 and as a policy witness in Case Nos. 9354, 9480, 9680, and 9754.

Q. Please describe the scope of your testimony in this proceeding.

A. I am responsible for the overall presentation of Columbia's case in this PGC proceeding. Additionally, I am responsible for Exhibit 1, which sets forth the proposed tariff filed in this proceeding. I am also responsible for Exhibit 7, filed in response to the Commission's requirement that the Company provide a list of agreements that exist between Columbia and other utilities, pipelines or jurisdictional customers to transport gas through its system. I am also sponsoring Exhibit 9, submitted in response to the Commission's regulations that require the Company to provide a schedule depicting historic monthly end-user transportation throughput (known on Columbia's system as CHOICE Service and General Distribution Service) by customer, and Exhibit 11, which provides a detailed explanation of each rate structure or rate allocation change proposed in the filing. Exhibit NP-1, attached to my testimony, is proposed Tariff Supplement No. 415, which contains the rate changes identified by Columbia Witness Matthew Vorndran in Columbia Statement No. 2.

II. SPONSORED EXHIBITS

Q. Were the exhibits that you are sponsoring prepared by you or by persons working under your direction?

A. Yes, they were.

Q. Is the information contained within the exhibits that you are sponsoring true and correct to the best of your knowledge and belief?

A. Yes, it is.

Q. Please describe briefly the area Columbia serves in the Commonwealth.

A. Columbia is engaged in the business of furnishing natural gas distribution service to more than 448,000 customers pursuant to certificates of public convenience issued by the Commission. Columbia provides service to 450 communities in 26 counties in western and south-central Pennsylvania.

Q. Please identify the scope of the testimony of the Company's other witnesses in this proceeding.

A. In Columbia Statement No. 1, Tina Monnig, Manager of Supply and Capacity Management with NCSC, testifies regarding the Company's gas supply plan, which includes information in support of the Company's least cost procurement strategy as contained in Exhibit 5. Ms. Monnig also testifies regarding the Company's involvement in relevant Federal Energy Regulatory Commission proceedings in support of Exhibit 3. Further, Ms. Monnig is supporting Exhibit 2, Exhibit 4, Exhibit 10, and Exhibits 12 through 15.

In Columbia Statement No. 2, Matthew Vorndran, Senior Regulatory Analyst with NCSC, testifies regarding Exhibits 1-A through 1-F, which are filed to comply with Commission requirements in Title 52 of Pennsylvania Code Sections 53.64, *et seq*.

In Columbia Statement No. 4, Patrick Pluard, Director of Portfolio Optimization, supports Exhibits 1-D-1 through 1-D-3, Exhibit 6, and Exhibits 8-A through 8-E. Mr. Pluard also discusses the Company's gas purchasing and procurement strategies to acquire the least cost reliable gas supplies to serve its

customers, the Company's Unified Sharing Mechanism, and an update on the hedging program approved in the Company's 2023 PGC proceeding (Docket No. R-2023-3038630).

Q. Please explain Exhibit 1.

A. Exhibit 1 sets forth that the proposed tariff filed in this proceeding for recovery of purchased gas costs beginning October 1, 2026, will be submitted with testimony and is attached hereto as Exhibit NP-1. The tariff includes the proposed rates for each rate schedule, a PGC Rider that describes the manner in which the Company will recover its purchased gas costs from sales customers, and rates associated with standby service.

Q. Turning to Exhibit 7, would you please describe that exhibit?

A. Exhibit 7 was included in the pre-filing data submitted by Columbia in this proceeding on February 27, 2026. It was submitted in accordance with § 53.64(c)(8) of the Commission's regulations, which requires the Company to provide:

> A list of agreements to transport gas by the utility through its system, for other utilities, pipelines, or jurisdictional customers including the quantity and price of said transportation.

As noted in Exhibit 7, Columbia does not presently transport gas for other utilities or interstate pipelines.

Q. Please describe Exhibit 9.

A. Exhibit 9 provides a summary of transportation throughput, by customer, by month. This exhibit is submitted in compliance with § 53.64(c)(9) of the Commission's regulations, which requires the Company to provide a schedule

depicting historic monthly end-user transportation throughput. Exhibit 9, Schedule 1 shows the throughput for CHOICE[SM] customers by rate schedule by month for the period February 1, 2025, through January 31, 2026. Exhibit 9, Schedule 2 shows throughput for General Distribution Service, which represents commercial and industrial customers purchasing their gas supply from marketers by month and by rate schedule for the same period.

Q. Please explain Exhibit 11.

A. Exhibit 11 is submitted pursuant to § 53.64(c)(11) of the Commission's regulations, which requires the Company to detail rate structure or rate allocation changes proposed in the filing. As noted in Exhibit 11, Columbia has not proposed any rate structure or rate allocation changes in this filing.

III. PIPELINE PENALTY CREDITS AND REFUNDS

Q. Please explain the ratemaking treatment of pipeline penalty credits and pipeline refunds.

A. As a result of a variety of Commission orders issued prior to 2018, Columbia had been permitted to use the residential portion of certain pipeline penalty credits and refunds to help fund its Hardship Fund. Pursuant to the Commission Order issued June 14, 2018, in Docket No. P-2018-3000160, Columbia was granted approval on an ongoing basis to use the residential portion of pipeline penalty credits and refunds received as a funding source for the Hardship Fund. The June 14, 2018 Order provides that if the balance of the Hardship Fund exceeds $750,000, then the residential portion of pipeline penalty credits and refunds received will flow through the PGC until the balance falls below $750,000. From

March 14, 2024, through November 30, 2025, the Company's Hardship Fund balance fell below the $750,000 cap. Therefore, during that time, the residential portion of penalty credits and refunds received were allocated to the Hardship Fund, and the non-residential portion of pipeline penalty credits and refunds received flowed through to non-residential customers through rates filed in the quarterly PGC filings. In December 2025, Columbia received a rate refund, as well as a penalty credit from Columbia Gas Transmission LLC ("TCO") which has enabled the Company to fully fund the Hardship Fund. The relating entries were booked in February 2026. A $375,000 payment to the Dollar Energy Fund from the Company's Hardship Fund is planned for March 2026. Once the payment is complete, $375,000 more will be allocated from the TCO refund to the Company's Hardship Fund to bring it back to its $750,000 cap level. Starting February 26, 2026, all residential and non-residential penalty credits and refunds received will be distributed to customers through rates filed in the quarterly PGC filing. See Table 1 below for the recent pipeline penalty credits and pipeline refunds received by Columbia, the month and year they were received, the original dollar amount recorded and their disposition.

Table 1

Pipeline Penalty Credits and Refunds Received

Columbia Gas of Pennsylvania, Inc.

Docket	Date Received	Amount	Hardship Fund	Non-Residential
April 1, 2025 PGC Filing				
Columbia Gas Transmission, LLC: Penalty Credit Docet No. RP25-00278	January 2025	18,406	13,329	5,077
Texas Eastern Transmission: Penalty Credit	January 2025	46	33	13
		18,452	13,362	5,090

Docket	Date Received	Amount	Hardship Fund	Non-Residential
October 1, 2025 PGC Filing				
Eastern Gas and Transmission: Penalty Credit Docket No. RP00395000	July 2025	6,503	4,695	1,808
Texas Eastern Transmission: Penalty Credit Docket No. RP00395000	August 2025	1,865	1,347	519
		8,369	6,042	2,326

Docket	Date Received	Amount	Hardship Fund	Non-Residential	Residential
April 1, 2026 PGC Filing					
Columbia Gas Transmission, LLC: Supplier Refund Docket No. RP24-1103	December 2025	10,048,637	1,100,925 1/	2,793,377	6,154,334
Columbia Gas Transmission, LLC: Penalty Credit Docket RP26-300	December 2025	63,177	-	17,562	45,614
Texas Eastern Transmission: Penalty Credit	December 2025	153	-	42	110
		10,111,966	1,100,925	2,810,982	6,200,059

1/ $725,925.08 was allocated to the Hardship Fund in February 2026. After the $375,000 payment to the Dollar Energy Fund in March 2026, an additional $375,000 additional will be allocated to the Hardship Fund to reach the cap ($725,925 + $375,000 = $1,100,925).

The penalty credits and supplier refunds in the April 1, 2025, PGC filing totaled $18,452. The residential portion was allocated to the Hardship Fund while the non-residential portion flowed through to customers as shown for the period of April 2025 through March 2026. The penalty credits and supplier refunds in the October 1, 2025, PGC filing totaled $8,369. The residential portion was allocated to the Hardship Fund while the non-residential portion flowed through to customers as shown for the period of October 2025 through September 2026. As mentioned above, the Company received a supplier refund and two penalty credits totaling $10,111,966 at the end of 2025. There will be a portion allocated to the Hardship Fund, along with additional residential and non-residential portions that will be flowed through to customers in April 1, 2026, quarterly PGC filing.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Supplement No. 415 to
Tariff Gas – Pa. P.U.C. No. 9

COLUMBIA GAS OF PENNSYLVANIA, INC.

121 Champion Way, Suite 100 **Canonsburg, Pennsylvania**

RATES AND RULES

FOR

FURNISHING GAS SERVICE

IN

THE TERRITORY AS DESCRIBED HEREIN

ISSUED: April 1, 2026 EFFECTIVE: October 1, 2026

ISSUED BY: MARK KEMPIC, PRESIDENT
121 CHAMPION WAY, SUITE 100
CANONSBURG, PENNSYLVANIA 15317

NOTICE

This Tariff Supplement Makes Changes to the Existing Tariff - See List of Changes Made by This Tariff Supplement on Page Nos. 2 and 2a.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
Cover	Tariff Cover Page	Supplement No., Issued and Effective Date.
2-2a	List of Changes	List of Changes.
16	Rate Summary	The “Gas Supply Charge” increased. The “Gas Cost Adjustment” increased. The “Pass-through Charge” increased. The “Total Effective Rate” for RSS and RDS increased.
17	Rate Summary	The “Gas Supply Charge” increased. The “Gas Cost Adjustment” increased. The “Pass-through Charge” increased. The “Total Effective Rate” for SGSS, SCD and SGDS increased.
18	Rate Summary	The “Gas Supply Charge” increased. The “Gas Cost Adjustment” increased. The “Pass-through Charge” increased. The “Total Effective Rate” increased for LGSS.
19	Rate Summary	The “Gas Supply Charge” increased. The “Gas Cost Adjustment” increased. The “Pass-through Charge” increased. The “Total Effective Rate” increased for MLSS.
20	Rate Summary	The “Residential Price-to-Compare” and “Commercial Price-to-Compare” increased. The “Rate SS – Standby Service” decreased.
21	Rider Summary	The “Merchant Function Charge – Rider MFC” increased.
21a	Gas Supply Charge Summary	The “PGCC” increased. The “Rider MFC” increased. The “Total Gas Supply Charge” increased.

Supplement No. 415 to
Tariff Gas – Pa. P.U.C. No. 9
One Hundred Thirty-seventh Revised Page No. 2a
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Thirty-sixth Revised Page No. 2a**

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
21b	Pass-through Charge Summary	The “PGDC” increased. The “PGDC E-Factor” increased. The “Capacity Assignment Factor” decreased. The “Total Pass-through Charge” increased.
21c	Price-to-Compare Summary	The “PGCC” increased. The “Gas Cost Adjustment” increased. The “Capacity Assignment Factor” increased. The “Rider MFC” increased. The “Total Price-to-Compare” increased.
151	Rider PGC	The Purchased Gas Commodity Cost, made up of the Commodity Cost and the Commodity "E" Factor increased. The Commodity Cost increased. The Demand Cost increased. The Purchased Gas Demand Cost billed to Rate SGDS increased. The Purchased Gas Demand Cost billed to Rate RDS and Rate SCD increased. The Capacity Assignment Factor credited to Rate RDS and Rate SCD decreased.
154	Rider PGC	The Purchased Gas Demand Cost billed to Rate RDS and Rate SCD increased. The Capacity Assignment Factor credited to Rate RDS and Rate SCD increased.

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
Two Hundred Thirty-fourth Revised Page No. 16
Columbia Gas of Pennsylvania, Inc. **Canceling Two Hundred Thirty-third Revised Page No. 16**

Rate Summary

Rate per thm

Residential Rate Schedules		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-Through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Rider EE-Energy Efficiency Rider 5/	Total Effective Rate
Rate RSS - Residential Sales Service									
Customer Charge	$	20.15				0.00	0.01	-	20.16
Usage Charge	$	1.09952	0.36868	0.05245	0.33030	0.00000	0.00055	0.00613	1.85763
Rate RDS - Residential Distribution Service									
Customer Charge	$	20.15				0.00	0.01	-	20.16
Usage Charge:									
Customers Electing CHOICE	$	1.09952	-	-	0.29270	0.00000	0.00055	0.00613	1.39890

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ The DSIC percentage is reflected on Page No. 21 and is applied to the Customer Charge and the Distribution Charge.
5/ Rider EE is reflected on Page No. 21 and is applied to the Distribution Charge.

Issued: April 1, 2026 **Effective: October 1, 2026**

Mark Kempic - President

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Forty-fifth Revised Page No. 17
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Forty-fourth Revised Page No. 17**

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules <= 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Rider EE-Energy Efficiency Rider 5/	Total Effective Rate	
Rate SGSS - Small General Sales Service										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	36.55				0.00	0.02	-	36.57	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	69.85				0.00	0.03	-	69.88	
Usage Charge										
Annual Throughput <= 6,440 thm	$	0.89205	0.36448	0.05245	0.18773	0.00000	0.00045	0.00343	1.50059	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.76032	0.36448	0.05245	0.18773	0.00000	0.00038	0.00343	1.36879	
Rate SCD - Small Commercial Distribution										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	36.55				0.00	0.02	-	36.57	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	69.85				0.00	0.03	-	69.88	
Usage Charge: Customers Electing CHOICE										
Annual Throughput <=6,440 thm	$	0.89205	-	-	0.15013	0.00000	0.00045	0.00343	1.04606	
Annual Throughput >6,440 and <=64,400 thm	$	0.76032	-	-	0.15013	0.00000	0.00038	0.00343	0.91426	
Rate SGDS - Small General Distribution Service										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	36.55				0.00	0.02	-	36.57	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	69.85				0.00	0.03	-	69.88	
Usage Charge - Priority One										
Annual Throughput <= 6,440 thm	$	0.87922	-	-	0.18773	0.00000	0.00044	0.00343	1.07082	6/
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.74748	-	-	0.18773	0.00000	0.00037	0.00343	0.93901	6/
Usage Charge - Non-Priority One										
Annual Throughput <= 6,440 thm	$	0.87922	-	-	0.00010	0.00000	0.00044	0.00343	0.88319	6/
Annual Throughput > 6,440 and <= 64,400 thm	$	0.74748	-	-	0.00010	0.00000	0.00037	0.00343	0.75138	6/

1/ Please see Page No. 21a for rate components.
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4/ The DSIC percentage is reflected on Page No. 21 and is applied to the Customer Charge and the Distribution Charge.
5/ Rider EE is reflected on Page No. 21 and is applied to the Distribution Charge.
6/ Plus Rider EBS Option 1 or 2 - See Page 21.

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Mark Kempic - President

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Seventy-ninth Revised Page No. 18
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Seventy-eighth Revised Page No. 18**

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules > 64,400 therms - 12 Months Ending October	Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Total Effective Rate	
Rate LGSS - Large General Sales Service								
Customer Charge:								
Annual Throughput > 64,400 thm and <= 110,000 thm	$ 335.90				0.00	0.17	336.07	
Annual Throughput > 110,000 thm and <= 540,000 thm	$ 1,523.60				0.00	0.76	1,524.36	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$ 4,082.25				0.00	2.04	4,084.29	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$ 6,349.60				0.00	3.17	6,352.77	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$ 12,245.05				0.00	6.12	12,251.17	
Annual Throughput > 7,500,000 thm	$ 18,140.45				0.00	9.07	18,149.52	
Usage Charge:								
Annual Throughput > 64,400 thm and <= 110,000 thm	$ 0.57443	0.36298	0.05245	0.18763	0.00000	0.00029	1.17778	
Annual Throughput > 110,000 thm and <= 540,000 thm	$ 0.53705	0.36298	0.05245	0.18763	0.00000	0.00027	1.14038	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$ 0.32026	0.36298	0.05245	0.18763	0.00000	0.00016	0.92348	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$ 0.28406	0.36298	0.05245	0.18763	0.00000	0.00014	0.88726	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$ 0.25490	0.36298	0.05245	0.18763	0.00000	0.00013	0.85809	
Annual Throughput > 7,500,000 thm	$ 0.15169	0.36298	0.05245	0.18763	0.00000	0.00008	0.75483	
Rate SDS - Small Distribution Service								
Customer Charge:								
Annual Throughput > 64,400 thm and <= 110,000 thm	$ 335.90				0.00	0.17	336.07	
Annual Throughput > 110,000 thm and <= 540,000 thm	$ 1,523.60				0.00	0.76	1,524.36	
Usage Charge:								
Annual Throughput > 64,400 thm and <= 110,000 thm	$ 0.57443	-	-	-	0.00000	0.00029	0.57472	5/
Annual Throughput > 110,000 thm and <= 540,000 thm	$ 0.53705	-	-	-	0.00000	0.00027	0.53732	5/
Rate LDS - Large Distribution Service								
Customer Charge:								
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$ 4,082.25				0.00	2.04	4,084.29	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$ 6,349.60				0.00	3.17	6,352.77	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$ 12,245.05				0.00	6.12	12,251.17	
Annual Throughput > 7,500,000 thm	$ 18,140.45				0.00	9.07	18,149.52	
Usage Charge:								
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$ 0.32026	-	-	-	0.00000	0.00016	0.32042	5/
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$ 0.28406	-	-	-	0.00000	0.00014	0.28420	5/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$ 0.25490	-	-	-	0.00000	0.00013	0.25503	5/
Annual Throughput > 7,500,000 thm	$ 0.15169	-	-	-	0.00000	0.00008	0.15177	5/

1/ Please see Page No. 21a for rate components.
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4/ The DSIC percentage is reflected on Page No. 21 and is applied to the Customer Charge and the Distribution Charge.
5/ Plus Rider EBS Option 1 or 2 - See Page 21.

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Mark Kempic - President

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred-sixth Revised Page No. 19
Canceling One Hundred-fifth Revised Page No. 19

Columbia Gas of Pennsylvania, Inc.

Rate Summary

Rate per thm

Main Line Service Rate Schedules Commercial / Industrial		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Total Effective Rate	
Rate MLSS - Main Line Sales Service									
Customer Charge:									
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	0.23	469.57	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	0.57	1,149.57	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	1.03	2,051.03	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	2.05	4,098.05	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	3.66	7,325.66	
Usage Charge:									
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	0.36298	0.05245	0.18763	0.00000	0.00000	0.61243	
MLS Class II:									
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04481	0.36298	0.05245	0.18763	0.00000	0.00002	0.64789	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03876	0.36298	0.05245	0.18763	0.00000	0.00002	0.64184	
Annual Throughput > 7,500,000 thm	$	0.03355	0.36298	0.05245	0.18763	0.00000	0.00002	0.63663	
Rate MLDS - Main Line Distribution Service									
Customer Charge:									
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	0.23	469.57	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	0.57	1,149.57	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	1.03	2,051.03	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	2.05	4,098.05	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	3.66	7,325.66	
Usage Charge:									
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	-	-	-	0.00000	0.00000	0.00937	5/
MLS Class II:									
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04481	-	-	-	0.00000	0.00002	0.04483	5/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03876	-	-	-	0.00000	0.00002	0.03878	5/
Annual Throughput > 7,500,000 thm	$	0.03355	-	-	-	0.00000	0.00002	0.03357	5/

1/ Please see Page No. 21a for rate components.
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5/ Plus Rider EBS Option 1 or 2 - See Page 21.

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Mark Kempic - President

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Fifty-eighth Revised Page No. 20
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Fifty-seventh Revised Page No. 20**

Other Rates Summary

Rate per thm

Description		Rate $/ thm		Applicable Rate Schedules
Penalty Credit/Pipeline Refund Passback - Residential		(0.02034)	1/	RSS/RDS/CAP
Penalty Credit/Pipeline Refund Passback - Non-Residential	$	(0.02324)	2/	SGSS/SGDS-P1/SCD/LGSS/MLSS
Price to Compare for Residential Gas Supply	$	0.45873	3/	RSS
Price to Compare for Commercial Gas Supply	$	0.45453	3/	SGSS (< = 64,400 thms)
State Tax Adjustment Surcharge Percentage		0.000%		Customer and Distribution Charges on all rates
Rate SS - Standby Service	$	1.41773		Per therm based on a customer's Maximum Daily Firm Requirement. See Pages 134 - 136 herein for detail.

1/ Penalty Credit and Pipeline Refund passback rate of ($0.02034) effective April 2026-March 2027
2/ Penalty Credit and Pipeline Refund passback rate of ($0.00002) effective October 2025-September 2026 and Penalty Credit and Pipeline Refund passback rate of ($0.02322) effective April 2026-March 2027
3/ Please see Page No. 21c for rate components.

Issued: April 1, 2026 **Effective: October 1, 2026**

Mark Kempic - President

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
Two Hundred Fifty-third Revised Page No. 21
Columbia Gas of Pennsylvania, Inc. **Canceling Two Hundred Fifty-second Revised Page No. 21**

Rider Summary

Riders	Rate	Applicable Rate Schedules
Customer Choice - Rider CC	$ 0.00010 /thm	RSS/RDS/SGSS/SGDS/SCD/DGDS
Universal Service Plan - Rider USP	$ 0.13967 /thm	RSS/RDS
Distribution System Improvement Charge - Rider DSIC	0.05%	This percentage is applied to the Distribution Charge and the Customer Charge. See Pages 177-180a for Rider DSIC details.
Elective Balancing Service - Rider EBS:		
Option 1 - Small Customer	$ 0.01452 /thm	SGDS/SDS
Option 1 - Large Customer	$ 0.00756 /thm	LDS/MLDS
Option 2 - Small Customer	$ 0.00697 /thm	SGDS/SDS
Option 2 - Large Customer	$ 0.00226 /thm	LDS/MLDS
Gas Procurement Charge - Rider GPC	$ 0.00113 /thm	RSS/SGSS/LGSS/MLSS
Merchant Function Charge - Rider MFC	$ 0.00570 /thm	RSS
Merchant Function Charge - Rider MFC	$ 0.00150 /thm	SGSS
Purchased Gas Cost - Rider PGC	Pg. 21a & 21b	Rate Schedules specified on Page 21a & 21b
Energy Efficiency Rider - Rider EE	$ 0.00613 /thm	RSS/RDS
Energy Efficiency Rider - Rider EE	$ 0.00343 /thm	SGSS/SCD/SGDS
State Tax Adjustment Surcharge Percentage	0.000%	Customer and Distribution Charges on all rates

Issued: April 1, 2026 **Effective: October 1, 2026**

Mark Kempic - President

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
Seventy-eighth Revised Page No. 21a

Columbia Gas of Pennsylvania, Inc.

Canceling Seventy-seventh Revised Page No. 21a

Gas Supply Charge Summary

Rate per thm

Rate Schedule		PGCC	Rider GPC	Rider MFC	Total Gas Supply Charge
Rate CAP - Customer Assistance Plan	$	0.36185	0.00113	0.00570	0.36868
Rate RSS - Residential Sales Service	$	0.36185	0.00113	0.00570	0.36868
Rate SGSS - Small General Sales Service	$	0.36185	0.00113	0.00150	0.36448
Rate LGSS - Large General Sales Service	$	0.36185	0.00113	-	0.36298
Rate MLSS - Main Line Sales Service	$	0.36185	0.00113	-	0.36298

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Mark Kempic - President

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Thirtieth Revised Page No. 21b
Columbia Gas of Pennsylvania, Inc.
Canceling One Hundred Twenty-ninth Revised Page No. 21b

Pass-through Charge Summary
Rate per thm

Rate Schedule		PGDC	PGDC "E" Factor	Capacity Assignment Factor	Pipeline Refund/ Penalty Credits	Rider CC	Rider USP	Total Pass-through Charge
Rate CAP - Customer Assistance Plan	$	0.23996	(0.02909)	-	(0.02034)	-	-	0.19053
Rate RSS - Residential Sales Service	$	0.23996	(0.02909)	-	(0.02034)	0.00010	0.13967	0.33030
Rate SGSS - Small General Sales Service	$	0.23996	(0.02909)	-	(0.02324)	0.00010	-	0.18773
Rate LGSS - Large General Sales Service	$	0.23996	(0.02909)	-	(0.02324)	-	-	0.18763
Rate MLSS - Main Line Sales Service	$	0.23996	(0.02909)	-	(0.02324)	-	-	0.18763
Rate RDS - Residential Distribution Service	$	0.23996	(0.02909)	(0.03760)	(0.02034)	0.00010	0.13967	0.29270
Rate SCD - Small Commercial Distribution (Choice)	$	0.23996	(0.02909)	(0.03760)	(0.02324)	0.00010	-	0.15013
Rate SGDS - Small General Distribution Service								
Priority One (P1)	$	0.23996	(0.02909)	-	(0.02324)	0.00010	-	0.18773
Non-Priority One (NP1)		-	-	-	-	0.00010	-	0.00010
Rate SDS - Small Distribution Service	$	-	-	-	-	-	-	-
Rate LDS - Large Distribution Service	$	-	-	-	-	-	-	-
Rate MLDS - Main Line Distribution Service	$	-	-	-	-	-	-	-

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Mark Kempic - President

Supplement No. 415 to
Tariff Gas - Pa. P.U.C. No. 9
Seventy-eighth Revised Page No. 21c
Columbia Gas of Pennsylvania, Inc. **Canceling Seventy-seventh Revised Page No. 21c**

Price-to-Compare (PTC) Summary
Rate per thm

Customer Class	PGCC	Gas Cost Adjustment	Capacity Assignment Factor	Rider GPC	Rider MFC	Total Price-to-Compare
Residential	$ 0.36185	0.05245	0.03760	0.00113	0.00570	0.45873
Commercial < = 64,400 thm/year	$ 0.36185	0.05245	0.03760	0.00113	0.00150	0.45453

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Mark Kempic - President

Supplement No. 415 to
Tariff Gas – Pa. P.U.C. No. 9
One Hundred Thirty-second Revised Page No. 151
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Thirty-first Revised Page No. 151**

RIDER PGC - PURCHASED GAS COST

PROVISIONS FOR RECOVERY OF PURCHASED GAS COSTS

RIDER PGC APPLICABLE TO SALES SERVICE CUSTOMERS

Rates for each thm of gas supplied to sales customers subject to this Rider under the Rate RSS, Rate SGSS, Rate LGSS, and Rate MLSS rate schedules shall include $0.62517 per thm for recovery of purchased gas costs. This rate includes the commodity cost component (CC) of $0.36185 per thm, the commodity "E" Factor component (CE) of $0.05245 per thm, the demand cost component (DC) of $0.23996 per thm, and the demand "E" Factor component of ($0.02909) per thm. (I)

RIDER PGC APPLICABLE TO SGDS PRIORITY ONE CUSTOMERS

Rates for each thm of gas distributed under the Rate SGDS rate schedules for Priority-One Service customers shall include $0.21087 per thm for recovery of Purchased Gas Demand Costs (PGDC). This rate includes the DC of $0.23996 per thm and the demand "E" Factor component of ($0.02909) per thm. (I)

RIDER PGC CHARGED TO CHOICE DISTRIBUTION SERVICE CUSTOMERS

Rates for each thm of gas distributed under Rate RDS and Rate SCD shall include $0.17327 per thm for recovery of Purchased Gas Demand Costs. This rate includes the DC of $0.23996 per thm, the Capacity Assignment Factor (CAF) of ($0.03760) per thm and the DC "E" Factor component of ($0.02909) per thm. The CAF represents costs not assignable to Choice Distribution Service customers. (I)(D)

Such rates shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's Regulations, to reflect changes in the level of purchased gas costs, as calculated in the manner set forth below.

PRESENTATION ON CUSTOMER BILLS

For sales service customers served under Rate RSS, Rate SGSS, Rate LGSS and Rate MLSS, the Pass-through Charge includes the PGDC of $0.23996 per thm plus the demand "E" Factor of ($0.02909) per thm. The two factors total $0.21087 per thm. The Gas Supply Charge includes the PGCC of $0.36185 per thm. The Gas Cost Adjustment is the commodity "E" Factor of $0.05245 per thm. (I)

For General Distribution Service customers served under Priority-One Rate SGDS, the Pass-through Charge includes the PGDC of $0.23996 per thm and the demand "E" Factor component of ($0.02909) per thm, totaling $0.21087 per thm. (I)

For Choice Distribution Service customers served under Rate RDS or Rate SCD, the Pass-through Charge includes the PGDC of $0.23996 per thm, the CAF of ($0.03760) per thm and the demand "E" Factor component of ($0.02909) per thm, all of which total $0.17327 per thm. (I)(D)

QUARTERLY UPDATES

The Company's rates for recovery of purchased gas costs are also subject to quarterly adjustments under procedures set forth in the Commission's regulations at 52.Pa. Code § 53.64 (i) (5). Such updates shall reflect, in addition to the provisions of the regulation, adjustments to the projected commodity cost of purchased gas based upon more current versions of the same sources of data and using the same methods to project the commodity cost of purchased gas approved by the Commission in the Company's most recent annual proceeding for recovery of purchased gas costs under section 1307(f) of the Public Utility Code.

(D) Indicates Decrease (I) Indicates Increase

RIDER PGC - PURCHASED GAS COST (Continued)

COMPUTATION OF PURCHASED GAS DEMAND COSTS PER THM – Continued

Supplier Refunds and Pipeline Penalty Credits that are not included in "CE" will be included in the calculation of "DE". Supplier Refunds and Pipeline Penalty Credits will include interest added at the annual rate of six percent (6%) calculated from the month received to the effective month such refund is refunded. The period over which such refunds will be made shall be established by the Commission.

"S" - projected thms of gas to be billed to customers under the distribution charges of the Rate RSS, Rate SGSS, Rate LGSS, and Rate MLSS rate schedules plus the projected thm of gas to be distributed to customers under Rate RDS, Rate SCD and SGDS Priority One Distribution rate schedules of this Tariff during the period when rates will be in effect.

The portion of Supplier Refunds and Penalty Credits that would otherwise be credited to residential customers shall be credited to the Hardship Fund (mentioned in the USP Rider section of this tariff) when the balance of the Hardship Fund falls below $750,000. The non-residential portion of Supplier Refunds and Penalty Credits will be credited to applicable non-residential customers through the PGC. When the Hardship Fund balance is $750,000 or more, and Pipeline Supplier Refunds and Pipeline Penalty Credits received by the Company will be included in the calculation of the PGDC as specified above.

PROVISION OF PURCHASED GAS DEMAND COST CREDIT DUE TO CUSTOMERS ELECTING CHOICE DISTRIBUTION SERVICE – CAPACITY ASSIGNMENT FACTOR (CAF)

The Purchased Gas Demand Cost (PGDC) rate included in the Pass-through Charge billed to Choice Distribution Service customers served under Rate RDS or Rate SCD shall be $0.20236 per thm. Such rate shall be equal to the PGDC component of $0.23996 per thm as calculated above, less the CAF of $0.03760 per thm. The CAF shall be equal to the projected annual cost of assigned Firm Capacity less estimated annual storage commodity costs (storage injection, withdrawal, shrinkage and commodity transportation cost) with the net divided by the estimated, normalized annual usage of customers electing Choice Distribution Service. The CAF of $0.03760 per thm representing costs not assignable to CHOICE customers shall be included in the Price-to-Compare. (I)

DETERMINATION OF OVER/UNDERCOLLECTION OF GAS COSTS

Commodity E-factor

In computing the experienced over/under collection of purchased gas commodity costs for a period defined by the Commission, the following procedure shall be used:

(a) All experienced purchased gas commodity costs actually incurred by the Company to service customers pursuant to all rate schedules of this Tariff.

Experienced purchased gas commodity costs shall include, but not be limited to, the following:

(1) payments to suppliers to accept assignment of capacity on interstate pipelines other than Columbia Gas Transmission, LLC to the extent permitted under the Rules Applicable to Distribution Service;

(2) costs paid for employing futures, options and other risk management tools, including but not limited to, supplier related costs associated with the fixed price contracts or financial contracts utilized by the Company to lessen the impact of price volatility for PGC customers; and

(3) the index price of gas purchased from distribution customers under the provisions of the Deliveries in Excess of Consumption section of Paragraph 3 of the Rules Applicable to Distribution Service.

(D) Indicates Decrease (I) Indicates Increase

COLUMBIA STATEMENT NO. 4

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2026-3060762
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF

PATRICK J. PLUARD

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2026

Q. Please state your name, business address and title.

A. My name is Patrick J. Pluard. My business address is 1500 165th Street, Hammond, Indiana 46324. I am the Director of Portfolio Optimization in the Energy Supply and Trading Department for Northern Indiana Public Service Co. ("NIPSCO"), a subsidiary of NiSource Inc. ("NiSource").

Q. Please describe your educational and employment background.

A. I attended Purdue University, where I graduated with a Bachelor of Science in Marketing in 1994 and a Master's in Business Administration in 2000. I began my employment with NiSource in 2004 as a Real Time Energy Trader. In 2008, I transferred to operations as a Generation System Supervisor. In 2011, I was promoted to Manager of Day Ahead Asset Optimization. I was promoted to my current role, Director of Portfolio Optimization, in March of 2013.

Q. What are your responsibilities as Director of Portfolio Optimization?

A. As Director of Portfolio Optimization, I am responsible for a team consisting of system operators, engineers and gas portfolio managers that manage gas and electric assets for NiSource subsidiaries. Specific to this filing, my team is responsible for meeting the daily needs of Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or the "Company") customers through procurement of natural gas utilizing transportation and storage portfolio assets in a safe and reliable manner at the lowest reasonable cost.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission")?

A. Yes. I was a rebuttal witness in the Company's 2022 1307(f) proceeding at Docket

No. R-2022-3031172, a witness in the 2023 1307(f) proceeding at Docket No. R-2023-3038630, a witness in the 2024 1307(f) proceeding at Docket No. R-2024-3047014 and a witness in the 2025 1307(f) proceeding at Docket No. R-2025-3053663.

Q. Have you previously testified before any other state utility commission?

A. Yes, I have testified for NIPSCO before the Indiana Utility Regulatory Commission as a Gas Cost Accounting and Green Power Rider witness. I have also testified for Columbia Gas of Kentucky, Inc.'s Price Based Rates mechanism renewal request.

Q. What is the purpose of your Direct Testimony in this proceeding?

A. The purpose of my Direct Testimony is to: (1) explain Columbia's gas purchasing and procurement strategies to acquire the least cost reliable gas supplies to serve its customers; (2) discuss Columbia's successful Unified Sharing Mechanism ("USM") for sharing net proceeds from capacity releases and off-system sales; and (3) provide an update on the financial hedging program approved in the 2023 1307(f) proceeding.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the exhibits identified in Table 1 below, which were included with Columbia's pre-filing data submitted on February 27, 2026:

Table 1

Number	Description	Regulation
Company Exhibit 1-D-1	**Detail of Contracts and Negotiations**	**53.64(c)(1)**
Company Exhibit 1-D-2	**Detail of Take-or-Pay and Minimum Bill Provisions**	**53.64(c)(1)**
Company Exhibit 1-D-3	**List of Maximum Daily Quantity Levels and Maximum Annual Quantity Levels**	**53.64(c)(1)**
Company Exhibit 6	**List of Off-System Sales**	**53.64(c)(7)**
Company Exhibit 8-A	**Cost of Affiliated Gas as Compared to the Average Market Price of Other Pipeline Suppliers and Other Sources**	**53.65(1)**
Company Exhibit 8-B	**Estimates of the Quantity of Gas Available to the Company from All Sources**	**53.65(2)**
Company Exhibit 8-C	**Efforts Made by the Company to Obtain Gas Supply from Non-affiliated Interests**	**53.65(3)**
Company Exhibit 8-D	**Demonstration that Purchases from an Affiliated Interest are Consistent with a Least Cost Procurement Policy**	**53.65(4)**
Company Exhibit 8-E	**Source and Amount of All Supplies Withheld from the Market by the Company or its Affiliates**	**53.65(5)**

Q. Do you have any revised exhibits?

A. No.

I. COLUMBIA'S SUPPLY AND CAPACITY PROCUREMENT

Q. What are Columbia's gas purchasing objectives and strategies?

A. Columbia has a least cost objective to secure and deliver competitively priced, reliable gas supplies for its customers. Columbia is sensitive to the impact of gas costs on its customers and balances this concern with its obligation to provide

reliable gas supplies to its firm customers whenever they want gas service under a wide range of weather conditions.

Columbia's gas purchasing strategy is to contract for a portfolio of gas supplies and capacity that has the flexibility both to meet reliability standards and be able to take advantage of low-price opportunities when available and operationally feasible.

Q. What are Columbia's gas procurement policies?

A. Columbia contracts for sufficient firm gas supplies to serve, at a minimum, the demand of its firm service customers under design weather conditions, both design day and seasonal. Firm gas supplies include storage supplies, purchases under firm gas supply contracts and firm monthly and daily gas supply purchases, delivered through firm transportation capacity and local gas supplies on a seasonal basis. Firm gas supply contracts can include both long-term and short-term contracts that provide the supplier with an incentive to deliver supplies with a high degree of reliability on a daily and seasonal basis.

In contracting for firm gas supplies, Columbia purchases firm gas supplies during the winter months to assure sufficient gas supplies are available in the event Columbia experiences colder than normal daily temperatures. Columbia purchases firm supplies to provide flexibility in recognition of annual fluctuations in seasonal and daily demand and minimize gas costs for its customers.

Q. Please address Columbia's segmentation of its gas supply contracts.

A. Columbia's contracts are presently segmented into two categories: short-term and spot market. Columbia defines short-term contracts as firm gas purchase

agreements with a contract length of one year or less. Spot market contracts are gas purchases made at the time of need for between one day and one month in length.

Q. How does Columbia determine prices under these contracts?

A. Prices under firm short-term contracts are typically based on a nationally published index plus a small premium. The index and premium are established as a result of the request for proposal ("RFP") and contract negotiation process. Spot market contract prices are based on market conditions negotiated at the time of purchase.

Q. Please explain the premium Columbia pays under its firm purchase contracts that it enters into on a short-term basis.

A. Columbia negotiates a nominal premium with suppliers for purchases under its short-term gas purchase agreements to assure Columbia and its customers of sufficient firm, reliable gas supplies at competitive prices, under widely varying weather and market conditions.

Q. Please describe the process Columbia follows to acquire short-term firm supplies over a period in excess of one month.

A. Annually, Columbia submits an RFP to numerous suppliers identified as capable and willing to provide firm gas supplies to Columbia. Columbia requests proposals for supplies with varying term lengths, nomination flexibility and innovative pricing options. Upon receipt of proposals submitted in response to the RFP, Columbia evaluates the responses and begins negotiations with suppliers whose proposals provide the required supply assurances at the least cost. Negotiations continue until satisfactory agreements are reached or until an impasse is reached, after which another supplier negotiation is initiated.

Q. What were the results of your most recent RFP cycle?

A. For the 2025-2026 winter, Columbia entered into eleven new term gas purchase agreements.

Q. Does Columbia purchase spot market gas supplies in volumes exceeding its Firm Transportation Service ("FTS") contract level during the summer months?

A. Yes. In order for Columbia to inject sufficient gas supplies into its storage accounts, particularly its Firm Storage Service account with Columbia Gas Transmission, LLC ("TCO"), to meet winter season customer demand, it must purchase gas supplies in volumes exceeding its FTS capacity during the summer. These additional gas purchases are made under spot market contracts and delivered to its storage accounts using Columbia's Storage Service Transportation capacity at secondary receipt and delivery points.

Q. Did Columbia seek RFP bids for the provision of firm service natural gas supplies to Texas Eastern Transmission, LP ("TETCO") Zone M-3 delivery points at Texas Eastern M-2 Zone index prices?

A. Yes, Columbia's 2025-2026 winter TETCO RFP included a pricing option for bids for the provision of firm natural gas supplies delivered to TETCO Zone M-3 points at TETCO M-2 Zone index prices. Bids were received and reviewed, and based on the review, Columbia did award an Asset Management Arrangement ("AMA").

Q. What are Columbia's projected gas sales for the 12 months ending September 30, 2026, which is the application period for gas costs under § 1307(f) of the Public Utility Code?

A. As shown in Company Revised Exhibit 1-A, Schedule 1, Sheet 1, line 4, Columbia's projected sales for the 12 months ending September 30, 2026, total 384,465,070 therms.

Q. Does this amount include sales by Natural Gas Suppliers under Columbia's Customer CHOICE℠ program?

A. No, only projected sales by Columbia are included in Company Revised Exhibit 1-A, Schedule 1, Sheet 1, line 4.

Q. Does Columbia purchase supply from Pennsylvania production?

A. Yes, Columbia maintains a program for purchasing local Pennsylvania production. A portion of the local production is delivered directly into Columbia's distribution system. Columbia purchases a second portion at TCO's Appalachian receipt points. Purchases made with Appalachian receipt point transportation capacity are often made at pools or aggregation points, where volumes of local gas become commingled with gas supplies from other sources. Therefore, it becomes impossible to determine how much of those supplies are produced in Pennsylvania.

Q. Did Columbia exceed $100,000.00 in Operational Flow Order, overrun or other penalties during the PGC year (February 2025 – January 2026)?

A. No, Columbia had a total of approximately $965 of overrun charges during this period.

II. UNIFIED SHARING MECHANISM ("USM")

Q. Columbia manages its off-system sales and capacity release programs under its USM. Please explain.

A. A market exists for Natural Gas Distribution Companies, such as Columbia, to market unbundled and re-bundled gas and capacity products to non-traditional customers. Columbia's off-system sales and capacity release programs provide Columbia and its customers an opportunity to benefit from the unbundling of interstate pipeline services implemented by Federal Energy Regulatory Commission ("FERC") Order 636. Columbia's off-system sales incentives began in January 1995, and capacity release incentives began in February 1996. In the Company's 2009 Section 1307(f) proceeding (Docket No. R-2009-2093219), the Commission approved a revision to the unified off-system sales and capacity release sharing mechanisms commencing October 1, 2009, and operating for a three-year period. The USM established by the Commission's Order in Columbia's 2009 1307(f) proceeding provided that customers receive 75% of the net USM proceeds, while Columbia receives the remaining 25% of the incentive. In the Company's 2012 Section 1307(f) proceeding (Docket No. R-2012-2293303), the Commission approved the parties' agreement that Columbia's current 75% customer/25% Company USM shall continue indefinitely, absent Commission directive to the contrary. This Order provided that in future proceedings parties may propose changes to the USM. Pursuant to the Commission's Order in Columbia's 2013 1307(f) case (Docket No. R-2013-2351073), slight modifications were made to the USM calculation with respect to

the methodology utilized to apply applicable credits; however, all other aspects of the USM remained unchanged. Pursuant to the Commission's Order in the Company's 2014 1307(f) case (Docket No. R-2014-2408268), Columbia performed an evaluation in its 2015 1307(f) pre-filing of whether the existing allocation of the customers' share of USM credits between the Purchased Gas Commodity Cost ("PGCC") and the Purchased Gas Demand Cost ("PGDC") within the PGC should be modified. The Commission, in its Order in the 2015 1307(f) proceeding (Docket No. R-2015-2469665), directed that the pass back of the customers' share of USM credits be made 100% through the PGDC. Columbia implemented this methodology effective with its October 1, 2015 PGC compliance filing.

Q. What are the historical results of Columbia's USM?

A. Table 2 below provides lists the historic total off-system sales margins and capacity release revenues, as well as the Company and customer shares and percentages of Columbia's USM. Actual data is provided for prior USM program sharing mechanisms through the year ending September 30, 2025. Data for the current USM program year ending September 30, 2025, includes actual booked margins through September 2025 and estimated incremental revenue from October 2025 through September 30, 2026.

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TABLE 1
Historic and Projected Unified Sharing Mechanism Customer and Company Share

Historic Period	USM Total Margin ($)	Customer Share ($)	Customer Share (%)	Company Share ($)	Company Share (%)
Oct 2002 – Sept 2003	$17,424,586	$8,556,146	46.10%	$8,868,440	50.90%
Oct 2003 – Sept 2004	$15,256,111	$8,539,028	55.97%	$6,717,083	44.03%
Oct 2004 – Sept 2005	$15,112,450	$10,556,225	69.85%	$4,556,225	30.15%
Oct 2005 – Sept 2006	$13,914,577	$9,957,288	71.56%	$3,957,289	28.44%
Oct 2006 – Sept 2007	$19,309,539	$13,691,677	70.91%	$5,617,862	29.09%
Oct 2007 – Sept 2008	$14,383,502	$10,243,451	71.22%	$4,140,051	28.78%
Oct 2008 – Sept 2009	$11,152,477	$8,106,734	72.69%	$3,045,743	27.31%
Oct 2009 – Sept 2010	$11,851,708	$8,888,781	75%	$2,962,927	25%
Oct 2010 – Sept 2011	$10,312,511	$7,734,383	75%	$2,578,128	25%
Oct 2011 – Sept 2012	$5,597,628	$4,198,221	75%	$1,399,407	25%
Oct 2012 – Sept 2013	$7,479,592	$5,609,694	75%	$1,869,898	25%
Oct 2013 – Sept 2014	$15,950,716	$11,963,037	75%	$3,987,679	25%
Oct 2014 – Sept 2015	$12,124,848	$9,093,636	75%	$3,031,212	25%
Oct 2015 – Sept 2016	$12,278,866	$9,209,149	75%	$3,069,717	25%
Oct 2016 – Sept 2017	$10,052,000	$7,540,000	75%	$2,512,000	25%
Oct 2017 – Sept 2018	$6,728,427	$5,046,320	75%	$1,682,107	25%
Oct 2018 – Sept 2019	$4,231,608	$3,173,706	75%	$1,057902	25%
Oct 2019 – Sept 2020	$1,813,318	$1,359,989	75%	$453,329	25%
Oct 2020 – Sept 2021	$2,370,807	$1,778,106	75%	$592,702	25%
Oct 2021 – Sept 2022	$2,375,976	$1,781,982	75%	$593,994	25%
Oct 2022 – Sep 2023	$4,470,583	$3,352,937	75%	$1,117,646	25%
Oct 2023 – Sept 2024	$4,196,618	$3,147,463	75%	$1,049,154	25%
Oct 2024 – Sep 2025	$4,964,962	$3,723,721	75%	$1,241,240	25%
Oct 2025 – Sept 2026 (est.)	$3,287,476	$2,465,607	75%	$821,869	25%

III. FINANCIAL HEDGING PROGRAM

Q. Per the Commission-approved Settlement of Columbia's 2023 1307(f) proceeding, did Columbia execute the financial hedges according to the agreed upon program?

A. Yes. Consistent with the approved 2023 1307(f) Settlement (Docket No. R-2023-3038630), Columbia executed the financial hedges shown in Table 3 below.

Table: 3 – Financial Hedge Summary

Month	Vol/Month	Vol/Day	Price	Purch. Value	
4/1/2024	660,000	22,000	$2.55	$1,679,700	Summer '24 executed 12/19/23
5/1/2024	660,000	21,290	$2.55	$1,679,700	JPMorgan
6/1/2024	660,000	22,000	$2.55	$1,679,700	
7/1/2024	660,000	21,290	$2.55	$1,679,700	
8/1/2024	660,000	21,290	$2.55	$1,679,700	
9/1/2024	660,000	22,000	$2.55	$1,679,700	
10/1/2024	660,000	21,290	$2.55	$1,679,700	
11/1/2024	670,000	22,333	$3.58	$2,401,280	Winter '24'25 to be executed 1/24/24
12/1/2024	670,000	21,613	$3.58	$2,401,280	JPMorgan
1/1/2025	670,000	21,613	$3.58	$2,401,280	
2/1/2025	670,000	23,929	$3.58	$2,401,280	
3/1/2025	670,000	21,613	$3.58	$2,401,280	
4/1/2025	670,000	22,333	$3.12	$2,090,400	Summer'25 executed 2/16/24
5/1/2025	670,000	21,613	$3.12	$2,090,400	J. Aron (Goldman Sachs)
6/1/2025	670,000	22,333	$3.12	$2,090,400	
7/1/2025	670,000	21,613	$3.12	$2,090,400	
8/1/2025	670,000	21,613	$3.12	$2,090,400	
9/1/2025	670,000	22,333	$3.12	$2,090,400	
10/1/2025	670,000	21,613	$3.12	$2,090,400	
11/1/2025	660,000	22,000	$4.09	$2,699,400	Winter '25'26 to be executed November 2025
12/1/2025	660,000	21,290	$4.09	$2,699,400	Bank of America (BAML)
1/1/2026	660,000	21,290	$4.09	$2,699,400	
2/1/2026	660,000	23,571	$4.09	$2,699,400	
3/1/2026	660,000	21,290	$4.09	$2,699,400	

4/1/2026	660,000	22,000	$3.44	$2,267,100	Summer '26 to be executed April 2026
5/1/2026	660,000	21,290	$3.53	$2,329,800	JPMorgan
6/1/2026	660,000	22,000	$3.56	$2,346,960	
7/1/2026	660,000	21,290	$3.75	$2,471,700	
8/1/2026	660,000	21,290	$3.52	$2,319,900	
9/1/2026	660,000	22,000	$3.49	$2,302,740	
10/1/2026	660,000	21,290	$3.58	$2,362,800	
11/1/2026	660,000	22,000	$3.80	$2,509,320	
12/1/2026	660,000	21,290	$4.31	$2,844,600	
1/1/2027	660,000	21,290	$4.74	$3,128,400	
2/1/2027	660,000	23,571	$4.40	$2,900,700	
3/1/2027	660,000	21,290	$3.63	$2,392,500	
5/1/2027	670,000	21,613	$3.31	$2,214,350	
6/1/2027	670,000	22,333	$3.62	$2,423,390	
7/1/2027	670,000	21,613	$3.80	$2,546,000	
8/1/2027	670,000	21,613	$3.76	$2,515,850	
9/1/2027	670,000	22,333	$3.75	$2,512,500	
10/1/2027	670,000	21,613	$3.83	$2,566,100	
11/1/2027	660,000	22,000	$4.03	$2,659,800	
12/1/2027	660,000	21,290	$4.49	$2,963,400	
1/1/2028	660,000	21,290	$4.74	$3,130,380	
2/1/2028	660,000	22,759	$4.21	$2,778,600	
3/1/2028	660,000	21,290	$3.48	$2,298,120	

Q. Can you provide an example of how the transactions will settle on a monthly basis?

A. Yes. The product is known as a "fixed to float," whereby the price is fixed upon execution and settles out monthly at the NYMEX Henry Hub futures expiration price. For example, when Columbia fixed the April 2026 financial contract at $3.44 per dekatherm day, the market floats between now and April 2026. Upon the expiration of the April 2026 contract in March 2026 the difference between the expiration price and fixed price is exchanged between Columbia and the supplier. Assuming the April 2026 contract expires at $3.50 per dekatherm day,

the supplier would pay Columbia the difference of $.06 per dekatherm day. The funds would flow through to the PGC customers creating a netting effect of locking in a $.06 per dekatherm day gain against the $3.44 per dekatherm day April purchase, fixing the April price to the customer at $3.44 per dekatherm day.

VI. Certified Natural Gas

Q. Did Columbia purchase Certified Natural Gas during the applicable review period?

A. No. While Columbia did not purchase any certified natural gas or related certificates, Columbia continues to gather insight, develop relationships and is working to develop a position on this issue. Columbia, being part of NiSource, is in contact with various certifying agencies and options for this product. Columbia will continue to monitor this industry initiative and provide updates as it progresses.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.